Volume II

6: Capital Projects
$50,000 to $200,000

Install Infrared Scanning Ports – Happy Valley Gas Turbine

Category:	Generation – Gas Turbines
Definition:	Other
Classification:	Normal
Investment Classification:	Service Enhancement

1.0 Introduction

This project consists of the procurement and installation of infrared view ports on high voltage electrical equipment associated with the Happy Valley Gas Turbine. Infrared view ports are windows through which thermal inspections can be safely performed. The use of the view ports decreases the need to physically access live electrical equipment.

2.0 Background

View ports make it possible to safely perform thermography studies on electrical equipment while it is in service which can identify potential issues and prevent unexpected failures.

2.1 Existing Equipment

The electrical system at the Happy Valley Gas Turbine is largely original to the plant, which was placed in service in 1992. The plant electrical system consists of a 600 V motor control centre ("MCC") and 13.8 kV switchgear. The MCC houses the required disconnects, breakers, and overloads to control and protect the various motors installed throughout the plant. The 13.8 kV switchgear connects the gas turbine's alternator to the switchyard.

2.2 Operating Experience

Inspections on high voltage electrical cabinets can be completed with the equipment de-energized or while the equipment is energized and under load. De-energizing equipment for inspections does not usually allow for the accurate and proactive detection of hotspots. The inspection of electrical equipment while it is under load allows for real-time evaluation and more accurate inspection results and can also assist in the identification of loose connections, deteriorated connections, and other issues. At present, inspections of the 600 V MCC and 13.8 kV switchgear within the Happy Valley Gas Turbine are conducted on an annual basis. Newfoundland and Labrador Hydro ("Hydro") personnel remove covers to gain access to the energized equipment and are required to utilize arc-rated personal protective equipment during this work to provide protection against arc flash and electrical hazards. The use of infrared view ports allows these inspections to be completed without exposing workers to the electrical and arc-flash hazards created when the equipment is uncovered.

Similar view port installations have been completed at Hydro's other hydroelectric generating stations such as Bay d'Espoir, Cat Arm, Granite Canal, Hinds Lake, Upper Salmon, and Paradise River.

3.0 Justification

Completing this project in 2023 will eliminate the arc-flash hazard associated with inspections on high voltage electrical cabinets, resulting in improved safety for maintenance staff. It will also allow electrical equipment thermal inspections to be performed more frequently and expediently as it eliminates the downtime required to de-energize the equipment and install work protection.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Install view ports.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

This alternative is for the deferral of this project into a future year. The option of not proceeding with this project was evaluated and was determined not to be an acceptable alternative due to the safety implications for the staff who are currently required to manually perform inspections on energized equipment.

4.2.2 Alternative 2: Install View Ports

Completing this project in 2023 will eliminate the arc-flash hazard associated with these critical maintenance tasks resulting in improved safety for maintenance staff working on the Happy Valley Gas Turbine.

4.3 Proposed Alternative

Hydro is proposing to install infrared view ports to reduce the risk of safety issues during the completion of electrical inspections at the Happy Valley Gas Turbine facility. The use of view ports will also improve maintenance by permitting inspections to be completed more frequently.

5.0 Project Description

The scope of this project includes the installation of infrared view ports in the following locations:

- The 600 V MCC;
- The door of the 13.8 kV switchgear cabinet; and
- The door of the 13.8 kV breaker cabinet.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	3.9	0.0	**3.9**
Labour	31.3	15.7	0.0	**47.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.5	0.0	0.0	**2.5**
Interest and Escalation	2.5	3.9	0.0	**6.4**
Contingency	3.3	2.1	0.0	**5.4**
Total	**39.6**	**25.6**	**0.0**	**65.2**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project and review schedule	July 2022	August 2022
Design:		
Conduct site visit and complete detailed design	September 2022	October 2022
Procurement:		
Procure required materials	November 2022	February 2023
Construction/Commissioning:		
Installation of view ports	June 2023	July 2023
Close Out:		
Project close out	July 2023	August 2023

6.0 Conclusion

Thermal scans of equipment while it is under load assists in the identification of electrical issues such as poor connections. The installation of infrared view ports on high-voltage electrical equipment located within the Happy Valley Gas Turbine is proposed to reduce safety risks to personnel who conduct thermal scans and improve maintenance by permitting inspections to be completed more frequently.

Upgrade Wastewater Treatment Plant 600 V Variable Frequency Drives – Holyrood

Category:	Generation – Thermal Plant
Definition:	Other
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

This is a one-year project required to support the reliable operation of the wastewater treatment plant at the Holyrood Thermal Generating Station ("Holyrood TGS"). The scope of work includes the replacement of obsolete variable frequency drives ("VFD").

2.0 Background

The Holyrood TGS Wastewater Treatment Plant processes wastewater from air pre-heater washes, boiler washes, runoff from the solid waste landfill, and batch reactor return waste. Solid waste is compressed through the batch reactor and brought to the landfill, while the treated liquid waste is released into Indian Pond. Eight VFDs control motors and pumps that are required for the treatment process.

2.1 Existing Equipment

The VFDs were installed in the late 1990s during the wastewater treatment plant retrofit and are now obsolete. The manufacturers are no longer servicing these VFDs.

2.2 Operating Experience

As the existing VFDs are no longer supported by the manufacturer, spares cannot be obtained. In 2018, one of the VFDs failed and had to be replaced with a newer model design.

3.0 Justification

Treatment of wastewater resulting from air pre-heater washes, boiler washes, runoff from the solid waste landfill, and batch reactor is required for current Holyrood TGS operations and will continue to be required to support synchronous condenser operations. These functions cannot be performed without

VFDs. As the existing VFDs that are required for the wastewater treatment function are no longer supported by the manufacturer, replacement of the VFDs in the wastewater treatment plant is necessary at this time to support continued reliable treatment of wastewater.

4.0 Analysis

4.1 Identification of Alternatives

Newfoundland and Labrador Hydro evaluated the following alternatives:

- Alternative 1: Deferral of the replacement of the VFDs; and
- Alternative 2: Replace the VFDs.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral of the Replacement of the VFDs

Under this alternative, the existing VFDs would be inspected regularly and checked for faults or irregular operation. If one or more VFD fails, there are no spare parts or manufacturer support. In this circumstance, wastewater process control would be impaired and could result in irregular operation of the wastewater treatment plant until a new VFD could be procured, installed, and commissioned.

4.2.2 Alternative 2: Replace the VFDs

Under this alternative, the end-of-life VFDs would be replaced and commissioned to meet the wastewater treatment plant's requirements. Completing the replacement during a planned outage will ensure that the work can be completed in a manner that minimizes disruption to the wastewater treatment process. Additionally, the new system would have an improved end-of-life duration and spare parts would be available if a VFD was damaged. The new VFDs would increase reliability of the wastewater treatment plant.

4.3 Proposed Alternative

To support continued reliable operation and extend the life of the wastewater treatment plant, Alternative 2 is the proposed alternative.

5.0 Project Description

The scope of this project involves the replacement of obsolete VFDs with new VFDs.

The scope of the project includes:

- Detailed design for replacement of the existing VFDs;
- Procurement of new VFDs;
- Design of controls interface between the old systems and new VFDs;
- Creation of energization and commissioning plans;
- Installation of the new equipment;
- Commissioning of new equipment; and
- Verification of the system operation.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	13.6	0.0	0.0	**13.6**
Labour	44.2	0.0	0.0	**44.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	2.5	0.0	0.0	**2.5**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	3.8	0.0	0.0	**3.8**
Contingency	6.0	0.0	0.0	**6.0**
Total	**70.1**	**0.0**	**0.0**	**70.1**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Project start-up and scheduling	February 2022	March 2022
Design:		
Electrical and P&C review, design, and tender creation	March 2022	July 2022
Procurement:		
VFD and commissioning tender	June 2022	July 2022
Construction:		
Installation	August 2022	September 2022
Commissioning:		
Third-party set- up, configuration, and testing	September 2022	October 2022
Close Out:		
Finalizing all project payments, documentation, and paperwork.	October 2022	November 2022

6.0 Conclusion

Replacement of the existing obsolete VFDs that control the wastewater treatment plant processes is required to support the reliable treatment of wastewater during both generation and synchronous condenser operation, ensuring environmental compliance is maintained.

Control System Replacement – Holyrood Gas Turbine

Category: Generation – Gas Turbines

Definition: Other

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

The Holyrood Gas Turbine control system consists of hardware and software components that control and monitor plant equipment such as the turbine, circuit breakers, transformers, and auxiliary equipment. Control can be performed either automatically or interactively via operators utilizing computer stations known as human-machine interfaces ("HMI").

The control system hardware consists of processors, input/output modules, computer stations, network switches, and servers. Control system software installed on the computer stations and servers provides control, equipment set-point adjustments, alarms, trip actions, and collection of historical information from connected equipment. In recent years, hardware components within the control system have failed resulting in the inability of the operators to monitor and control the generating unit.

2.0 Background

2.1 Existing Equipment

The existing Rockwell Control System was installed in 2015 and consists of five main hardware elements:

1) Processors;
2) Input/output modules;
3) Computer stations;
4) Network switch; and
5) Historian server.

The project consists of the replacement of three computer stations, one network switch, and one Historian server as well as the addition of software to implement HMI server application redundancy.

2.1.1 Computer Stations

The existing computer stations are six-year-old Dell Precision T3610 workstations. Computer stations can be categorized as either engineering stations or HMI clients:

- Engineering stations are used to store and modify the processor configurations, view overall control system health information, and host the HMI server application; and
- HMI clients communicate with the HMI server application and allow operators to monitor and control the plant equipment from a safe and noise-free environment. HMI clients also show current operating values, equipment set-points, equipment status (e.g., open/closed, on/off, etc.), and display process alarms.

2.1.2 Network Switch

The network switch is used to transfer information between processors, the Historian server, and the computer stations. The existing network switch does not have the capability to provide remote access to the computer stations and Historian server which makes troubleshooting of plant equipment less efficient.

2.1.3 Historian Server

The existing Historian server is a six-year-old Dell Server PowerEdge T110ii server. It collects historical information such as equipment trending and alarm history. The information collected is used to aid in planning maintenance activities as well as troubleshooting operating issues at the plant.

2.1.4 HMI Server Application

At the Holyrood Gas Turbine, there is only one HMI server application that provides operating information to each of the two HMI clients. If the HMI server application is not functional, the operator will not be able to control and monitor from either of the two HMI clients. A redundant HMI server application installed on a different engineering station would substantially mitigate the risk of losing the ability to control and monitor plant equipment from the HMI clients.

2.2 Operating Experience

The Rockwell Control System has been in operation full-time since construction of the Holyrood Gas Turbine in 2015. Since installation, there have been two major hardware component failures within the computer stations. In 2018, a power supply failed. The original computer station supplier no longer provides replacement power supplies for the existing installed model so a used replacement had to be purchased to resolve the issue. In 2021, the hard drive failed on the engineering station running the HMI server application. New hard drives from the original computer station supplier are not compatible with the existing computer station so a used, older model hard drive had to be located and reconfigured to resolve the issue.

The lack of available original supplier hardware highlights the vulnerabilities of the computer stations and Historian server.

3.0 Justification

The Holyrood Gas Turbine control system has the following vulnerabilities:

- Hardware components for the six-year-old computer stations and Historian server are not available from the original supplier;
- The operating systems installed on the computer stations (Windows 7) and Historian server (Windows Server 2008) are obsolete and no longer supported; and
- The HMI server application is not redundant, resulting in a single point of failure for operator control and monitoring.

These vulnerabilities increase the probability of an extended outage if components fail during operation. For example, if the engineering station fails, the HMI server application will be offline and the operators will not be able to monitor and control from the HMI clients. If components cannot be sourced to complete repairs, the whole engineering station will require replacement. Replacement would take weeks to complete and the operator would not be able to monitor and control the generating unit during this time, resulting in an extended unplanned outage.

4.0 Analysis

4.1 Identification of Alternatives

Newfoundland and Labrador Hydro ("Hydro") evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Upgrade control system.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Deferral would require Hydro to complete repairs upon failure of hardware components associated with computer stations and the Historian server. If repairs are not possible due to inability to source failed hardware components, full replacement of a computer station or Historian server would be required. Replacing this hardware outside of a scheduled shutdown would require an extended unplanned outage to complete the replacement and fully test the resulting software configuration changes on the new hardware.

Deferring the project increases the risk of in-service failure, which could result in unit outages during Hydro's winter 2023–2024 operating season. This alternative presents an unacceptable risk to Hydro's ability to safely and reliably meet customer needs while the Holyrood Gas Turbine is in operation.

4.2.2 Alternative 2: Upgrade Control System

Under this alternative, the control system Historian server, computer stations, and network switch would be replaced with the latest hardware product offerings, running current operating systems. The Rockwell Control System software would also have to be updated to the latest product offerings to run on the new operating systems. A planned approach would mitigate unforeseen outage time for the foreseeable future. Under this approach, factory acceptance testing would be completed in a test environment which would provide a high level of confidence that the new system will function as intended during site installation and commissioning.

4.3 Proposed Alternative

Hydro proposes to upgrade the control system hardware and associated software in 2022–2023. This approach will bring the hardware and associated software up to date so that replacements are readily available in the case of failure, and operating systems are supported. Furthermore, it will improve the availability of the system by adding HMI server application redundancy and allowing remote access to control system elements to troubleshoot issues with the plant equipment. This approach would allow Hydro to complete the replacement in a planned manner while continuing to safely and reliably operate the Holyrood Gas Turbine.

5.0 Project Description

This project includes the replacement of elements of the Holyrood Gas Turbine control system hardware and associated software.

Hardware replacements will include three computer stations, one network switch, and one Historian server. These will come equipped with the latest supported operating systems.

The latest software offerings from Rockwell will be installed on the new computer stations and Historian server. Also included is the redundant HMI server application. The new Rockwell software will be verified in a test environment to ensure new configurations are functional prior to installation at the Holyrood Gas Turbine.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	62.5	0.3	0.0	**62.8**
Labour	61.7	30.5	0.0	**92.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.2	0.5	0.0	**0.7**
Interest and Escalation	9.1	6.6	0.0	**15.7**
Contingency	12.5	3.1	0.0	**15.6**
Total	**146.0**	**41.0**	**0.0**	**187.0**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare project plan	February 2022	March 2022
Design:		
Complete detailed design	March 2022	April 2022
Procurement:		
Order equipment	May 2022	July 2022
Factory Acceptance Testing:		
Verify new hardware and software in test environment	September 2022	September 2022
Construction/Commissioning:		
Replace computer stations, network switch, and server	April 2023	April 2023
Close Out:		
Complete project close out activities	July 2023	July 2023

6.0 Conclusion

To support the continued safe and reliable operation of the Holyrood Gas Turbine, Hydro recommends replacement of elements of the control system hardware and associated software as described above. This project will materially reduce the risk of an extended unplanned outage at the Holyrood Gas Turbine due to control system hardware issues.

Replace Radomes (2022) – Various

Category: General Properties – Telecontrol – Network Services

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") is proposing a project for the replacement of microwave antenna radomes in 2022.[1] Hydro's radome asset management replacement criteria are based on operational experience and the manufacturers' recommendations and are focused on reducing the probability of electrical system outages resulting from radome failure. Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2022–2026 is provided in Appendix A.

2.0 Background

2.1 Existing Equipment

The main purpose of Hydro's microwave radio system is to protect and control Hydro's generation and transmission assets. These include the 230 kV terminal stations from St. John's to Bay d'Espoir, the hydroelectric generating facilities at Bay d'Espoir, Granite Canal, and Upper Salmon as well as the required control structures. Hydro has a network of microwave radios by which corporate communications and system data are transmitted. The microwave radio system provides the backbone for all corporate voice and data communications. Traffic carried over the microwave system includes:

- Teleprotection signals for the provincial transmission system;
- Data pertaining to the provincial Supervisory Control and Data Acquisition System;
- Data pertaining to the corporate administrative system; and
- Operational and administrative voice systems.

[1] Radomes are the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These antennas are mounted at heights of up to 120 m and range in diameter from 2–5 m. At such extreme heights, the antennas are subjected to high wind and ice loading when storms occur and must be protected. To provide this protection, the feed horns of the antennas, which are responsible for sending and receiving microwave radio signals, are covered with a flexible covering, stretched over the antenna shroud, known as the radome. These covers are made of advanced plastics known as Hypalon and Teglar that prevent the accumulation of ice and snow that could bend or break the feed horn, and do not interfere with the microwave radio signals. The white cover illustrated in Figure 1 is an example of a radome on an uninstalled antenna.

Figure 1: Microwave Antenna with Radome

Damage to radomes can occur in several ways. Exposure to wind, sun, rain, and ice causes the radomes to deteriorate over time. When the radome weakens, tears form in the fabric, as shown in Figure 2. Left unchecked, the tears quickly grow in size (Figure 3) and the material can be torn free by wind. Such tears may result in severe damage to the delicate antenna components.

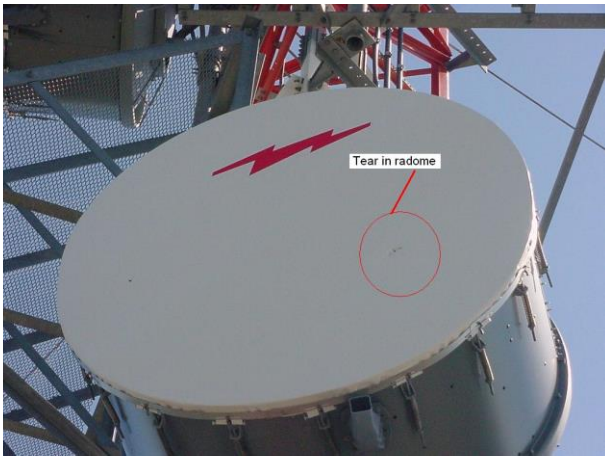

Figure 2: Tear in Radome

Figure 3: Heavily Damaged Radome

Figure 4: Missing Radome Mounts

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the hardware that hold the radome in place, as shown in Figure 4. Vandalism by the use of shotguns, rocks, or other projectiles has also occurred at sites that are accessible by road. Each of these occurrences has the potential to damage the radome and make it prone to complete failure.

There are 77 radomes throughout Hydro's system. They are installed on towers from St. John's west to Deer Lake and south to Bay d'Espoir. Figure 5 shows Hydro's Telecommunication Network.

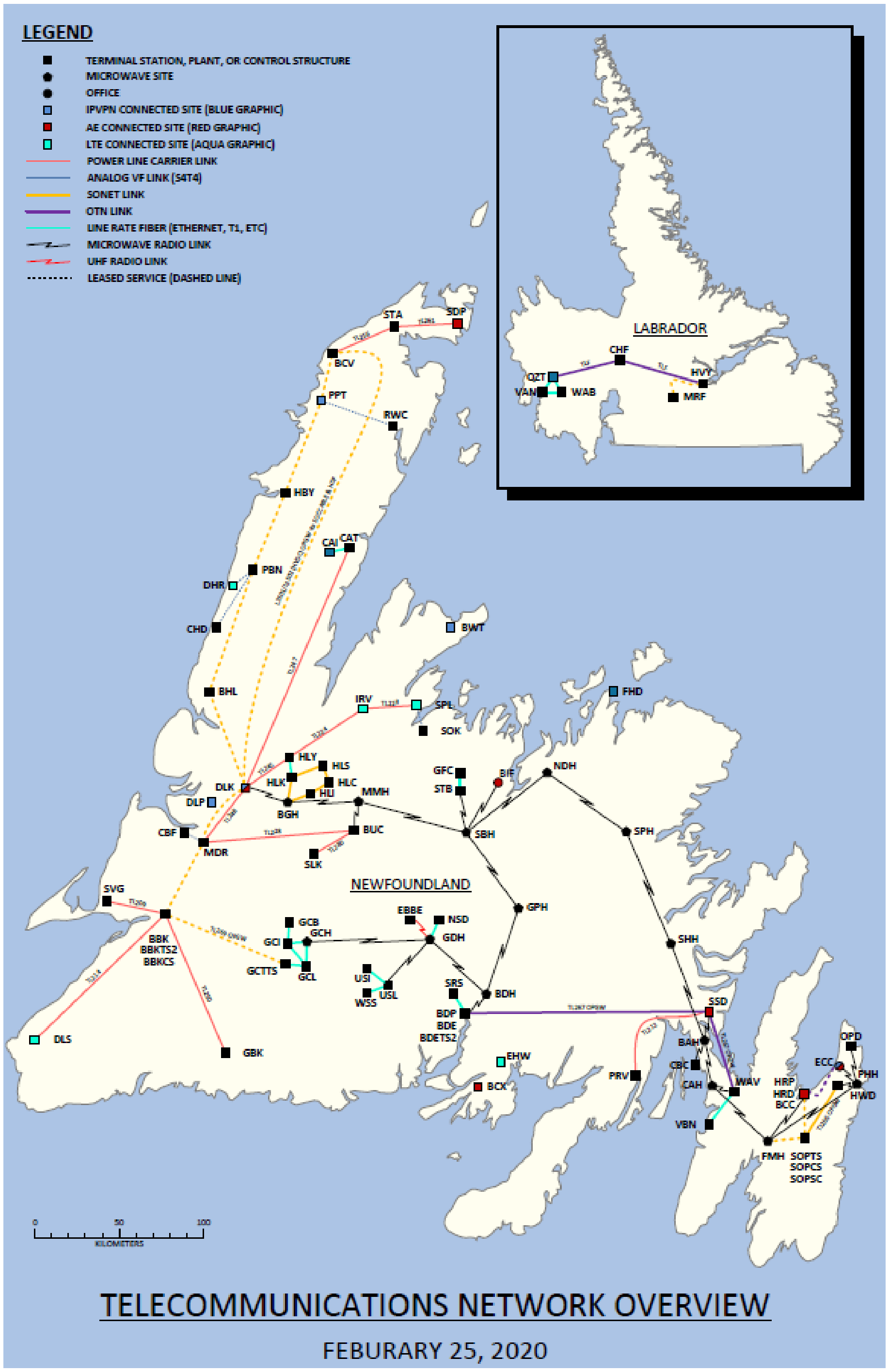

Figure 5: Telecommunications Network Including Microwave Towers

1 To avoid the logistical challenges that would be created by replacing all radomes in the same year, the replacement program is distributed over multiple years. The current schedule for the next five years is included in Appendix A.

Damaged radomes must be replaced as soon as damage is identified to ensure the integrity of the microwave system. A radome failure could result in failure of the microwave system. The impact of a microwave failure today could have a greater effect than the incident of 1996 (further discussed in Section 2.2) due to the fact that teleprotection signals, which protect transmission lines in the event of a system disturbance, are now transmitted using the microwave network. Today, protection signals for 17 of Hydro's 24 critical 230 kV transmission lines are carried on the microwave network. Therefore, a microwave failure would cause the Energy Control Centre ("ECC") to lose control of the system stations and could cause and/or extend customer outages.

2.2 Operating Experience

In the winter of 1996, a wind storm resulted in the failure of two separate radomes at the Sandy Brook Hill and Mary March Hill microwave sites which caused a significant and sustained outage to a part of Hydro's telecommunication network. Despite routine inspections, the radomes were torn in the storm and the radome material became entangled in the antenna feed horns. As a result, critical components at both sites were irreparably damaged and the antennas required replacement. Once the storm cleared and the cause of the outage was identified, antennas could not be replaced until three weeks later, due to lead times associated with material procurement and weather-related delays.

In total, the microwave radio system was out of service for approximately six weeks. During that time, temporary leased telecommunications services were procured and installed, resulting in unanticipated labour and materials costs.

There have been no other telecommunication outages caused by radome failures since the 1996 wind storm.

As a result of the costs and outage time associated with the 1996 wind storm, personnel from Hydro consulted with manufacturers to develop a proactive radome replacement plan. Based on discussions with representatives from radome manufacturers Andrew Solutions (now CommScope) and CableWave, the following replacement frequency was developed:

- CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle; and
- CommScope radomes (made of Teglar material) should be replaced on an eight-year cycle.

CommScope radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas due to the structural differences associated with each type of antenna.

3.0 Justification

Radomes have an average life of seven or eight years depending on the radome brand and must be replaced before failure. Radome failures are unacceptable as damage to microwave dishes would result in extensive telecommunications outages and costly repairs. A microwave failure would cause the ECC to lose control of the system stations and likely cause and/or extend customer outages. Loss of teleprotection capability could result in damage to Hydro's electrical equipment.

4.0 Analysis

4.1 Identification of Alternatives

Hydro considered the following options:

- Alternative 1: Deferral; and
- Alternative 2: Scheduled replacement of radomes.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Prolonged use of a radome beyond its recommended replacement date increases the likelihood of an extended telecommunications outage that would negatively impact the integrity of Hydro's energy systems. Minor radome damage cannot be repaired and can quickly result in radome failure. Deferral is not recommended.

4.2.2 Alternative 2: Scheduled Replacement of Radomes

This alternative requires replacement of radomes on a schedule determined in consultation with the manufacturers' recommendations of the useful life of the radome. Replacement of radomes occurs in advance of damage to the radomes (or, if damage is indicated on inspection, immediate replacement occurs), materially reducing the risk of damage to microwave dishes due to damaged radomes.

4.3 Proposed Alternative

Radomes should be replaced proactively based on vendor's recommendations of useful life as a failure caused by a damaged radome could have a material impact on Hydro's electrical system and Hydro's customers. Hydro believes it is prudent from both a reliability and a cost management perspective to replace these assets before they show indication of damage.

5.0 Project Description

The proposed project includes replacement of 10 radomes at various locations as shown in Appendix A. Should a damaged radome be discovered during 2022 inspections, its replacement would also be executed under this project.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	73.7	0.0	0.0	**73.7**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	80.2	0.0	0.0	**80.2**
Other Direct Costs	8.4	0.0	0.0	**8.4**
Interest and Escalation	9.5	0.0	0.0	**9.5**
Contingency	8.1	0.0	0.0	**8.1**
Total	**179.9**	**0.0**	**0.0**	**179.9**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare project plan and site visits	January 2022	February 2022
Design:		
Review tender package with contractor	February 2022	March 2022
Procurement:		
Purchase radomes	April 2022	April 2022
Construction:		
Install radomes	May 2022	September 2022
Commissioning:		
Site inspections	October 2022	October 2022
Close Out:		
Project close out	November 2022	December 2022

6.0 Conclusion

Hydro’s radome replacement program is based on operational experience and manufacturers’ recommendations and is necessary reduce the risk of outages caused by radome damage. Due to operational risks associated with the failure of corporate microwave equipment, it is necessary for Hydro to take a proactive approach to managing the risk associated with failures of microwave antenna radomes.

Appendix A

Radome Replacement Schedule

Table A-1: Site Name Abbreviations

Abbreviation	Site Name
BAH	Bull Arm Hill Microwave/Repeater
BDE	Bay d'Espoir Terminal Station
BDH	Bay d'Espoir Hill Microwave/Repeater
BFI	Bishop Falls Office
BGH	Blue Grass Hill Microwave/Repeater
BUC	Buchans Terminal Station
CAH	Chapel Arm Hill Microwave/Repeater
CBC	Come By Chance Terminal Station
DLK	Deer Lake Terminal Station
DLP	Deer Lake Passive Repeater
ECC	Energy Control Center
FMH	Four Mile Hill Microwave/Repeater
GCH	Granite Canal Hill Microwave
GDH	Godaleich Hill Microwave/Repeater
GPH	Gull Pond Hill Microwave
HRP	Holyrood Plant
HWD	Hardwoods Terminal Station
MMH	Mary March Hill Microwave
NDH	Notre Dame Hill
OPD	Oxen Pond Terminal Station
PHH	Petty Harbour Hill Microwave/Repeater
SBH	Sandy Brook Hill Microwave
SHH	Shoal Harbour Hill
SPH	Square Pond Hill
SSD	Sunnyside Terminal Station
STB	Stony Brook Terminal Station
USL	Upper Salmon Plant
WAP	Western Avalon Passive Repeater
WAV	Western Avalon Terminal Station

Table A-2: 2022 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model 3	Last Replaced
BDH	GPH	2.4 m (8')	Andrew	HP8-71D	2014
BDH	GDH	3.0 m (10')	Andrew	HP10-71D	2014
SHH	BAH (main)	2.4 m (8')	Andrew	HP8-71GE	2014
SHH	BAH (div)	2.4 m (8')	Andrew	HP8-71GE	2014
SHH	SPH (main)	3.6 m (12')	Andrew	HP12-71E	2014
SHH	SPH (div)	3.6 m (12')	Andrew	HP12-71E	2014
SPH	SHH (main)	3.6 m (12')	Andrew	HP12-71E	2014
SPH	SHH (div)	3.6 m (12')	Andrew	HP12-71E	2014
SPH	NDH (main)	3.6 m (12')	Andrew	HP12-71E	2014
SPH	NDH (div)	3.6 m (12')	Andrew	HP12-71E	2014

Table A-3: 2023 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
GPH	SBH (div)	3.6 m (12')	CW	DA12-71hp	2016
GPH	BDH	1.8 m (6')	CW	DA6-71hp	2016
SBH	GPH	3.6 m (12')	CW	DA12-71hp	2016
SBH	STB	1.8 m (6')	CW	DA6-71hp	2016

Table A-4: 2024 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	CAH	2.4 m (8')	Andrew	HP8-71D	2016
BAH	CBC	1.8 m (6')	Andrew	HP6-71E	2016
BAH	SSD	1.8 m (6')	Andrew	HP6-71E	2016
GPH	SBH (main)	3.6 m (12')	Andrew	HP12-71E	2016
GPH	BDH	2.4 m (8')	Andrew	HP8-71D	2016
SBH	GPH	3.6 m (12')	Andrew	HP12-71E	2016
SBH	MMH	3.0 m (10')	Andrew	HP10-71D	2016

Table A-5: 2025 Radome Replacements

Tower	Direction	Antenna Size	Antenna Vendor	Antenna Model #	Antenna Last Replaced
MMH	BUC	1.8 m (6')	CW	DA6-71HP	2018
PHH	FMH (main)	3.0 m (10')	Andrew	HP10-71D	2017
STB	SBH	1.8 m (6')	CW	DA6-71HP	2018

Table A-6: 2026 Radome Replacements

Tower	Direction	Antenna Size	Antenna Vendor	Antenna Model #	Antenna Last Replaced
CAH	FMH (main)	3.0 m (10')	Andrew	HP10-71D	2018
CAH	FMH (div)	2.4 m (8')	Andrew	HP8-71D	2018
CAH	BAH (main)	3.0 m (10')	Andrew	HP10-71D	2018
CAH	BAH (div)	2.4 m (8')	Andrew	HP8-71D	2018
CAH	WAP	2.4 m (8')	Andrew	HP8-71D	2018
FMH	PHH (main)	3.0 m (10')	Andrew	HP10-71D	2018
FMH	CAH (main)	3.0 m (10')	Andrew	HP10-71D	2018
FMH	CAH (div)	2.4 m (8')	Andrew	HP8-71D	2018
FMH	HRP	2.4 m (8')	Andrew	HP8-71D	2018
WAP	CAH	2.4 m (8')	Andrew	HP8-71D	2018
WAP	WAV	2.4 m (8')	Andrew	HP8-71D	2018
WAV	WAP	1.8 m (6')	Andrew	HP6-71E	2018

Replace Network Communications Equipment (2022)

Category:	General Properties – Telecontrol – Network Services
Definition:	Pooled
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

Newfoundland and Labrador Hydro's ("Hydro") communications network is vital to the day-to-day operation of employees and information systems. The administrative communications network is used to tie together users and systems, and carries voice and data communications between all significant offices, terminal stations, and generating facilities. The administrative network also provides critical communications interfaces to the Internet and the public telephone system. The goal of this project is to maintain a consistent refresh of devices used in the Hydro Communications Network. This project will replace 110 wireless access points and 1 controller device that are end-of-life and nearing end-of-support from the vendor. Devices at end-of-support are vulnerable to hardware and software defects and security threats.

2.0 Background

This project is focused on maintaining up to date network hardware. The industry standard average for network life cycle is 5 years. Hydro typically maintains network hardware for 8–12 years based on past performance and typically removes these elements from service within 1–2 years from the end-of-support date. Replacement may also be required to keep up with changes in technology to ensure maximum interoperability.

An analysis based on device criticality is performed every year to prioritize replacement of network devices. Devices in the field, such as those in small offices, would obtain a lower classification than devices that support critical network transport.

Hydro currently manages and maintains 300 wireless access points operated by a Wireless LAN Controller ("WLC") in its administrative communications network. These wireless networking devices have been deemed end-of-life since 2018. The WLC has been deemed end-of-support in 2023 and the wireless access points have been deemed end-of-support in 2024. Hydro intends to replace the wireless access points in a phased approach. In 2022, Hydro proposes the replacement of 111 wireless networking devices, 1 WLC and 110 wireless access points, with updated technology equivalents. The remaining wireless access points will be proposed for replacement through future capital budget applications such that they are all replaced prior to end-of-support in 2024.

A list of wireless networking devices to be replaced by location is provided in Table 1.

Table 1: Wireless Networking Devices to be Replaced by Location

Device	Device Location	Number of Devices
WLC	Hydro Place	1
Wireless Access Points	Hydro Place	60
	Bay d'Espoir	20
	Holyrood	20
	Bishops Falls	10

2.1 Existing Equipment

The wireless networking devices identified for replacement support administrative network connectivity for local offices, generating facilities, and terminal stations. The Hydro administrative network includes 300 wireless networking devices in various stages of their product life cycle. Devices are replaced over time as they reach the end of their maintenance agreements or as they require replacement to keep up with changes in technology to ensure maximum interoperability.

2.2 Operating Experience

Network devices in the Hydro network have been proven to be reliable and secure when properly maintained and kept up to date. Maintenance of network devices occurs on an ongoing basis. Network devices require routine updates and upgrades to ensure the devices are functional and secure. Network hardware vendors regularly release software updates to address any identified deficiencies as well as security updates. Timely security updates and patches have become increasingly critical in recent years, requiring the latest generation of devices. These updates only continue until vendors deem the devices end-of-support as per its product life cycle management and the devices are no longer attached to a valid service contract.

Hydro maintains maintenance agreements with vendors whereby the vendors provide software and security updates which are critical to operational performance. Under the current agreements, most vendors provide next business day replacement of devices that are not end-of-support as long as the device is attached to a valid service contract.

3.0 Justification

Network device vendors have a defined life cycle management process. Once vendors announce an end-of-life of a particular device they typically provide support for these devices for up to five years (end-of–support). After the device reaches the end-of-support date, customers are no longer entitled to hardware replacement or software updates which could leave these devices vulnerable to defects, security threats, and delays in replacing failed devices. This project to replace 111 wireless networking devices that are end-of-life and near end-of-support from the vendor is required to support the reliability and security of Hydro's administrative network connectivity for local offices, generating facilities, and terminal stations. Reliability and security of Hydro's administrative network is required for daily operation of the system, including the necessary communications between all significant offices, terminal stations, and generating facilities to support the electrical grid.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Replacement of identified wireless networking devices.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

The existing WLC and wireless access points have functioned since 2018 (end-of-sale) with routine software upgrades. Software upgrades are a critical component in Hydro's security plan. Without effective security updates, Hydro would not have the ability to mitigate security vulnerabilities on exposed devices. Deferring the replacement of these devices would leave Hydro vulnerable and presents an unacceptable level of risk to Hydro.

4.2.2 Replacement of Identified Wireless Networking Devices

Under this approach, Hydro would replace 1 WLC and 110 wireless access points which have been deemed end-of-life since 2018 and will reach end-of-support in 2023 and 2024, respectively. Replacing these devices with current product offerings will ensure availability of service contracts which will address any hardware and software defects and security threats.

4.3 Proposed Alternative

Hydro proposes the replacement of the identified wireless networking devices in 2022 to address risks associated with hardware and software vulnerabilities for devices which reach vendor end-of-support.

5.0 Project Description

This project will replace 110 wireless access points and 1 WLC that are end-of-life and nearing end-of-support from the vendor.

The project is divided into several phases as outlined in the project schedule. The majority of the design work will be completed by Hydro Engineering staff and implemented by the Hydro Network Services team who will maintain and operate these devices throughout their life cycle.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	82.0	0.0	0.0	**82.0**
Labour	78.0	0.0	0.0	**78.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	5.6	0.0	0.0	**5.6**
Interest and Escalation	10.8	0.0	0.0	**10.8**
Contingency	16.6	0.0	0.0	**16.6**
Total	**193.0**	**0.0**	**0.0**	**193.0**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Develop project scope statement and resource and network outage schedule	January 2022	February 2022
Design:		
Develop network drawings, design packages, and finalize bill of materials	February 2022	March 2022
Procurement:		
Prepare and award tender for new equipment	March 2022	April 2022
Construction:		
Configure and install new equipment	April 2022	May 2022
Commissioning:		
Test network connectivity	May 2022	November 2022
Close Out:		
Update as-built drawings and close out project	November 2022	December 2022

6.0 Conclusion

Hydro's communications network provides connectivity for users to access business critical systems that enable day-to-day operations. Interruption of the wireless networking devices would affect internal business operations on the administrative network. The identified devices are also required to provide network connectivity to field locations and failure of these devices would impact the ability to work safely at these locations.

Operating outside of vendor maintenance agreements presents an unacceptable level of risk to Hydro. The upgrade of network devices under this project is essential to ensuring high availability and security of administrative network operations.

Upgrade Remote Terminal Units (2022) – Various

Category:	General Properties – Telecontrol – Network Services
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") uses remote terminal units ("RTU") to remotely control its equipment and to transmit data from the equipment site to the Energy Control Centre ("ECC") at Hydro Place. Hydro's older RTUs are GE Multilin D20M++/ME models. The processor card for these models was discontinued by the manufacturer in the late 1990s but repair services continued to be provided. In 2014, electronic components became unavailable and the manufacturer is no longer repairing defective modules. Due to the discontinuation of the components and repair services, the Multilin D20 M++/ME model is considered obsolete. Hydro plans to replace the obsolete RTUs through a phased approach, with six proposed for replacement through this project. Hydro expects to propose additional RTU upgrades in future capital budget applications to avail of the advanced functionality of the newer processors and sites will be chosen based on other planned capital/operations work occurring at the same time.

2.0 Background

2.1 Existing Equipment

A critical component of Hydro's Supervisory Control and Data Acquisition ("SCADA") network is the GE Multilin D20-based RTU. This equipment is used in substations, generating stations, and other parts of the network to collect data and communicate it back to the ECC for monitoring of Hydro's system and to allow the ECC to send signals to stations to control electrical equipment. Hydro has used the D20 RTU since the early 1990s and currently has 73 units in service throughout the province.

Table 1 shows the inventory of existing D20 processor units in service.

Table 1: D20 Installed Base

GE Multilin D20 Process Model	Installed Base[1]
D20M++/ME (1990s/2000s)	31
D20MX (2013+)	42
Total	**73**

2.2 Operating Experience

The GE D20 RTU processors have proven to be reliable for Hydro and, combined with regular maintenance, have helped to minimize SCADA outages. The most recent failure, which took place in July 2014, required the use of a spare RTU to complete repairs as GE indicated that they can no longer repair defective D20M++/ME modules.

In 2014, electronic components for the D20M++ became unavailable and the manufacturer is no longer repairing defective modules. When obsolete processors fail while in-service, Hydro replaces the processor with a newer model. Hydro continues planned replacements of the obsolete processors to minimize the potential impacts on the system.

3.0 Justification

All older D20M++/ME RTU processor cards have been discontinued by the manufacturer. Due to the unavailability of electronic components, the manufacturer will no longer accept defective modules for repair. D20 processor failures will lead to forced and unscheduled upgrades of the D20 RTU, resulting in machine outages which may last multiple days and during which the ECC will not have the ability to monitor or control the affected station(s). Isolated stations would likely need to be continually staffed during this time in order to prevent extended customer outages. Upgraded processors also have enhanced monitoring, control, and security functionality.

4.0 Analysis

4.1 Identification of Alternatives

Hydro considered the following options:

- Alternative 1: Deferral; and
- Alternative 2: Upgrade six RTUs.

[1] Expected installed base as of December 31, 2021.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Deferring this project presents two primary concerns:

1) Prolonged use of the existing processors increases the risk of a prolonged SCADA outage if a processor fails; and
2) Upgrades of equipment elsewhere in a plant or terminal station typically include enhanced SCADA protocols, which cannot be utilized if they are unsupported by the RTU. Returning to the station at a later date when the RTU is upgraded to make further SCADA changes is typically not practical or cost effective. As a result, the opportunity to provide enhanced monitoring of station equipment is lost and enhanced security protocols between the ECC and the RTU cannot be implemented.

4.2.2 Alternative 2: Upgrade Six RTUs

In this alternative, the D20M++/ME processor modules in six older GE Multilin D20 RTUs will be replaced with the latest model of the D20 processor, the D20MX. Replacement with new D20MX processors will support reliability and provide increased functionality through advanced communications features, such as Ethernet and secure authentication, which are available in newer processors.

4.3 Proposed Alternative

Hydro proposes to replace six of its older D20M++/ME RTU processors to minimize the potential of a SCADA outage and to avail of the enhanced monitoring, control, and security functionality of newer D20MX processors.

5.0 Project Description

Hydro is proposing the replacement of six GE Multilin D20M++/ME RTUs with the latest model D20MX processor at terminal stations located at Indian River, Springdale, Deer Lake Power, Grandy Lake, Cow Head, and Upper Salmon. To manage program cost, Hydro may modify the location of the replacement processor modules should other network modernization projects facilitate completing RTU upgrades at the same time.

All upgrades will be fully tested in a lab environment before deployment to the field due to the critical role that the RTUs play in the monitoring and control of the network. The proposed project will be completed using Hydro personnel.

The project estimate is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	70.8	0.0	0.0	**70.8**
Labour	74.1	0.0	0.0	**74.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	9.4	0.0	0.0	**9.4**
Interest and Escalation	9.1	0.0	0.0	**9.1**
Contingency	7.7	0.0	0.0	**7.7**
Total	**171.1**	**0.0**	**0.0**	**171.1**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare project plan and site visits	January 2022	February 2022
Design:		
Complete tender package	February 2022	March 2022
Procurement:		
Purchase upgrade kits	April 2022	April 2022
Construction:		
Install upgrade kits	May 2022	September 2022
Commissioning:		
Site inspections	October 2022	October 2022
Close Out:		
Project close out	November 2022	December 2022

6.0 Conclusion

Hydro proposes the replacement of older, obsolete D20M++/ME RTU processors with D20MX processors to reduce the potential of extended SCADA outages and to avail of the enhanced monitoring, control, and security functionality of newer D20 processors. Hydro will continue to propose additional RTU upgrades in future capital budget applications so as to avail of the advanced functionality of the newer processors. Sites will be chosen based on other planned capital/operations work.

Appendix A

D20 M++/ME Locations

Table A-1: D20 M++/ME Locations

Site	Location	Site Type	Replacement Date[2]
IRV	Indian River	Plant	2022
SPR	Springdale	Terminal Station	2022
DLP	Deer Lake Power	Plant	2022
GBK	Grandy Brook	Terminal Station	2022
CWH	Cow Head	Plant	2022
USL	Upper Salmon	Plant	2022
PRV	Paradise River	Plant	TBD
PRI	Paradise River	Intake	TBD
SBK	South Brook	Terminal Station	TBD
STB	Stony Brook	Terminal Station	TBD
LOC	Local (Hydro Place)	Building	TBD
BDP-2	Bay d'Espoir 2	Plant	TBD
BDP-2R	Bay d'Espoir 2 Remote	Plant	TBD
GFL	Grand Falls	Frequency Converter	TBD
EBB	Ebbegunbaeg	Dam	TBD
GCL	Granite Canal	Plant	TBD
FHD	Farewell Head	Terminal Station	TBD
MAK	Makkovik	Diesel	TBD
VBN	Voisey Bay	Terminal Station	TBD
QTZ	Quartzite	Terminal Station	TBD
VAN	Vanier	Terminal Station	TBD
BDE-2	Bay d'Espoir	Terminal Station Two	TBD
BBK-TS1	Bottom Brook 1	Terminal Station One	TBD
BDE-PH1	Bay d'Espoir 1	Powerhouse	TBD
CAT	Cat Arm	Plant	TBD
CBC	Come By Chance	Terminal Station	TBD
DLS	Doyles	Terminal Station	TBD
HLY	Howley	Terminal Station	TBD
CAI	Cat Arm Intake	Intake	TBD
HRP	Holyrood	Plant	TBD
USC	Upper Salmon	Concentrator	TBD

[2] 2022 locations will be finalized at the beginning of the year based on other planned capital/operations work to best avail of the advanced functionality of the newer processors.

Remove Safety Hazards (2022) – Various

Category: General Properties – Administration

Definition: Pooled

Classification: Normal

Investment Classification: Service Enhancement

1.0 Introduction

This project is required to address safety hazards that are identified within Newfoundland and Labrador Hydro's ("Hydro") Safe Work Observation Program ("SWOP"). This project ensures that potential hazards that can be rectified through capital work can be efficiently completed in a timely manner.

2.0 Background

Safety hazards are identified through Hydro's SWOP by employees, contractors, and others who access Hydro facilities. Mitigation of the safety concerns can often be accomplished through an operating or procedural change, communication, or an operating budget item. In some cases, assessment of the issue and the associated recommendation concludes that a mitigation measure is a capital item. If so, a cost estimate is completed for the mitigation work, which is submitted to Hydro's Engineering and Technology Department for consideration under the Remove Safety Hazards project. These requests are reviewed and, if warranted, the funding is approved by the Senior Manager, Project Execution.

2.1 Operating Experience

In Hydro's "2020 Capital Budget Application," the Board of Commissioners of Public Utilities approved a budget of $198,600 to address safety hazards in the workplace. Table 1 lists the projects completed in 2020, which total approximately $218,400.

Table 1: Projects Completed in 2020

Location	Project Description	Cost ($000)
Holyrood Thermal Generating Station	Replace emergency eyewash and shower station	145.7
Holyrood Thermal Generating Station	Replace main gate	31.2
Various Locations	Drop stop installation on overhead monorail cranes. Locations: Upper Salmon Powerhouse, West Salmon Spillway, Cat Arm Powerhouse, and Hinds Lake Spillway	22.7
Various Locations	Journey management application for working alone	18.8
Total		**218.4**

Table 2 shows the budget and actual expenditures for years 2017 to 2021.

Table 2: Capital Expenditure History ($000)

Year	Capital Budget	Actual Expenditures
2021	199.1	-
2020	198.6	218.4
2019	197.5	210.9
2018	199.4	166.3
2017	198.6	185.9

3.0 Justification

The project is justified on Hydro's requirement to provide a safe work environment for its employees in compliance with the Newfoundland and Labrador Occupational Health and Safety Regulations, 2012:[1]

> 14. (1) An employee shall ensure, so far as is reasonably practicable, that all buildings, structures, whether permanent or temporary, excavation, machinery, workstations, places of employment and equipment are capable of withstanding the stress likely to be imposed upon them and of safely performing the functions for which they are used or intended.
>
> (2) An employer shall ensure that necessary protective clothing and devices are used for the health and safety of his or her workers.

To avoid injury or incident, Hydro has initiated the SWOP. The SWOP involves workers actively looking for safety hazards and problems that may otherwise go unnoticed which could lead to health and/or safety issues for Hydro customers, employees, contractors, and the general public. This project provides

[1] *Occupational Health and Safety Regulations*, Nfld Reg 5/12, s.14.

Hydro with the budget to address unsafe situations where capital work is identified as the solution and enables Hydro to respond quickly to address unsafe conditions rather than waiting for the normal capital budget process. These deficiencies, as reported under SWOP, need to be immediately corrected to provide a safe work environment.

4.0 Project Description

This project will allow Hydro to promptly address safety hazards as they are identified through Hydro's SWOP. A component of this program involves identifying and reporting conditions that can potentially lead to an incident or an accident. The project estimate is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	100.0	0.0	0.0	**100.0**
Labour	89.6	0.0	0.0	**89.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	10.0	0.0	0.0	**10.0**
Contingency	0.0	0.0	0.0	**0.0**
Total	**199.6**	**0.0**	**0.0**	**199.6**

As this project relates to unanticipated safety issues, no schedule is available.

5.0 Conclusion

Some safety hazards identified through Hydro's SWOP require prompt corrective actions. Hydro is proposing this project to allow for timely corrective actions that are capital in nature.

Replace Peripheral Infrastructure (2022) – Hydro Place

Category:	General Properties – Information Systems – Computer Operations
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

The Replace Peripheral Equipment project includes the replacement of multifunction printer devices (“MFD”), laser printers, a plotter, video conference units, video display projectors, meeting room moderizations, and digital signage media player controllers that have exceeded their recommended lifespan.

2.0 Background

Newfoundland and Labrador Hydro (“Hydro”) maintains peripheral equipment for document printing, scanning, and presentations at a level required to reliably function and support business processes for Hydro’s operations.

2.1 Existing Equipment

Hydro has an ongoing refresh program to maintain the reliability and performance of peripheral hardware. The current peripheral hardware replacement life cycle is five years; the life cycle has been extended to six years for large MFDs and seven years for small MFDs. Devices to be replaced under this project have been in service for a period of five or more years and have exceeded their expected useful life. Replacement parts may not be available after maintenance agreements and warranties have expired.

2.1.1 Age of Equipment or System

The decision to replace a peripheral device is based on the following criteria:

- Age and failure status;
- Availability of alternate printing;
- Availability of support;

- Product roadmap and availability of features; and
- Hydro's printing requirements and number of users.

2.2 Operating Experience

The equipment proposed for replacement was purchased in 2016 or prior. Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro's peripheral device life cycle plan of operating peripheral equipment for five years is comparable to other companies in the utility industry, including Newfoundland Power. Hydro has extended the life cycle of the MFD due to the implementation of a new service contract with the current vendor that provides equipment manitenance beyond five years without operational cost increases.

3.0 Justification

Hydro must keep its peripheral infrastructure current to adequately support its business needs. This project aims to replace equipment in a planned and consistent manner and ensures peripheral devices are available and reliable. The units scheduled for replacement in 2022 have all been in service for five or more years and their maintenance contracts and warranties have expired. If this infrastructure is not replaced and the equipment encounters a failure, Hydro could experience up to eight weeks of potential downtime from the failed piece of equipment, which would impact the efficiency of operations.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Replacement of peripheral devices.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, peripheral devices and associated systems planned for replacement in 2022 would be operated for an additional year during which time repairs would be completed and after which the devices would be replaced. After analyzing the higher maintenance costs to run at or near end-of-life, in addition to the increased technical risk of the existing equipment no longer supporting new technologies required to interface with other computer, server, storage, and network technology, this option was determined to be unacceptable due to the importance of such devices in Hydro's day-to-day operations.

When service-affecting components fail, sourcing replacement parts for devices already in service for more than five years becomes difficult and the process to upgrade or replace these systems/components could take up to eight weeks before the affected services are placed back into production. This would negatively impact the efficiency of daily operations in many facilities and is therefore not a viable alternative.

4.2.2 Alternative 2: Replacement of Peripheral Devices

Under this alternative, peripheral hardware devices including devices such as printers, page scanners, and video projectors will be replaced in 2022 to ensure reliability of services.

4.3 Proposed Alternative

Hydro is proposing the replacement of peripheral devices and components that have been in service for more than five years.

5.0 Project Description

This project will replace two small color MFDs, one plotter, two projectors, three video conferencing units, five large displays, three meeting room modernizations and one small boardroom in 2022.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	110.2	0.0	0.0	**110.2**
Labour	38.2	0.0	0.0	**38.2**
Consultant	16.3	0.0	0.0	**16.3**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	5.5	0.0	0.0	**5.5**
Interest and Escalation	6.0	0.0	0.0	**6.0**
Contingency	17.0	0.0	0.0	**17.0**
Total	**193.2**	**0.0**	**0.0**	**193.2**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project, review schedule, and create requests for proposals	January 2022	April 2022
Design:		
Conduct site visits and create project plan	February 2022	June 2022
Procurement:		
Tender and award supply and installation contract	March 2022	November 2022
Construction:		
Install hardware/software	April 2022	November 2022
Commissioning:		
Implementation and commissioning new equipment	May 2022	November 2022
Close Out:		
Project close out	September 2022	December 2022

6.0 Conclusion

To support its business processes, Hydro must maintain peripheral devices at a reliable level. If peripheral infrastructure is not kept current, there is an increased risk of failure and downtime that will negatively impact productivity. This project is a cost-effective approach to keeping Hydro's peripheral infrastructure functioning efficiently.

Hydro Command Centre Upgrade (2022) – Hydro Place

Category: General Properties – Information Systems – Software Applications

Definition: Other

Classification: Normal

Investment Classification: General Plant

1.0 Introduction

This project is being proposed to upgrade Command Centre, a component of Newfoundland and Labrador Hydro's ("Hydro") existing automated metering infrastructure solution for customer usage monitoring and billing. An upgrade is required at this time as the current version of Command Centre is nearing the end of development support; therefore, limited support will be available to Hydro should there be any issues with its performance. Additionally, Command Centre is not compatible with the newest meters that the manufacturer is selling as part of the PLX metering solution.

2.0 Background

2.1 Existing Equipment

Command Centre Version 7.1.3 is a component of Hydro's automatic meter reading solution. This centralized interface is used to transfer and manage data between collector boxes in the field which are connected to customer meters and Hydro's billing system. Meter data is fed to a collector box which Command Centre queries on a daily basis to gather and upload meter readings to the billing system. This information is required for usage monitoring and billing. The existing version of the Command Centre software is not compatible with the newest meters available from the manufacturer. As such, upgrade is required at this time to enable meter reading and billing for new meters.

2.2 Operating Experience

Command Centre has been used by Hydro for customer meter reading and billing since before 2013. The most recent upgrade was in 2016.

3.0 Justification

An upgrade is required at this time as a loss of either Command Centre's functionality or its compatibility with newer meters could negatively impact customer billing processes and accuracy of customer bills. The current version is nearing the end of development support, meaning limited support is available to Hydro. Full support of the complete package, including the application, its required infrastructure, and integrating systems, is necessary in case issues with the software arise. Such issues may include loss of functionality, loss of data, or exposure of security vulnerabilities. Additionally, the existing software is not compatible with the newest meters that the manufacturer is selling as part of the PLX metering solution. The upgrade is required to ensure Hydro's system is able to efficiently retrieve meter data which is required for billing purposes from the newest meters available.

4.0 Analysis

4.1 Identification of Alternatives

The following alternatives were evaluated:

- Alternative 1: Deferral; or
- Alternative 2: Upgrade Command Centre.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, Command Centre will continue to be operated without enhancement or update in 2022. In this scenario, vendor support will be limited, putting Hydro at risk of not being able to resolve issues that may arise. Such issues, if unresolved, could have a negative impact on customer billing.

In the event of a failure, the professional services required to provide emergency support or execution of an unplanned upgrade will be more costly and more complex due to lack of proper planning, comprehensive due diligence, and forced time constraints. The longer the upgrade is deferred, the risk of new issues occurring increases and there is more potential for unplanned costs and negative customer impact.

4.2.2 Alternative 2: Upgrade Command Centre

Under this alternative, Command Centre will be upgraded to the latest version available in 2022. Ensuring appropriate planning, budgeting, and oversight of an upgrade will support continued stability of the application for Hydro and Information Systems.

4.3 Proposed Alternative

Hydro proposes to upgrade Command Centre in 2022 to optimize the potential for vendor support and eliminate known issues for Hydro.

5.0 Project Description

This project involves the provision of professional services by the software vendor (Landis+Gyr) to upgrade the Command Centre application. Project activities include internal project management and oversight, business user testing to verify the upgrade was successful, infrastructure support, and technical professional services to be supplied by the vendor.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	26.0	0.0	0.0	**26.0**
Consultant	40.0	0.0	0.0	**40.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	3.8	0.0	0.0	**3.8**
Contingency	6.6	0.0	0.0	**6.6**
Total	**76.4**	**0.0**	**0.0**	**76.4**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Project planning	April 2022	April 2022
Construction:		
Complete software upgrade and test	May 2022	July 2022
Commissioning:		
Complete software upgrade in production	August 2022	August 2022
Close Out:		
Complete project close out activities	August 2022	August 2022

6.0 Conclusion

Command Centre is a central component of Hydro's customer usage monitoring and billing. An upgrade is required at this time as a loss of either Command Centre's functionality or its compatibility with newer meters could negatively impact customer billing processes and accuracy of customer bills.

7: Capital Projects
$200,000 to $500,000

Air Receivers Condition Assessment and Upgrades - Holyrood

Category: Generation – Thermal Plant

Definition: Clustered

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure.

This project includes a Level 2 internal inspection and engineering assessment of the eight instrument air/service air storage tanks, dryer system, associated piping, and valves. This inspection involves removing the assets from service and contracting a third-party specialist to inspect the tanks and piping using technologies such as remote operated cameras, ultrasonic thickness measurement, and guided wave measurements. Any deficiencies found during the inspection which have the potential to compromise the reliability of the system will be addressed under the project while the assets are offline for planned inspection.

2.0 Background

2.1 Existing Equipment

The Holyrood Thermal Generating Station ("Holyrood TGS") instrument and service air receivers are 17 ft. tall by 6.5 ft. diameter vertical compressed air storage tanks constructed of steel shell which is welded along its circumference. Air is compressed by the plant's compressors to 125 psi[1] with a 750 cfm[2] flow rate, and stored in the receivers. Compressed air passes through the air dryer system before moving on to valves and instrument devices including:

- Instrumentation pressure transmitters;
- Light oil igniters;

[1] Pounds per square inch ("psi").
[2] Cubic feet per minute ("cfm").

- Pneumatic control valves;
- Sealing air for heavy fuel oil burner guns and boiler observation ports to prevent boiler combustion gasses from escaping;
- Generator purging air to remove hydrogen cooling gas during a trip/shutdown;
- Air heater secondary air drive motors; and
- Maintenance shop equipment.

The air dryer system removes excess moisture from the compressed air to keep it within specifications required by the equipment.

Figure 1: Compressed Air Receiver Tanks in Powerhouse

2.2 Operating Experience

The instrument and service air system is considered a pressurized system which must follow ASME[3] Boiler & Pressure Vessel Code to ensure safe operation. Tanks are visually inspected every two years by Service NL. Despite the 40 year age of the tanks, a Level 2 internal visual and ultrasonic thickness inspection completed in 2016 indicated that the tanks were generally in good condition. Corrosion near the bottom of the tanks and piping was observed during this inspection; however, this corrosion is

[3] American Society of Mechanical Engineers ("ASME").

common for such systems and is caused by moisture condensation from the compressed air. A follow-up inspection is required to determine the rate of corrosion and to plan any interventions which may be required.

3.0 Justification

The purpose of this project is to ensure the air receivers are able to operate reliably to support Unit 3 Synchronous Condenser operation beyond 2023. The instrument and service air system is a pressurized system requiring inspection in 2022 to meet ASME Boiler & Pressure Vessel Code to ensure safe and reliable operation. Additionally, a condition assessment is required at this point to inform the rate at which corrosion is occurring, if the steel is thinning and, if so, the rate at which it is thinning, and to determine if interventions are required. The Level 2 inspection and assessment will identify any deficiencies that require immediate upgrades and be compared to the 2016 results to inform future maintenance requirements and capital planning to support reliable operation of the existing equipment.

4.0 Analysis

The instrument and service air system is considered a pressurized system which must follow ASME Boiler & Pressure Vessel standards, which require Hydro to ensure the tanks remain in safe and reliable operating condition. To comply with these requirements, Hydro must assess the condition of the tanks and undertake appropriate interventions.

4.1 Identification of Alternatives

The following alternatives have been identified for the Holyrood TGS Air Receiver Condition Assessment and Upgrades project:

- Alternative 1: Defer air receiver system inspection and upgrades; and
- Alternative 2: Inspect and upgrade air receiver system.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Defer Air Receiver System Inspection and Upgrades

The air receiver system is required for reliable operation of Holyrood TGS. Deferring this project is not acceptable based on the criticality, service life, and inspection requirements of air receiver system.

4.2.2 Alternative 2: Inspect and Upgrade Air Receiver System

Level 2 internal visual and ultrasonic inspection is a viable alternative for the Air Receiver System. Inspection results and engineering assessment will determine any immediate requirement for upgrades and inform future maintenance and capital plans. Monitoring the condition of the tanks at regular intervals ensures reliability and safety of the air receiver system.

4.3 Proposed Alternative

Inspect and upgrade the air receiver system (Alternative 2) is the proposed alternative.

5.0 Project Description

The deliverables of this project are to complete the inspection of service air storage tanks, dryer system, associated piping, and valves, including:

- Isolate, gas test, and clean air receivers;
- Perform level 2 NDT[4] inspections of the air receivers as per ASME/API[5] codes; and
- Engineering assessment and upgrades of the air receiver tanks (if required based on inspection results).

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	**2022**	**2023**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	**20.0**
Labour	199.3	0.0	0.0	**199.3**
Consultant	35.0	0.0	0.0	**35.0**
Contract Work	35.0	0.0	0.0	**35.0**
Other Direct Costs	3.0	0.0	0.0	**3.0**
Interest and Escalation	17.1	0.0	0.0	**17.1**
Contingency	27.1	0.0	0.0	**27.1**
Total	**336.5**	**0.0**	**0.0**	**336.5**

The anticipated project schedule is shown in Table 2.

[4] Non-destructive testing ("NDT").
[5] American Petroleum Institute ("API").

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Open work order and plan and develop detailed schedules	January 2022	February 2022
Engineering: Site visit and tender for level 2 NDT and engineering assessment for the air receiver tanks	March 2022	May 2022
Procurement: Patch plate and welding materials should be sourced before Inspection	June 2022	June 2022
Construction: Air receiver tanks isolation, gas testing, and cleaning for NDT inspection. Engineering assessment and repair as required based on the NDT readings	July 2022	August 2022
Commissioning: Air receiver tanks release to operations after inspection and repair, if required	August 2022	August 2022
Close Out: Close work order, complete all documentation, and complete lessons learned	October 2022	November 2022

6.0 Conclusion

The Holyrood TGS instrument and service air system is a pressurized system requiring inspection in 2022 to ensure safe and reliable operation as required under the ASME Boiler & Pressure Vessel Code. Hydro is proposing this project to ensure the air receivers are able to operate safely and reliably to support Unit 3 Synchronous Condenser operation beyond 2023.

Major Pumps Overhaul – Holyrood

Category:	Generation – Thermal Plant
Definition:	Other
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

The Holyrood Thermal Generating Station ("Holyrood TGS") is currently a critical part of the Island Interconnected System and is required to provide safe and reliable electricity. Newfoundland and Labrador Hydro ("Hydro") has committed to having the Holyrood TGS fully available for generation until March 31, 2023 to ensure reliable service for customers while the Muskrat Falls Project assets are brought online and proven reliable. Capital investment related to the generation function of the Holyrood TGS, such as the overhaul of the major pumps identified herein, is necessary to support system reliability.

This project is for the completion of a detailed inspection and overhaul of major pumps at the Holyrood TGS. The pumps proposed for inspection and overhaul are Unit 1 west cooling water pump, Unit 3 east cooling water pump, and Unit 1 north vacuum pump.

2.0 Background

2.1 Existing System

Cooling water pumps supply sea water to the condenser inside the powerhouse to cool steam after it exits the turbines. Each of the three Holyrood TGS units has two cooling water pumps which support half of the unit's generation capacity.

Vacuum pumps draw incondensable gasses from the condenser and apply a vacuum to the turbine, which is required for operations. Each of the three Holyrood TGS units have two vacuum pumps which each support the full generation capacity of the unit (i.e., the second unit is held in standby as backup). If fouling in the condenser increases throughout the operating season, both vacuum pumps may be required to support the full generation capacity of the unit.

2.2 Operating Experience

Consistent with original equipment manufacturer's ("OEM") recommendations, industry standard practice, and Hydro's experience with the assets, cooling water and vacuum pumps are on 12-year overhaul cycles.

The Unit 1 west and Unit 3 east cooling water pumps were last overhauled in 2010 and are due for overhaul in 2022 based on the established 12-year cycle. Likewise, the Unit 1 north vacuum pump was last overhauled in 2010 and is due for its next overhaul in 2022.

Hydro's operating experience has not yielded results to suggest the 12-year cycle is too frequent. During execution of the overhauls, issues are typically found which if not corrected would lead to in-service failures and forced deratings or outages. Given the pumps proposed for overhaul in this project have operated similarly over this 12-year cycle to the last, it is expected that similar wear and tear will be found.

3.0 Justification

This project is required to ensure that these major pumps are in good operating condition, contributing to the reliable operation of Units 1 and 3 and the overall reliability of the Island Interconnected System. They are due for overhaul based on the OEM-recommended cycle which, in Hydro's experience with these assets, has proven to be an appropriate time frame and appropriately balanced the cost investment required. As disassembly is required to determine whether the components of the pumps require refurbishment or replacement, the condition of these assets and their ability to continue to operate at full capacity beyond their OEM-recommended overhaul cycle is unknown. As Hydro has committed to having the Holyrood TGS fully available for generation until March 31, 2023, it is necessary to complete this project in 2022.

Parts are not readily available for these pumps due to their age; in the event of failure, reverse engineering and/or fabrication of required parts may be required which would significantly extend overhaul schedule time. Also, the pumps are quite large (particularly the cooling water pumps), possibly requiring disassembly and shipping off site for refurbishment (see Figure 1 and Figure 2). Completing the overhauls on a planned outage, with a scheduled timeslot in a pump service facility, is the preferred approach, as an unplanned forced outage has the potential for an extended forced derating of 75 MW or more possibly lasting up to several months.

Figure 1: Unit 3 South Vacuum Pump at Vendor's Shop in 2021 prior to Disassembly

Figure 2: Unit 3 West Cooling Water Pump Shipped to Pump Service Provider Shop in 2017 for Planned Overhaul

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral;
- Alternative 2: Condition-based refurbishment; and
- Alternative 3: Detailed inspection and overhaul.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Given the extension of the Holyrood TGS as a generating facility to March 31, 2023, an extension of this detailed inspection and overhaul beyond 2022 poses an unacceptable risk of failure for these major pumps. A cooling water pump failure while in operation results in a loss of 50% of the unit's generation capacity for several weeks up to several months while the pump is repaired. Hydro has determined that this alternative poses an unacceptable level of risk to reliability. Further, in-service failure of a major pump may cause additional damage to pump components, potentially resulting in additional repair costs and loss of production when compared to the cost of a planned inspection and overhaul.

4.2.2 Alternative 2: Condition-Based Refurbishment

Hydro collects some condition-related data while the pumps are in service from installed instrumentation. Additional data is collected through measurements and testing performed during annual preventive maintenance. To date, the data collected through each of these means has not proven to be adequately comprehensive to inform an accurate prediction as to whether the unit can operate reliably through to the next planned outage. Hydro has determined that, due to the limited information available, condition-based refurbishment is not a viable alternative for the major pumps.

4.2.3 Alternative 3: Detailed Inspection and Overhaul

This alternative consists of the disassembly, detailed inspection, reassembly, and recommissioning of each pump. The overhaul cycle for each pump was recommended by the OEM. Many components of these major pumps can erode, crack, or otherwise fail, leading to poor pump performance or sudden failure which may result in a collateral damage to the pump, requiring additional repair and associated costs. Therefore, detailed inspection and overhaul of major pumps are required to support the continued safe and reliable operation of the Holyrood TGS.

4.3 Recommended Alternative

As Hydro has committed to ensuring the Holyrood TGS is fully available for generation until March 31, 2023, Hydro recommends the overhaul alternative to appropriately mitigate the risk of failure of a major pump and subsequent loss of generation capacity.

5.0 Project Description

This project involves disassembly, inspection, refurbishment, and replacement of parts (as required), reassembly, and commissioning of the following:

- Unit 1 west cooling water pump;
- Unit 3 east cooling water pump; and
- Unit 1 north vacuum pump.

Disassembly and reassembly will be executed by internal resources. The refurbishment will be performed by an experienced pump service contractor. The service contractor will be engaged to do the following:

- Undertake a condition assessment of the assembly of Unit 1 west cooling water pump, Unit 3 east cooling water pump, and Unit 1 north vacuum pump through on-site inspection;
- Make recommendations and provide guidance with respect to on-site disassembly and reassembly; and
- Complete off-site refurbishment of the Unit 1 west cooling water pump, Unit 3 east cooling water pump, and Unit 1 north vacuum pump.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	1.0	0.0	0.0	**1.0**
Labour	163.3	0.0	0.0	**163.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	260.0	0.0	0.0	**260.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	24.5	0.0	0.0	**24.5**
Contingency	42.5	0.0	0.0	**42.5**
Total	**491.3**	**0.0**	**0.0**	**491.3**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare planning documentation	January 2022	February 2022
Design:		
Prepare technical specifications for the inspection, overhaul, and technical support	March 2022	April 2022
Procurement:		
Award overhaul and technical support contracts	May 2022	June 2022
Construction:		
Dismantle, inspect, and reassemble pumps	May 2022	August 2022
Close Out:		
Prepare close out documentation	September 2022	December 2022

6.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS Units 1 and 3, Hydro proposes to inspect and overhaul Unit 1 west cooling water pump, Unit 3 east cooling water pump, and Unit 1 north vacuum pump as they are due for overhaul in 2022 based on the overhaul cycle for these pumps. The project is required to maintain the acceptable operating condition of the pumps, which contribute to the reliable operation and availability of Units 1 and 3 at full generation capabilities until March 31, 2023.

Unit 3 Generator Components Condition Assessment and Miscellaneous Upgrades

Category: Generation – Thermal Plant

Definition: Clustered

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

The three major components of the Holyrood Thermal Generating Station ("Holyrood TGS") turbine generator units are the power boiler, the turbine, and the generator. The Unit 3 turbine generator is shown in Figure 1. Through the combustion of No. 6 fuel oil, the power boiler provides high-energy steam to the turbine. The turbine directly coupled to the generator provides the energy needed to turn the generator's rotor to generate electricity.

Newfoundland and Labrador Hydro ("Hydro") is proposing to replace the generator potential transformers and complete a Level 2 condition assessment on the ac[1] synchro drive, unit turning gear, and turbine generator cooling water system. These components are required to operate the Holyrood TGS Unit 3 in synchronous condenser mode.

Figure 1: Holyrood TGS Unit 3 Turbine Generator

[1] Alternating current ("ac").

2.0 Background

2.1 Existing System

The Holyrood TGS has three generating units. Unit 3 was installed in 1980 and is the only unit that has the capability to operate as a synchronous condenser. The synchronous condenser does not require any of the turbine components to operate; however, all of the generator components within the turbine generator arrangement are required for the synchronous condenser.

2.2 Operating Experience

Unit 3 has been maintained as a generator/synchronous condenser machine. In 2016, a Unit 3 rotor rewind was completed, and a Unit 3 stator rewind is scheduled for completion in 2021. These upgrades provide required maintenance to the electromagnetic components of the generating unit. In addition to these upgrades, many of the auxiliary components are original and require a level 2 condition assessment, which provides for a detailed assessment of individual components, to identify any intervention which may be required to support continued reliable operation of the generator as a synchronous condenser.

Potential transformers[2] in the Holyrood TGS have experienced two recent examples of failure. In 2019, an in-service failure on a Unit 1 potential transformer[3] required a five-day outage to allow for the replacement and commissioning of the failed potential transformer. In 2020, a Unit 3 potential transformer had a failure that caused the incorrect reading on the Holyrood TGS' output power. An incorrect reading of energy, if not observed quickly, could affect system forecasting and system generation availability.

The Unit 3 ac synchro drive system[4] is original and has reached the end of its designed useful life and requires a level 2 condition assessment to identify any further overhaul or refurbishment work to support reliable operation into the future.

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[2] The potential transformer is an electrical device used for system protection which is connected to the line voltage of the generator and a ground reference and transforms this voltage level to a lower voltage level for protection relay equipment. Unit 3 has primary terminals rated at 16 kV and has a quantity of six potential transformers measuring this voltage.

[3] Unit 1's potential transformers are of the same construction as Unit 3.

[4] The ac synchro drive system is a mechanical skid that is required to provide the mechanical energy necessary to spin the generator's rotor in synchronous condenser mode up to synchronous speed (3,600 rpm). Once the synchronous condenser reaches synchronous speed, the stator is energized and rotational speed is maintained by the magnetic field of the stator. The major components of the ac synchro drive system are a pony motor, a gear box, and a clutch.

The turning gear[5] on Unit 3 is original equipment and has reached the end of its designed useful life. Unlike Units 1 and 2, Unit 3 is operated manually through the activation of a lever; there is no remote capability. Due to the repeated manual operations of this lever, Unit 3 has experienced wear to the turning gear system and the lever is no longer working as designed. A further level 2 condition assessment is required to identify the necessary refurbishment.

Unit 3 is equipped with three turbine generator coolers,[6] which have reached the end of their designed useful life. Inspections and maintenance in Units 1 and 2 have verified advanced degradation of the cooler components and the remaining material no longer allows for extensive repairs. As the failure mechanisms and stressing factors for Unit 3 are similar, Hydro is proposing a level 2 condition assessment to determine the suitability of the Unit 3 turbine generator coolers for the continued service of the turbine generator coolers and associated pumping and piping.

3.0 Justification

If Unit 3 fails during start-up or while operating in synchronous condenser mode, it could cause voltage control concerns on the power system. Due to the age of the generator and lack of detailed condition information for the ac synchro drive, turning gear, and turbine generator coolers, detailed level 2 condition assessments are required on these Unit 3 generator components. Such assessments would inform whether future overhauls, refurbishments, or replacements will be required to support continued reliable operation of Unit 3 in synchronous condenser mode. Additionally, due to recent failures on similar potential transformers on Unit 1 and Unit 3, it is recommended to replace Unit 3 potential transformers.

[5] The turning gear system ensures the generator rotor continues to rotate even when the unit is on standby, which is required for generator cooling.
[6] The turbine generator coolers are tube-and-shell heat exchangers responsible for cooling the water that circulates through the generator’s hydrogen coolers to ensure acceptable operating temperatures for the generator.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Condition assessment and replacement of potential transformers.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Deferral of this project will result in increased risk of failure and forced outages. This could result in a synchronous condenser not operating reliably for voltage support of the transmission system; therefore, it is therefore not an acceptable alternative.

4.2.2 Alternative 2: Condition Assessment and Replacement of Potential Transformers

Due to the age of the Unit 3 generator and lack of detailed condition information for the ac synchro drive, turning gear, and turbine generator coolers, further detailed level 2 condition assessments are required to give Hydro the insight into the current state of the equipment and inform any requirements for future overhauls, refurbishments or replacements. Replacement of Unit 3 potential transformers is proposed due to the recent failures of similar potential transformers on Units 1 and 2. Hydro believes it is prudent to complete the replacement at this time as the potential transformers on Unit 3 experience similar utilization and is therefore likely to experience similar failures if left unaddressed.

4.3 Proposed Alternative

Hydro proposes the replacement of the Unit 3 potential transformers and the completion of a level 2 condition-based assessment on the Unit 3 ac synchro drive, turning gear, and turbine generator coolers.

5.0 Project Description

This is a two-year project wherein 2022 activities will largely comprise of engineering and procurement while 2023 activities will include on-site investigations, the level 2 condition assessments, installation of upgrades, and commissioning.

The specific system components to be assessed are listed below:

- ac Synchro Drive System:
  - Level 2 condition assessment on the pony motor (4,160 V, 1,600 HP, 2P), including a detailed rotor inspection, complete with mechanical NDE[7] testing; and
  - Level 2 condition assessment on clutch system.
- Turning Gear System:
  - Level 2 condition assessment of turning gear motor and gears.
- Turbine Generator Cooling System:
  - Level 2 condition assessment of the turbine generator heat exchangers, pumps, and piping; and
  - Refurbishment if found leaking or deteriorated based on the condition assessment.
- Potential Transformers:
  - Replacement with units having the same specification as the existing ones.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	**2022**	**2023**	**Beyond**	**Total**
Material Supply	76.0	0.0	0.0	**76.0**
Labour	55.4	148.7	0.0	**204.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	132.0	0.0	**132.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	8.5	30.0	0.0	**38.5**
Contingency	13.1	28.1	0.0	**41.2**
Total	**153.0**	**338.8**	**0.0**	**491.8**

[7] Non-destructive examination ("NDE").

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Planning to develop a schedule and determine the scope of project and lead time on level 2 condition assessments and procurements	January 2022	April 2022
Design:		
Design and specification for new potential transformers installation	April 2022	August 2022
Procurement:		
Tender and procure new potential transformers	July 2022	June 2023
Construction:		
Level 2 condition assessment and potential transformers replacement	April 2023	October 2023
Commissioning:		
Potential transformers and proper operation of level 2 condition assessment systems	October 2023	October 2023
Close Out:		
Project documentation close out, level 2 condition assessment reports, and equipment data	November 2023	December 2023

6.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS as a synchronous condensing facility, Hydro recommends the replacement of Unit 3 potential transformers and the completion of a level 2 condition assessment on the ac synchro drive, turning gear, and turbine generator cooling water systems associated with Unit 3. The level 2 condition assessment will inform Hydro as to the current state of the equipment so it can plan future overhauls, refurbishments, or replacements to support the continued reliable operation of Unit 3 as a synchronous condenser into the future.

Replacement of Short-Term Load Forecasting Software

Category:	General Properties – Information Systems – Software Applications
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

This project involves replacing Newfoundland and Labrador Hydro's ("Hydro") current short-term load forecasting software, Nostradamus,[1] with a service-based product that is actively supported by the software developer.

2.0 Background

Hydro uses its short-term load forecast to support the management of the power system and ensure adequate generating resources and operating reserves are available to reliably meet customer demand. Currently, a software program with modelling capabilities is used to produce a short-term (one to seven days) load forecast with an hourly time step with a time frame of seven days.

Accurate and reliable short-term load forecasting capabilities are a critical part of system operations decision making. The forecast is a critical component in determining generation reserves, unit commitment and scheduling, the ability to participate in export transactions, and performing equipment outage assessments.

Following the supply disruptions experience in 2014, the importance of accurate forecasting was noted by The Liberty Consulting Group in its report on Island Interconnected System to Interconnection with Muskrat Falls addressing Hydro which stated: "Inaccurate low forecasts hamper Hydro's ability to respond in a supply emergency, cause delayed communications to customers and reduce the ability to plan for and mitigate shortages."[2] Liberty's report went on to detail two specific recommendations tied directly to Hydro's use of the Nostradamus software program. The recommendations were as follows:

[1] The product is provided by Ventyx (an ABB Company).
[2] "Supply Issues and Power Outages Review Island Interconnected System Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland and Labrador Hydro," The Liberty Consulting Group, December 17, 2014, at p.14.

> 2.1 Provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down.
>
> 2.2. By April 30, 2015, provide the Board an assessment of the effectiveness of Nostradamus during the 2014-15 winter and the sufficiency of the model for continued future use.[3]

In accordance with recommendation 2.1, Hydro began filing reports regarding the accuracy of Nostradamus on a monthly basis, with the regulatory filing requirements subsequently adjusted to semi-annually before being adjusted to the current requirements of annual filing. Hydro's most recent report was filed on Februray 1, 2021.[4]

In accordance with recommendation 2.2, Hydro filed its response in a report titled "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro Winter 2014/2015" on April 30, 2015. In that report, Hydro stated it was ". . . confident that with regular planned training and development of the model, Nostradamus will continue to provide Hydro with the information it needs to manage the system."[5] Recent increases in the instances of unpredictable errors and issues with forecasts, further detailed in Section 2.2, have reduced Hydro's confidence that the existing software remains capable of meeting the evolving needs of the power system. Currently, the Nostradamus software package is used to forecast the hourly power system demand on a short-term basis. The accuracy and reliability of these forecasts are important to ensure that Hydro can meet the required system demand and efficiently plan and dispatch generation as required to supply system requirements, including required operating reserves. These forecasts are used to develop operating reports, including Hydro's daily Supply and Demand Status Reports which are filed with the Board of Commissioners of Public Utilities ("Board") and made available publically on the Board's website,[6] tools for use by Energy Control Centre operators, and enable Hydro to keep its stakeholders and customers informed about the status of the Island Interconnected System capability. Additionally, the forecasts also feed into the import and export market activity decision making process.

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[3] "Supply Issues and Power Outages Review Island Interconnected System Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland and Labrador Hydro," The Liberty Consulting Group, December 17, 2014, at p.34.

[4] "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro 2020 Annual Report," Newfoundland and Labrador Hydro, February 1, 2021.

[5] "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro," Newfoundland and Labrador Hydro, April 30, 2015 at p. i/21–23.

[6] Board of Commissionrs of Public Utilities, "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System Hyro System Supply and Demand Status Reports," <http://pub.nl.ca/applications/IslandInterconnectedSystem/DemandStatusReports.htm>.

2.1 Existing Equipment

Hydro currently uses software called Nostradamus to produce its short-term load forecasts. Hydro commenced usage of this product in 1998 with Version 5.2 of the software, with substantial upgrades in 2008 and 2014. The Nostradamus User Guide provides the following description of the software, stating:

> The Nostradamus Neural Network Forecasting system is a flexible neural network-based forecasting tool developed specifically for utility demand forecasting. Unlike conventional computing processes, which are programmed, neural networks use sophisticated mathematical techniques to train a network of inputs and outputs. Neural networks recognize and learn the joint relationships (linear or non-linear) between the ranges of variables considered. Once the network learns these intricate relationships, this knowledge can then easily be extended to produce accurate forecasts.[7]

The Nostradamus model is trained using a sequence of continuous historic periods of hourly weather and demand data. The model then forecasts system demand for a seven-day horizon using predictions of weather parameters. The model is used for short-term (one to seven days) load forecasting with an hourly time step. Four forecasts are created: one for the Avalon Peninsula, one for the Island Interconnected System, one for the Labrador West system, and one for the Labrador East system. The forecast is used to assist in determination of generation reserves on the Island Interconnected System, unit commitment and scheduling, and equipment outage assessments. Additionally, the forecasts are used to assist in determining transmission system reserves in Labrador, given the transmission constraints in those systems.

2.2 Operating Experience

Following the outages experienced in 2014, Hydro made significant improvements to its load forecasting process to address concerns identified during reviews of the January 2014 supply disruptions. Since that time Hydro has continued to use Nostradamus to provide its short-term load forecasts. In recent years, however, Hydro has been experiencing unpredictable errors and issues with forecasts from either its production or its development models which have been determined to be related to the Nostradamus software program.[8] Though Hydro has worked extensively with Nostradamus support on such matters when they occur, in instances Nostradamus support has concluded that the problem is within the software package itself and cannot be precisely determined or corrected.

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[7] "Nostradamus User Guide," Ventyx (an ABB Company), Release 8.2, EMDDB-0170-1405-06, May 2014.
[8] The production model is the model actively used to produce load forecasts. The development model is the model used to train the program and test functionality of modifications before the same are actively deployed in the production environment. The development model also serves as a backup to the production model.

Hydro has reported such instances to the Board as part of its annual report titled "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro." For example, Hydro noted the following occurances in its 2020 report:

> At midnight on January 1, 2020, Nostradamus stopped importing actual load data until January 3, 2020 due to some scheduled tasks deleting at the start of the New Year, resulting in a system error in the executable file. The issue was corrected on January 3, 2020 and actual load data for that time period was imported, correcting the load forecast going forward.[9]

> From January 2020 to April 2020, Nostradamus would infrequently forecast either a large increase or decrease in load which was inconsistent with expectations based on system conditions. The error would persist through weather forecast updates, pushing the erroneous value out by one hour at a time. Meetings with Nostradamus support occurred on a number of occasions and the issue was permanently fixed by manually running a forecast within the program. Nostradamus support concluded that the issue was likely due to an error in the Nostradamus program and unrelated to Hydro's system or its usage of the program. Another training exercise was completed in October 2020. Since then, the issue has not occurred.[10]

> From October 27, 2020 to October 28, 2020 some actual load data was missing from the development version of Nostradamus for an unknown reason. Correct actual load data was taken from the production version to replace the missing data for the affected hours. This did not impact the production version; therefore, there was no impact to the load forecast as used by the NLSO. The correction was made for training purposes only.[11]

Additionally, in the first quarter of 2021 there was an error in the Nostradamus program which resulted in an increased requirement for generation from the Holyrood Thermal Generating Station ("Holyrood TGS"). Hydro reported the impacts to the Board in its Quarterly Regulatory Report, which stated:

> Holyrood TGS generation above minimum was required due to an error in the Nostradamus forecasting program. Mitigating measure have been taken to help reduce the likelihood of the error occurring in the future. Costs associated with operation of Holyrood above minimum requirements during ponding transactions are reimbursed and do not impact customers.[12]

The continued use of the Nostradamus software application requires extensive support of Hydro's Resource and Production Planning team and its Operational Technology team. The Resource and

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[9] "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro 2020 Annual Report,"Newfoundland and Labrador Hydro, February 1, 2021 at p. 5/18–21.

[10] "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro 2020 Annual Report,"Newfoundland and Labrador Hydro, February 1, 2021 at p.5/22–29.

[11] "Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro 2020 Annual Report,"Newfoundland and Labrador Hydro, February 1, 2021 at p. 6/17–21.

[12] "Quarterly Summary for the Quarter Ended March 31, 2021," Newfoundland and Labrador Hydro, May 17, 2021, app. B, at p. 1.

Production Planning team are directly involved in performing extensive training of the Nostradamus model to ensure the load forecast is produced using appropriate data. While, up to this point, Hydro has been able to train and maintain the program to continue to produce a forecast with sufficient accuracy, there continues to be a number of issues occurring with the program and its implementation. In addition to erroneous forecasts which could hamper Hydro's ability to reliably plan and dispatch the power system, issues with Nostradamus also have the potential to delay the approval of planned equipment outages and could result in delayed alerts under Hydro's Advanced Notification Protocol.

Table 1 presents the number of instances in which Hydro's Operational Technology team was required to assist with matters associated with the Nostradamus software program.

Table 1: Operational Technology Assistance Requests for Nostradamus

Year	Number of Requests
2016	30
2017	49
2018	52
2019	57
2020	52
2021 YTD	31 YTD

Finally, while Nostradamus was initially developed by Ventyx Energy, it was subsequently purchased by ABB, and later became part of Hitachi-Powergrids in 2019. The most recent major software release of the Nostradamus program was of Version 8.0 in Febuary 2012. Since that time, there have been software version updates, with Hydro currently using Version 8.2.14 in its development model. In its work to implement this software version, Hydro has confirmed that issues and bugs present in its current production model continue to be observed in Version 8.2.14. The vendor has confirmed that at this time there are no active plans for a major software release (i.e., Version 9.0) which would be expected to provide an updated and enhanced offering. While operation of the current Nostradamus software continues to be supported by the vendor, the age of the software combined with the uncertainty around future development of the program increases the risk of inaccuracies in the program which may lead to a continued decrease in the reliability of the short-term load forecast.

3.0 Justification

Hydro's short-term load forecast is a critical component in its management of the power system and operational decision making. The accuracy and reliability of these forecasts are important to ensure

Hydro can meet the required system demand and efficiently plan and dispatch generation, as required, to supply system requirements, including required operating reserves. The forecast enables Hydro to keep its stakeholders and customers informed about the status of the Island Interconnected System capability. Additionally, these forecasts feed into the import and export market activity decision-making process which, if based on erroneous forecast information, can lead to negative financial impacts for Hydro and Nalcor Energy Marketing. This project supports Hydro's ability to reliably forecast and supply customer requirements and will help ensure Hydro maintains sufficient continued short-term load forecasting capability.

Hydro's proposal is based on the need to address performance issues being experienced with the existing software and the risk it poses for system operation and reliability. New software will provide additional benefits, which are outlined below; however, it is not on the basis of these additional benefits that the project is being proposed. Hydro has included the following information to provide insight into the additional benefits that can be gained.

3.1 Benefits of Transitioning to Enhanced Software

Replacement options for the Nostradamus software program have increased capabilities and flexibility. These enhanced capabilities can be used to improve the accuracy of Hydro's short-term load forecast and information gained from these enhanced capabilities can also feed into the development of Hydro's operating and planning load forecasts. Examples of the added and enhanced capabilities include:

- Development and maintenance of forecasts which include high and low forecast bounds based upon historical weather. This would allow Hydro to more accurately forecast the potential expected range of peak demand associated with both mild and severe weather conditions. This could also be extended to provide insight into this variance at a monthly level, allowing Hydro to assess how the P90[13] condition varies through the year.
- Production of longer term forecasts with various weather bounds that can assist Hydro in analyzing any potential shift in the degree to which weather impacts the Island P50[14] and P90 peaks.
- Production of forecasts with a 30-minute time step, as compared to the 1-hour time step Hydro is currently using. Migration to a 30-minute time step will increase the accuracy of the intra-

[13] A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time, i.e., there is a 10% chance of the actual peak demand exceeding the forecast peak demand).
[14] A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time, i.e., the average forecast.

hour forecast, providing Energy Control Centre operators with more granular information regarding how demand is expected to move during peak periods. Producing a forecast with a 30-minute time step will also increase the ease of producing an accurate short-term provincial load forecast, as the Labrador Interconnected System operates on Atlantic Standard Time, which is at a 30-minute offset from Island Interconnected System which operates on Newfoundland Standard Time.

- Development of accurate forecasts of Hydro's requirements that are part of the commercial agreements associated with the Lower Churchill Project.
- Production of forecasts for weather-driven variable generation sources, including wind energy. This would allow Hydro to forecast wind generation on a day-ahead basis which can then be used to help inform assessments of resource sufficiency and economic generation dispatch.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Retention of existing software program; and
- Alternative 2: Replacement of the software program.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Retention of Existing Software Program

Under this alternative, Nostradamus would be retained and continue to be used to produce the short-term load forecast. This alternative is expected to result in continued operational impacts associated with the frequent requirement for intervention to address issues being encountered in the software program itself. Such issues lend to increased inaccuracies and a decrease in reliability in the forecast. While support for the existing software remains available, the software vendor has confirmed there are currently no major releases planned for the software. Finally, Hydro notes its recent experience with unpredictable errors and issues with forecasts which have been determined to be the result of problems within the software package itself that cannot be precisely determined or corrected. As such, Hydro does not consider this alternative to be viable.

4.2.2 Replacement of the Software Program

Under this alternative, the Nostradamus software package described in Section 2.1 would be replaced with an alternative off-the-shelf service-based software program solution, written and supported by a third-party vendor. This would include engaging vendors through the request for proposals process.

4.3 Proposed Alternative

Hydro is proposing the replacement of the existing software program in 2022 given the criticality of the short-term load forecast to reliable system operations in consideration of the issues being experienced with the existing software.

5.0 Project Description

This project involves replacing Hydro's current short-term load forecasting software, Nostradamus, with an enhanced service-based product that is actively supported by the software developer.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	250.0	0.0	0.0	**250.0**
Labour	63.8	0.0	0.0	**63.8**
Consultant	75.0	0.0	0.0	**75.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	11.8	0.0	0.0	**11.8**
Contingency	38.9	0.0	0.0	**38.9**
Total	**439.5**	**0.0**	**0.0**	**439.5**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Create request for proposals and review schedules	January 2022	January 2022
Design:		
Conduct business requirements, complete detailed design, and create project plan	January 2022	February 2022
Procurement:		
Award request for proposals, secure resources, and order materials	February 2022	February 2022
Construction:		
Build software package	March 2022	June 2022
Commissioning:		
Implement, test, and commission software	July 2022	August 2022
Close Out:		
Close out project	September 2022	October 2022

6.0 Conclusion

Hydro's short-term load forecast is a critical component in its management of the power system and operational decision making. The forecast is a critical component in determining generation reserves, unit commitment and scheduling, ability to participate in export transactions, and performing equipment outage assessments.

Hydro's exsiting software program has been in use since 1998. Hydro recommends replacing the existing software program in 2022 given the criticality of the short-term load forecast to system operations in consideration of the issues being experienced with the existing software, and increased capabilities of other software packages available in the market. This alternative is an important component in ensuring Hydro can reliably and accurately forecast customer demand requirements, which is a key factor in its ability to reliably supply customers.

Upgrade Energy Management System (2022) – Hydro Place

Category:	General Properties – Information Systems – Software Applications
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") maintains the OSI Monarch Energy Management System ("EMS") used by the Energy Control Centre ("ECC") to control and monitor the provincial transmission grid and generation facilities operated by Hydro to support the operation and reliability of the electrical grid. This project proposes an upgrade to the system software for update fixes and functionality changes to the software.

2.0 Background

This project is for the continuation of updates to support proper functionality of the EMS, which is essential to the continued reliable operation of the provincial transmission grid and generation facilities operated by Hydro. The EMS provides a critical function for Hydro and the operation of the Island Interconnected System. Without a properly functioning EMS, it would not be possible to control the system remotely.

2.1 Existing Equipment

The ECC in St. John's uses the OSI Monarch Energy Management System on a 24-hour basis to control and monitor the provincial transmission grid and generation facilities operated by Hydro.

2.2 Operating Experience

The EMS has been in continuous operation since its installation in 2006 and has performed in an acceptable manner. Until 2017, the software was upgraded on an annual basis. In 2018, Hydro trialed a biennial schedule in an effort to achieve efficiencies and cost savings. However, during execution of the upgrade in 2019 (the first upgrade following a skipped upgrade year), it was determined that the deferral of 2018 work into 2019 did not result in savings. Further, the volume of work required due to the skipped year resulted in Hydro carrying forward a material portion of the work into 2020. As the work was not completed until late in 2020 and due to anticipated COVID-19-related delays, Hydro did not propose a project to upgrade the EMS in 2021. However, due to its critical role in the reliability of Hydro's electrical system, Hydro believes this project is required on an annual basis to ensure the EMS maintains optimal functionality.

3.0 Justification

The EMS provides a critical function and is essential to the continued efficient and reliable operation of the Island Interconnected System. Failure to keep this software current will put Hydro at risk of unplanned system outages that would affect the control and monitoring of the transmission grid and generation facilities.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Upgrade Energy Management System software.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, the upgrades to the EMS would be deferred by a year. Hydro's historical experience has demonstrated that annual upgrades are required to ensure the EMS functions optimally. As the most recent updates were completed at the end of 2020, deferral of this project presents an unacceptable level of risk to the performance of the EMS and, therefore, to system reliability. As such, Hydro does not consider this alternative to be viable.

4.2.2 Alternative 2: Upgrade Energy Management System Software

In this alternative, Hydro proposes to complete an upgrade of the EMS software in 2022.

4.3 Proposed Alternative

Hydro proposes upgrading the EMS in 2022.

5.0 Project Description

This project will upgrade the OSI Monarch EMS used by the ECC to control and monitor the provincial transmission grid and generation facilities operated by Hydro. The system software is upgraded on an annual basis for update fixes and functionality changes to the software.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	0	0	**0.0**
Labour	34.3	0	0	**34.3**
Consultant	0.0	0	0	**0.0**
Contract Work	223.3	0	0	**223.3**
Other Direct Costs	0.0	0	0	**0.0**
Interest and Escalation	9.3	0	0	**9.3**
Contingency	25.7	0	0	**25.7**
Total	**292.6**	**0.0**	**0.0**	**292.6**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project, review schedule, and create requests for proposals	January 2022	April 2022
Design:		
Create project plan and develop upgrade plan details	February 2022	March 2022
Procurement:		
Award supply and installation contract	April 2022	April 2022
Construction:		
Perform software upgrades	April 2022	October 2022
Commissioning:		
Implementation and commissioning new equipment	May 2022	November 2022
Close Out:		
Project close out	October 2022	December 2022

6.0 Conclusion

Hydro performs upgrades to its EMS to eliminate software bugs and increase the functionality of the software. This project is necessary to support the continued efficient and reliable operation of the Island Interconnected System. Failure to keep this software current will put Hydro at risk of unplanned system outages that would affect the control and monitoring of the transmission grid and generation facilities.

Purchase Personal Computers (2022) – Hydro Place

Category:	General Properties – Information Systems – Computer Operations
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") personnel have assigned laptop, desktop, or workstation computers to access business software applications. To support its business and maintain operational reliability for its software applications and information, Hydro must keep computing devices and accessories current.

2.0 Background

2.1 Existing System

Hydro operates and maintains approximately 530 desktop computers, 500 laptops, 50 workstations, and 40 ruggedized mobile computers. These devices are used on a daily basis by Hydro's employees in the execution of their roles and responsibilities. As such, Hydro's needs in relation to computing devices are directly impacted by evolving business needs and user requirements.

2.2 Operating Experience

At this time, Hydro is forecasting that it will need to purchase 30 desktop computers, 112 laptops, 1 workstation, and 1 ruggedized mobile computer in 2022. Additionally, Hydro is forecasting the purchase of an estimated 225 monitors for failure replacement and new computer setups. Hydro's forecast is based on numerous factors, including workforce planning, units identified for replacement based on life cycle criteria,[1] anticipated device failures, the impacts of COVID-19 on procurement and delivery timeframes, etc.; however, devices are deployed based on real-time business needs and user requirements. A degree of variance between the forecasted device requirements included in Hydro's application and actual requirements upon device deployment is to be expected.

[1] Hydro schedules replacement of desktop/workstation computers on a six-year life cycle and laptop/rugged-mobile computers on a five-year life cycle. Hydro's life cycle criteria for computing devices is similar to that of other companies, including Newfoundland Power Inc.

3.0 Project Justification

Computing devices are critical to Hydro's day-to-day operations. Devices must be reliable; therefore, they must be maintained at a level necessary to provide the required performance and capacity to effectively run business applications. If Hydro does not have access to the appropriate computing devices or if those devices are not kept current, it could be exposed to the following risks:

- Inability to install new software applications and upgrade existing applications;
- Decreased processing speed and increased potential for lost data;
- Unsupported operating systems for patches and vulnerability updates; and
- Decreased productivity.

Each of the above-noted scenarios could negatively impact Hydro's ability to efficiently perform core business functions required for the provision of safe and reliable electrical service.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

Alternative 1: Deferral; and

- Alternative 2: Purchase computer equipment.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, the purchase of computing devices would be deferred by one year. In this scenario, existing devices would continue to be used without Hydro having the ability to replace upon failure, life cycle criteria, or in response to changing business needs. Given the increased technical risk of the existing equipment no longer supporting new applications, interfaces, and other technologies required to connect and operate with power generation/distribution devices, business-applications, and related technology, this is not an acceptable alternative.

4.2.2 Alternative 2: Purchase of Computing Devices

Under this alternative, Hydro would purchase the appropriate computing devices required to meet its business needs in 2022. This option supports Hydro's ability to maintain adequate service levels for business continuity and ensure electronic business data is secure.

4.3 Proposed Alternative

Hydro proposes to purchase the computer infrastructure required to meet its business needs.

5.0 Project Description

This project estimate is based on Hydro's forecast requirements for 2022, which are 30 desktop computers, 112 laptops, 1 workstation, 1 ruggedized mobile computer, and 225 monitors. Throughout the execution stage of the project, Hydro will determine the type of device to be deployed on a case-by-case basis depending on operational and role requirements; therefore, the number of each device type acquired may vary but the overall budget and number of units is expected to remain relatively constant.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	352.7	0.0	0.0	**352.7**
Labour	30.2	0.0	0.0	**30.2**
Consultant	34.6	0.0	0.0	**34.6**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.5	0.0	0.0	**2.5**
Interest and Escalation	15.1	0.0	0.0	**15.1**
Contingency	42.0	0.0	0.0	**42.0**
Total	**477.1**	**0.0**	**0.0**	**477.1**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Create requests for proposals, schedules, and secure resources	January 2022	April 2022
Design:		
Create project plan	February 2022	June 2022
Procurement:		
Award requests for proposals and order materials	March 2022	November 2022
Deployment:		
Deploy devices	March 2022	November 2022
Close Out:		
Project close out	September 2022	December 2022

6.0 Conclusion

Computing devices are critical to Hydro's day-to-day operations. Devices must be reliable; therefore, they must be maintained at a level necessary to provide the required performance and capacity to effectively run business applications. At this time, Hydro is forecasting that it will require 30 desktop computers, 112 laptops, 1 workstation, 1 ruggedized mobile computer, and 225 monitors in 2022. The devices actually deployed will be determined by Hydro's real-time business needs and role requirements.

Upgrade Core IT/OT Infrastructure (2022) – Hydro Place

Category:	General Properties – Information Systems – Computer Operations
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") maintains back end server and storage equipment to permit Operational Technology ("OT") software applications and Information Technology ("IT") services to function in conjunction with the Energy Management System ("EMS") to support the operation and reliability of the electrical grid. This project proposes the replacement of data centre equipment such as servers and storage that are used to provide back end IT/OT services to facilitate running Hydro software applications and services.

2.0 Background

Hydro has an ongoing refresh program to maintain hardware performance. The current server and storage hardware replacement life cycle is to replace devices after five years. Devices being replaced from this budget have been in service for a period of more than five years and have exceeded the expected reliable lifespan.

2.1 Existing Equipment

Hydro's OT and IT infrastructure includes over 180 servers, 9 TB[1] of RAM, 700 TB of disk storage, and a variety of Windows and Linux operating systems. Hydro's servers and storage are used on a continuous basis and are active for the life of the equipment. These devices are used to maintain and monitor the electrical system.

2.2 Operating Experience

This budget proposal is for life cycle replacement of data centre hardware in Hydro's core IT/OT infrastructure. The equipment proposed for replacement was purchased in 2016. Industry best practice

[1] Terabyte ("TB").

is to replace servers and storage devices on a five-year life cycle. Hydro's servers and storage are used on a continuous basis and are active for the life of the equipment. Hydro has a five-year warranty on its server and storage infrastructure. After the five-year warranty period expires, the equipment is placed on a vendor maintenance program which is reviewed and renewed quarterly until the devices are replaced. To support continued reliability, Hydro's standard is to use enterprise grade hardware for EMS and applications.

3.0 Justification

This project is required to support the reliable operability of Hydro's IT and OT systems. Hydro must keep critical infrastructure current to adequately support its business needs. If this infrastructure is not replaced and the environments encounter a failure, Hydro could experience up to eight weeks of potential downtime, which would have an impact on the efficiency of operations.

The server infrastructure will be at or near end-of-life in 2022 and will need to be replaced to ensure that the infrastructure is reliable and vendor supported. The devices identified for replacement no longer have vendor support and spare parts have been discontinued. In addition, the functions and services reliant on this infrastructure are at risk as security and support patches for the operating systems and hardware are no longer available.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Replacement of servers.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, systems would be operated for one additional year beyond the planned life cycle. After analyzing the higher maintenance costs to run at or near end life, in addition to the increased technical risk of the existing equipment no longer supporting new technologies required to interface with other servers, storage, and network technology, this option was considered high risk.

The applications and systems contained within the Hydro OT server infrastructure environments are critical systems for providing monitoring and maintenance of the power grid. If key components fail, replacement parts are difficult to procure and the process to upgrade or replace could take up to eight weeks before the applications and services are placed back into production. This would impact efficiency of operations; therefore, this alternative is not viable.

4.2.2 Alternative 2: Replacement of Servers and Data Backup Equipment

Under this alternative, several components of the OT server and storage hardware which were purchased more than five years ago will be replaced. This includes devices such as data backup systems, servers, storage capacity expansion, and cabling.

Upgrading the server hardware which is at or near end-of-life is critical to support reliability. In 2022, this hardware will be at the end of the five to six year life cycle. Running the hardware past this period increases the risk that the hardware will fail and adds complexity to sourcing replacement parts. As such, Hydro proposes to upgrade core infrastructure in 2022.

4.3 Proposed Alternative

To support reliable operation of Hydro's business and continuity of day-to-day activities which rely on this infrastructure, Hydro proposes replacement of the core infrastructure components that have been in service for more than five years.

5.0 Project Description

This project involves the replacement, addition, and upgrade of hardware components related to Hydro's EMS server and storage infrastructure. In 2022, two data backup systems and five servers used by the EMS are scheduled to be replaced and the data centre's cabling and rack components will be upgraded.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	188.8	0.0	0.0	**188.8**
Labour	82.5	0.0	0.0	**82.5**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.5	0.0	0.0	**0.5**
Interest and Escalation	9.2	0.0	0.0	**9.2**
Contingency	27.2	0.0	0.0	**27.2**
Total	**308.2**	**0.0**	**0.0**	**308.2**

1 The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project, review schedule, and create requests for proposals	January 2022	April 2022
Design:		
Create project plan	February 2022	June 2022
Procurement:		
Tender and award supply and installation contract	March 2022	November 2022
Construction:		
Install hardware/software	April 2022	November 2022
Commissioning:		
Implementation and commissioning new equipment	May 2022	November 2022
Close Out:		
Project close out	October 2022	December 2022

2 6.0 Conclusion

3 Hydro must keep its server and storage infrastructure current to support the reliability of core business
4 applications and to prevent downtime that could impact operational efficiency. Hydro proposes the
5 upgrade of hardware components related to the EMS server and storage infrastructure so Hydro
6 continues to have a reliable and secure environment to support EMS information system operations.

Refresh Cyber Security Infrastructure (2022) – Hydro Place

Category: General Properties – Information Systems – Software Applications

Definition: Other

Classification: Normal

Investment Classification: General Plant

1.0 Introduction

Newfoundland and Labrador Hydro's ("Hydro") increasing reliance on information and operational systems and its expanding data networks increases exposure to security threats to Hydro's Information Technology ("IT") and Operating Technology ("OT") infrastructure. This project will refresh Hydro's cyber security tools and improve Hydro's cyber threat detection and mitigation capabilities.

2.0 Background

Hydro maintains security management software applications, IT/OT systems, and equipment to permit OT software applications and IT services to support the secure operation and reliability of Hydro's IT environments.

2.1 Existing Equipment and Services

Hydro maintains licensing and vendor support for several cyber security software programs to ensure it has the required capability to manage cyber security threat detection and remediation activities. Ensuring Hydro's servers, storage, and endpoint computer devices are protected by antivirus, intrusion-detection, and related services is vital to the reliable and secure operation of IT/OT computing environments.

2.2 Operating Experience

Hardware devices being replaced from this budget have been in service for a period of more than five years and have exceeded the expected reliable lifespan. Industry best practice is to replace devices on a five-year lifecycle. Hydro has a five-year warranty on its server and storage infrastructure. After the five-year warranty period expires, the equipment is placed on a vendor maintenance program which is reviewed and renewed quarterly until the devices are replaced.

3.0 Justification

This project is required to ensure the IT and OT security Hydro has in place is up-to-date and performing as it should.

Hydro's increasing reliance on information and operational systems and expanding data networks increases exposure to security threats to its critical infrastructure. Major risk exposures in this environment relate to operational technology security (e.g., loss of critical infrastructure stability and processing capability due to hardware/software failure or threat of virus attacks), availability of information (e.g., loss of communication across the wide area network) and risk of corporate data loss (e.g., loss of data through cybercriminal malware and attacks).

External threats to Hydro's computer systems are mitigated through the use of anti-virus tools and detection/intrusion prevention appliances. Internet access is tightly controlled and managed by security appliances and software that help reduce the risk of potential computer viruses. A serious incident involving the loss of corporate data, or access to critical business, plant or energy control systems, would result in unplanned costs to contain, investigate and remediate the incident, as well as investments to change systems or processes if required. These incidents could negatively affect financial results, reputation, customers (i.e., reliability), and the province's power grid.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Refresh cyber security infrastructure.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

If this project is deferred, it would limit the methods available to prevent or mitigate emerging cyber security risks and the processes available to prevent those cyber security risks from affecting the reliability and integrity of Hydro's OT systems.

The applications and systems contained within the Hydro OT cyber security environments monitor and manage aspects of systems which are critical for delivering applications and communications services for reporting, monitoring, and maintenance of the power grid. If key components of the security management systems fail, replacement parts are not readily available and the process to upgrade or replace could take up to eight weeks before the applications and services are placed back into production. This would negatively impact the efficiency of Hydro's operations. As such, deferral of this project is not viable as it presents an unacceptable risk to Hydro's ability to reliably operate its systems.

4.2.2 Alternative 2: Refresh Cyber Security Infrastructure

In this alternative, several components of Hydro's cyber security environments will be upgraded or replaced to maintain the required level of service. Upgrading the associated hardware that is at the end of its useful life is critical to ensure reliability of Hydro's cyber security systems. In 2022, this hardware will have exceeded the five-year production life cycle.

4.3 Proposed Alternative

Hydro is proposing the upgrade or replacement of specific cyber security IT infrastructure components which have been identified as requiring upgrades to improve security management features/capacity, as well as replacement of devices that have been in service for more than five years. If this infrastructure is not upgraded or replaced and the environments encounter a failure or do not meet the required level of coverage for security protection, Hydro could potentially experience material downtime for key services, which would have an impact on the efficiency, reliability, and security of operations.

5.0 Project Description

This project involves the replacement, addition and upgrade of software and IT/OT hardware components related to Hydro's Energy Management System ("EMS") cyber security systems and managed environments. To ensure that Hydro has a reliable and secure environment to support EMS Information System operations, each year cybersecurity components are analyzed to identify components which require upgrade, expansion, refresh, additional licensing or replacement.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	108.3	0	0	**108.3**
Labour	52.3	0	0	**52.3**
Consultant	35.3	0	0	**35.3**
Contract Work	0.0	0	0	**0.0**
Other Direct Costs	0.0	0	0	**0.0**
Interest and Escalation	6.3	0	0	**6.3**
Contingency	19.5	0	0	**19.5**
Total	**221.7**	**0.0**	**0.0**	**221.7**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project, review schedule, and create requests for proposals	January 2022	April 2022
Design:		
Conduct site visits, complete detailed design, and internal review of consultant drawings and design	February 2022	June 2022
Procurement:		
Tender and award supply and installation contract	March 2022	November 2022
Construction:		
Install hardware/software	April 2022	November 2022
Commissioning:		
Implementation and commissioning new equipment	May 2022	November 2022
Close Out:		
Project close out	October 2022	December 2022

6.0 Conclusion

Hydro's computer systems and network infrastructure require continuous protection from cyber threats. Hydro continuously evaluates its security tools and services to ensure its systems are secure. Hydro proposes this project to ensure it has adequate cyber security tools to mitigate security threats to IT/OT infrastructure and software.

Replace Battery Banks and Chargers (2022) – Various

Category:	General Properties – Telecontrol – Network Services
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") uses 48 Vdc[1] battery banks and battery chargers to power its communications equipment and ensure continuity of service in the event of a station service power loss. Hydro establishes battery bank and charger service life criteria based on performance, reliability, physical condition, and availability of support from the manufacturer.

This project consists of the replacement of the following 48 Vdc battery banks and battery charger systems:

- Hinds Lake Intake Structure;
- Hinds Lake Control Structure; and
- Hinds Lake Spillway Structure.

2.0 Background

2.1 Existing Equipment

Hydro uses 48 Vdc flooded cell battery banks and battery chargers at Hinds Lake Intake, Control, and Spillway Structures to power its Supervisory Control and Data Acquisition ("SCADA"), voice, data, and networking equipment. In particular, Hydro's Energy Control Centre ("ECC") uses SCADA communications equipment for full-time remote monitoring and control Hydro's electrical grid. This system is also used to allow control of the up-stream structures from Hinds Lake Hydroelectric Generating Station. If this communication link is lost due to a 48 Vdc power system failure, the ECC's ability to monitor and control the plant is impeded and service reliability may be affected.

[1] Volts direct current ("Vdc")

The equipment at Hinds Lake was installed in 2001 with a life expectancy of 20 years. All equipment will be at or near the end of its service life in 2021. In addition, the battery banks are showing signs of deterioration and the chargers are obsolete.

Details of the battery banks and chargers for all three sites are included in Table 1 and Table 2.

Table 1: Summary of Battery Banks

Location	Manufacturer	Model	Bank Voltage	Battery Type	Installation Date
Hinds Lake Control	C&D Technologies	KCT-270	48	Flooded Lead Calcium	2001
Hinds Lake Intake	C&D Technologies	KCT-270	48	Flooded Lead Calcium	2001
Hinds Lake Spillway	C&D Technologies	KCT-270	48	Flooded Lead Calcium	2001

Table 2: Summary of Chargers

Location	Manufacturer	Model	Voltage	Installation Date
Hinds Lake Control	Argus	RST 48/50	48	2001
Hinds Lake Intake	Argus	RST 48/50	48	2001
Hinds Lake Spillway	Argus	RST 48/50	48	2001

2.2 Operating Experience

Flooded cell battery banks are generally installed with a life expectancy of 20 years. Replacement is based on age as well as a combination of factors and results gathered through maintenance routines, as follows:

- Capacity (determined through discharge testing) must exceed 80% of manufacturer’s rating;
- Cell impedance (determined through annual testing); and
- Physical characteristics such as leaks, cracks, swelling, evidence of electrolyte crystallization, deterioration of plate condition (determined through semi-annual inspections), etc.

Battery chargers are tested as part of regular preventive maintenance routines to ensure they can meet the rated load requirements. The replacement of chargers is based on past failures of chargers of similar models, physical condition, manufacturer support, availability of spares, and service age.

The reliability of Hydro’s 48 Vdc battery banks is ensured through a comprehensive preventative maintenance program. This program includes semi-annual inspections, annual maintenance, and cell testing, as well as full discharge testing every five years. This program is in alignment with IEEE Standard 450-2010.[2]

In each of the three sites identified for replacement, inspections have revealed physical problems that indicate it is necessary to replace the battery banks. Conditions include minor leakage, cracking, swelling, severe crystallization, and plate deterioration. Additionally, each installation is at or near the 20-year lifespan generally expected for reliable operation.

As per IEEE Standard 450-2010, replacement of individual battery cells is not recommended for a battery bank at or near end of life due to incompatibility of operating characteristics of individual cells. Complete replacement of the respective battery banks is the recommended approach to ensure reliable back-up power. Table 3 summarizes the present battery bank conditions.

Table 3: Summary of Conditions – 48 Vdc Battery Banks

	Physical Condition									
Location	**Leaks**	**Cracks**	**Swelling**	**Crystallization**	**Plate Deterioration**	**High Float Voltage (cell)**	**Failure to Hold Charge**	**Cell Impedance (↑ Trend)**	**Capacity <80%**	**Age ≥ 20 years[3]**
Hinds Lake Control	✓		✓		✓					✓
Hinds Lake Intake	✓			✓	✓					✓
Hinds Lake Spillway	✓	✓		✓	✓					✓

The battery chargers at each site were installed at the same time as the respective battery banks and are designed to meet the load requirements of the communications equipment along with the charging needs of the bank. The units presently in service are considered obsolete as the Argus model RST48/50 charger unit is no longer serviceable by the original equipment manufacturer.

[2] IEEE 450-2010 "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," The Institute of Electrical and Electronics Engineers, February 25, 2011.
[3] At time of planned replacement.

3.0 Justification

This project is required for the continued reliable operation of the 48 Vdc power supply at Hinds Lake Intake, Control, and Spillway Structures. If batteries or chargers fail, sufficient power may not be available for ECC to maintain communications and control of the site and the ability for the Hinds Lake Hydroelectric Generating Station to operate may be compromised.

The equipment proposed for replacement is at or near the end of its service life. In addition, the reliability of the battery banks is compromised due to leaks, cracks, swelling, crystallization, plate deterioration, and increasing cell impedance. Further, the charger models are obsolete and no longer serviceable. As a result this project is proposed for the continued reliability of communications equipment at these locations.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Replacement of battery banks and chargers.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, Hydro would extend the service life of the C&D battery banks beyond the manufacturer’s recommended 20 years and not address the existing concerns related to the assets’ physical condition. Hydro would also continue to rely on the obsolete Alpha/Argus RST 48-50 chargers for which spare parts and manufacturer support are no longer available. Deferring this project presents two major concerns:

1) Procurement lead times are typically three to four months for battery banks and two months for charger systems. Unplanned outages to these systems would result in the ECC having no ability to monitor or control the affection station(s) until temporary solutions are put in place. An isolated station would likely need to be continually staffed to prevent extended customer outages until a replacement system is in place; and

2) Replacement would be required on an emergency basis with increased costs due to installation overtime and expedited shipments from suppliers. Extra costs would also have to be incurred for the purchase and installation of temporary banks or chargers to allow for continued operations while permanent equipment is procured and subsequently installed.

For the reasons noted above, deferral of this work is not a viable alternative at this time.

4.2.2 Alternative 2: Replacement of Battery Banks and Chargers

Under this alternative, the battery banks and chargers would be replaced based on age and condition following Hydro's established practices which have historically supported reliable service. This alternative provides sufficient time to ensure least-cost procurement and installation.

4.3 Proposed Alternative

Hydro is proposing the replacement of the three 48 Vdc battery bank and charger systems in 2022 to minimize potential reliability concerns related to a SCADA outage and additional costs associated with emergency replacements.

5.0 Project Description

This project consists of the replacement of the 48 Vdc battery banks and charger systems at Hinds Lake Intake Structure, Hinds Lake Control Structure, and Hinds Lake Spillway Structure.

The project will require engineering design, specification, and tendering of the battery banks as well as engineering design and specification of the chargers. The chargers will be purchased directly in accordance with Hydro's standard for chargers.

Construction will be completed using internal resources and would involve the removal and recycling of existing battery banks and chargers and the installation of the new battery banks and chargers.

The estimate for this project is shown in Table 4.

Table 4: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	87.0	0.0	0.0	**87.0**
Labour	105.6	0.0	0.0	**105.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.4	0.0	0.0	**2.4**
Interest and Escalation	12.1	0.0	0.0	**12.1**
Contingency	19.5	0.0	0.0	**19.5**
Total	**226.6**	**0.0**	**0.0**	**226.6**

1 The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare project plan and conduct site visits	January 2022	February 2022
Design:		
Complete battery bank and charger design and specifications, complete battery bank tender package, and complete installation tender package	February 2022	March 2022
Procurement:		
Issue purchase orders for battery banks and chargers	March 2022	April 2022
Construction:		
Install battery banks and chargers	July 2022	September 2022
Commissioning:		
Perform site inspections	July 2022	September 2022
Close Out:		
Project close out	October 2022	December 2022

2 # 6.0 Conclusion

3 The 48 Vdc equipment at Hinds Lake Intake, Control, and Spillway Structures has reached the end of its
4 service life, has issues with its physical condition, and the equipment manufacturer is no longer
5 providing replacement parts. This project is proposed to replace the batteries and chargers to support
6 reliable operation of 48 Vdc power for operation of Hydro’s communications equipment at these
7 locations.

Install Recloser Remote Control (2022–2023) – Various

Category: Transmission and Rural Operations – Distribution

Definition: Pooled

Classification: Normal

Investment Classification: Service Enhancement

1.0 Introduction

In its 2019 Capital Budget Application, Newfoundland and Labrador Hydro (“Hydro”) proposed to establish a Recloser Automation Program. At that time, the automation of 49 reclosers was prioritized based on the individual reclosers’ accumulated scores for the following six factors:

1) Number of customers serviced;
2) Site accessibility;
3) Site location;
4) Major customer serviced (e.g., mine, hospital, large generation plant, etc.);
5) Energy Control Centre (“ECC”) rotation list for load shedding; and
6) Reliability performance measure, SAIDI.[1]

Appendix A provides a description of the factors and the methodology on how the reclosers were prioritized. From 2019 to 2024, the top ten reclosers from the 2018 analysis are proposed to be automated. Following replacement of these reclosers, Hydro will assess the need to automate the remaining reclosers.

This project proposes the installation of recloser remote control at the Coney Arm and Jackson’s Arm Terminal Stations. This includes the following reclosers:

- Coney Arm Terminal Station: CA1-R1; and
- Jackson’s Arm Terminal Station: JA1-R1, JA2-R1.

[1] System Average Interruption Duration Index (“SAIDI”).

Recloser automation allows the ECC to remotely de-energize and re-energize the feeders, enabling line crews to focus on the on-site issues and reduce the duration of outages. It also allows more cost effective operations by reducing the number of truck rolls required in support of contractors and collection of maintenance data.

2.0 Background

2.1 Existing Equipment

Reclosers are installed on distribution lines to interrupt fault current caused by either temporary or permanent electrical faults to the distribution systems. Reclosers are also used as a means to disconnect power to a distribution line for the purpose of maintenance and troubleshooting activities. This switching can be conducted manually by personnel at the recloser or remotely by ECC personnel in St. John’s if the recloser is connected to Hydro’s Supervisory Control and Data Acquisition (“SCADA”) system.

Site accessibility, site location, and presence of a major customer are the largest factors contributing to the ranking of the Coney Arm Terminal Station and Jackson’s Arm Terminal Station reclosers. In terms of site accessibility, the Coney Arm Terminal Station requires access by helicopter when snowfall levels are high and both the Jackson’s Arm Terminal Station and Coney Arm Terminal Station are approximately 150 km from the nearest line depot at Springdale. These accessibility concerns can increase site access times, especially in inclement weather, which could increase the customer power outage duration. The potential impact related to the Coney Arm Terminal Station recloser is made greater by fact that availability of the Cat Arm Hydroelectric Generating Station could be compromised by the inability to remotely operate the recloser on Line 1, which is an alternate source of station service to the generating station.

Additionally, both the Coney Arm Terminal Station and the Jackson’s Arm Terminal Station reclosers are located at terminal stations. An outage to a recloser at a terminal station would have a more widespread impact than an outage at a downstream substation or an individual downstream line which is fed from a terminal station.

2.2 Operating Experience

The Coney Arm Terminal Station recloser CA1-R1 and the Jackson's Arm Terminal Station reclosers JA1-R1 and JA2-R1 are not remotely controlled by the ECC. Presently, these reclosers can only be operated locally by personnel at the terminal stations.

For reclosers which are not connected to the SCADA system, once a distribution line failure is identified, personnel must first travel to the nearest recloser to operate the appropriate device to enact safe working procedures and then return to the failure location to perform repairs. Once the repair has been made, personnel must travel back to the recloser to restore power to customers. The travel time required by personnel to operate reclosers increases the customer power outage duration. The effect on outage duration can be significant due to the large geographic areas these lines cover. Often, travel time back and forth to recloser sites can exceed the length of the actual repair. Automation of reclosers in terminal stations eliminates the need for line crews to travel back to the terminal station to re-energize the line since this will be done through the SCADA system.

3.0 Justification

This project is a continuation of the Recloser Automation Program introduced in the 2019 Capital Budget, to install recloser remote control on reclosers identified as high priority.[2] Hydro's planned work in 2022–2023 will reduce outage durations experienced by Coney Arm and Jackson's Arm customers by reducing crew travel time associated with troubleshooting and repair activities related to the operation of the recloser.

Using the priority ranking method included in Appendix A, the Coney Arm Terminal Station recloser (CA1-R1) obtained a score of 275 and the Jackson's Arm Terminal Station reclosers (JA1-R1 and JA2-R1) both obtained scores of 270. This ranking establishes these reclosers as the next units that Hydro proposes to automate.

Table 1 summarizes the scores for each of the proposed reclosers.

[2] Recloser remote control prioritization methodology presented in Appendix A.

Table 1: Summary of Scores for Proposed Reclosers

Factors	CA1-R1	JA1-R1	JA2-R1
Number of Customers	1	3	3
Site Accessibility	11	3	3
Site Location	5	5	5
Major Customer Served	5	1	1
ECC Rotation List for Load Shedding	1	3	3
SAIDI	1	2	2
Total Score[3]	**275**	**270**	**270**

In addition, the automation of reclosers in areas that are difficult to access could result in cost savings to Hydro in two ways. First, when a pole setting contractor is scheduled to perform work on a Hydro distribution line, the current process involves a Hydro line crew travelling to the recloser location to place the recloser in "non-reclose" mode so that the pole can be installed safely near a live line. Although every effort is made to consolidate work in remote areas, there are times when trips are required to simply enable and subsequently disable the "non-reclose" operation. These trips could be eliminated if the recloser was remotely operated. Second, Hydro monitors the performance of reclosers on a monthly basis, and this performance monitoring often requires dedicated travel to the recloser site to record readings. Remote communications capability would give Hydro the ability to import monthly maintenance and performance data over the communications link and reduce travel requirements.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Installation of recloser remote control.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this approach, Hydro crews will continue to travel to the Coney Arm and Jackson's Arm terminal station reclosers for any troubleshooting and repair activities related to the operation of the reclosers resulting in longer customer outage durations than if the reclosers could be operated remotely by the

[3] Total score is the product of the scores for each factor.

ECC. In addition, Hydro crews will continue to have to travel to the recloser locations to support contractors setting poles close to live distribution lines. Hydro will continue to not have the ability to collect recloser data remotely.

4.2.2 Alternative 2: Installation of Recloser Remote Control

Under this approach, Hydro would automate the reclosers at Coney Arm Terminal Station and Jackson's Arm Terminal Station. Automation of these reclosers will reduce the requirement for crews to travel to the Coney Arm and Jackson's Arm terminal stations, reducing outage durations to customers. The automation of reclosers also enables potential cost savings associated with reduced travel required to accommodate contractors and gather monthly recloser performance data.

4.3 Proposed Alternative

Hydro proposes the installation of recloser remote control at Jackson's Arm Terminal Station and Coney Arm Terminal Station. This includes the following reclosers:

- Coney Arm Terminal Station: CA1-R1; and
- Jackson's Arm Terminal Station: JA1-R1, JA2-R1.

5.0 Project Description

The scope of work for this project includes:

- Purchase and installation of new communications infrastructure at Coney Arm Terminal Station and Jackson's Arm Terminal Station as there is currently no communications infrastructure available at these terminal stations;
- Purchase and installation of a new recloser at Coney Arm Terminal Station as the existing recloser does not have communications capability;
- Configuration of reclosers at Coney Arm Terminal Station and Jackson's Arm Terminal Station for remote control and data collection capability by ECC; and
- Configuration and commissioning of computer systems in the ECC to communicate with the reclosers at Coney Arm Terminal Station and Jackson's Arm Terminal Station.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	86.0	0.0	0.0	**86.0**
Labour	52.7	103.1	0.0	**155.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	11.8	16.5	0.0	**28.3**
Interest and Escalation	9.1	17.5	0.0	**26.6**
Contingency	15.0	12.0	0.0	**27.0**
Total	**174.6**	**149.1**	**0.0**	**323.7**

1 The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan, develop, and maintain detailed schedules	February 2022	September 2023
Design:		
Design system, develop graphics, and develop alarms/SOE[4] list	February 2022	May 2023
Procurement:		
Order all materials	February 2023	May 2023
Construction:		
Install relays, cabinet, run cables, and modifications to assorted protection for alarms/SOE	June 2023	August 2023
Commissioning:		
Confirm operation of system and all values appearing on the Energy Management System web page	September 2023	September 2023
Close Out:		
Complete all documentation, drafting of as-built drawings, and close work orders	September 2023	October 2023

2 6.0 Conclusion

3 The installation of recloser remote control at Coney Arm Terminal Station and Jackson's Arm Terminal
4 Station will improve the reliability of the Coney Arm and Jackson's Arm distribution systems by
5 permitting remote operability of the reclosers, which will reduce outage duration time by eliminating
6 the requirement for line crews to travel back and forth to the reclosers when repairing line damage.

[4] Sequence of Events

Additionally, it will result in cost savings due to reduced travel requirements for manual operation of the recloser.

Appendix A

Recloser Automation Priority List and Methodology

Methodology to Determine Priority for Recloser Automation

There are six factors considered in the prioritization of recloser automation as shown in Table A-1. Each of the six factors has a number of levels to indicate the impact of that factor on the distribution system. To evaluate a recloser for automation, Hydro determined a score for each of the six factors. The total overall score assigned for the recloser is the product of each of the factor's individual scores.

Table A-1: Factors Considered in Prioritizing Recloser Automation

Factor 1: Number of Customers Serviced

Level	Definition	Score
1	< 100	1
2	< 500 Customers	3
3	< 1,000 Customers	5
4	> 1,000 Customers	7

Factor 2: Site Accessibility

Level	Definition	Score
1	Road Access with No Difficulty	1
2	Road Access with Minor Difficulty	3
3	Road Access with Moderate Difficulty	5
4	Road Access with Major Difficulty	7
5	Access by Ferry	9
6	Access by Airplane	11

Factor 3: Site Location of Recloser

Level	Definition	Score
1	Line	1
2	Substation	3
3	Terminal Station	5

Factor 4: Major Customer Serviced

Level	Definition	Score
1	No	1
2	Mine, Hospital, Large Sawmill, Small Generation Plant	3
3	Large Generation Plant	5

Factor 5: Feeder Included in Energy Control Center Rotation List for Under Frequency Trips[1]

Level	Definition	Score
1	No	1
2	Yes	3

Factor 6: Reliability Performance Measure, SAIDI Value excluding Loss of Supply, Schedule Power Outage and Customer Request[2]

Level	Definition	Score
1	< 5	1
2	< 10	2
3	< 15	3
4	< 20	4
5	< 25	5
6	< 30	6
7	< 35	7
8	< 40	8
9	< 45	9
10	< 50	10
11	> 50	11

Table A-2 provides a list of Hydro's reclosers ranked from highest to lowest priority for automation.

Table A-2: Recloser Priority List

Rank	Distribution System	Location	Recloser	Total Score	Program Year
1	Rocky Harbour	Terminal Station	RH2-R1	405	2019–2020
2	Hampden	Terminal Station	HA1-R1	405	2020–2021
3	Upper Salmon	Recloser Station	B1L1	275	2020–2021
4	Coney Arm	Terminal Station	CA1-R1	275	2022–2023
5	Jackson's Arm	Terminal Station	JA2-R1	270	2022–2023
6	Jackson's Arm	Terminal Station	JA1-R1	270	2022–2023
7	Bottom Waters	Burlington Substation	BU4-R1	225	2023–2024
8[3]	Rocky Harbour	Terminal Station	RH1-R1	150	2019–2020
9	Main Brook	Terminal Station	MB1-R2	150	2023–2024
10	Conne River	Terminal Station	CR1-R1	135	
11	Parson's Pond	Terminal Station	PP1-R1	135	
12	South Brook	Robert Arm Substation	SB7-R2	126	
13	Monkstown	Paradise River TS	L58T1	125	

[1] Hydro has a set of feeders that may be shed for under frequency trips so as to maintain electrical system stability.
[2] This is the SAIDI value before recloser automation.
[3] Previous Recloser Priority List included Farewell Head FH1-R3 as #8. Upon further review, this recloser was removed from the program.

Rank	Distribution System	Location	Recloser	Total Score	Program Year
14	Farewell Head	Fogo Island Substation	F06-R1	108	
15	Bay d'Espoir	Terminal Station	BD1-R1	105	
16	South Brook	Triton Substation	TR5-R1	90	
17	Bottom Waters	Feeder L3	BW3-R2	90	
18	English Harbour West	Feeder L1	EH1-R2	90	
19	Glenburnie	Terminal Station	GL1-R1	90	
20	Glenburnie	Terminal Station	GL2-R1	90	
21	Bottom Waters	Feeder L1	BW1-R4	81	
22	Bottom Waters	LA Scie Substation	LS7-R1	81	
23	Farewell Head	Change Island Substation	CH3-R1	81	
24	Holyrood	Terminal Station	HR1-R1	75	
25	Roddickton	Feeder L1	R01-R3	60	
26	Farewell Head	Fogo Island Substation	F05-R1	60	
27	Upper Salmon	Feeder L1	US1-R2	55	
28	Bottom Waters	Brent's Cove Substation	BW3-R3	54	
29	Fleur-de-Lys	Recloser Sub	FL1-R2	54	
30	St. Anthony	Cook's Hr. Substation	CH7-R1	54	
31	Bottom Waters	Feeder L2	BW2-R3	45	
32	Wiltondale	Terminal Station	WD1-R1	45	
33	South Brook	Feeder L4	SB1-R4	30	
34	Barachoix	Feeder L4	BA4-R2	30	
35	St. Anthony	Feeder L1	SA1-R3	30	
36	Farewell Head	Fogo Island Substation	F04-R1	27	
37	Bay d'Espoir	Terminal Station	BD2-R1	25	
38	Bay d'Espoir	Terminal Station	BD3-R1	25	
39	Bottom Waters	Feeder L2	BW2-R2	18	
40	Fleur-de-Lys	Feeder L1	FL1-R1	18	
41	Barachoix	Feeder L1	BA1-R2	18	
42	King's Point	Feeder L1	KP1-R2	18	
43	Bay d'Espoir	Feeder L1	BD1-R2	15	
44	Grandy Brook	Burgeo Substation	BU3-R1	9	
45	Grandy Brook	Burgeo Substation	BU2-R1	9	
46	Hawke's Bay	Feeder L3	HB3-R2	5	
47	Bay d'Espoir	Feeder L1	BD1-R3	3	
48	Grandy Brook	Burgeo Substation	BU4-R1	3	

Upgrade Fuel Storage Tanks (2022) – Mary's Harbour

Category:	Transmission and Rural Operations – Generation
Definition:	Other
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

The Mary's Harbour Diesel Generating Station contains four diesel generating units with a total installed capacity of 2,540 kW. The diesel generating station is the sole generation source for the community of Mary's Harbour. The bulk fuel storage system in Mary's Harbour consists of two 314,000 litre vertical fuel storage tanks. Newfoundland and Labrador Hydro's ("Hydro") asset management practices[1] require that diesel generating station vertical fuel storage tanks undergo an internal inspection on a ten-year cycle. The tanks in Mary's Harbour were originally due for inspection in 2022; however, Hydro's evaluation of alternatives has confirmed that upgrading the bulk fuel storage system is the least-cost option and is appropriate at this time.

2.0 Background

2.1 Existing Equipment

Prior to the completion of the Trans Labrador Highway, Mary's Harbour was an isolated community and fuel delivery was completed by marine tanker. As the formation of sea ice prevented marine vessel winter access to Mary's Harbour, the fuel storage capacity requirements were based on the need to ensure adequate fuel supply for the diesel generating station until the dissipation of the ice in the spring. At the time, the bulk fuel storage system was comprised of three 68,000 litre horizontal tanks and two 314,000 litre vertical storage units. Following the completion of the Trans Labrador Highway in 2002, fuel delivery to Mary's Harbour transitioned from marine tanker to truck delivery. The ability to avail of more frequent fuel deliveries by road reduced the fuel storage requirement.

[1] As part of its ongoing asset management strategy, Hydro has formalized its tank inspections into a coordinated program. The program uses the tank inspection procedures, outlined by the American Petroleum Institute ("API"), as the basis for this standardized approach. Regular cleaning and inspection of its fuel storage tanks ensures Hydro's compliance with the terms and conditions, as outlined in the Certificate of Approval issued by the Department of Environment and Climate Change.

In 2009, the three horizontal tanks had exceeded their service life. Given the reduced site storage capacity requirement, Hydro did not replace the expired horizontal tanks; instead, they were removed from service.

2.2 Operating Experience

The two 314,000 litre vertical fuel storage tanks last underwent an internal inspection in 2012 and are due for inspection in 2022. The tanks have performed well throughout their service life; however, based on Hydro's experience from recent inspections of similar tanks, it is anticipated that the 2022 inspection will determine that a number of repairs will be required to extend the service life of these assets.

3.0 Justification

The Mary's Harbour Diesel Generating Station is the sole source of generation for the community. Hydro must ensure that its bulk fuel storage system is maintained in a condition to operate reliably and serve the fuel storage requirements for the Mary's Harbour Diesel Generating Station.

The existing tanks are due for inspection in 2022 and, based on recent inspections of similar tanks, it is expected that they will need to undergo repairs to extend their service life. Following the completion of the southern Labrador road network, fuel delivery by truck became possible and has proven to be reliable throughout the winter period. As such, the existing tanks provide an excess of fuel storage capacity. Given the change in operational requirements, Hydro felt it was prudent to conduct an analysis of its bulk site fuel storage requirements for the Mary's Harbour Diesel Generating Station. This analysis was used to identify the least-cost alternative to ensure that the bulk fuel storage system remains in a reliable operating condition and is able to satisfy the fuel storage requirements for the Mary's Harbour Diesel Generating Station.

4.0 Analysis

Vertical fuel storage tanks are typical in locations where substantial fuel storage capacity is required; however, Mary's Harbour no longer requires significant bulk storage. An analysis by Hydro concluded that the current 628,000 litres of storage in the community is not required. It was determined that three 60,000 litre horizontal fuel tanks, with a usable storage of approximately 54,000 litres per tank, will satisfy Hydro's Rural Isolated System Generation Planning Criteria by providing a minimum of three weeks of fuel storage for the community. A review was conducted to determine the least-cost option for the Mary's Harbour bulk fuel storage.

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral of the inspection/upgrade;
- Alternative 2: The completion of an internal tank inspection of the vertical fuel storage tanks and the implementation of any repairs identified during the inspection; and
- Alternative 3: Replacement of the two 314,000 litre vertical fuel storage tanks with three 60,000[2] litre horizontal fuel storage tanks, with a total usable storage of approximately 162,000 litres.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral of the Inspection/Upgrade

Alternative 1 consists of deferring the inspection of the interior of the vertical tanks or any work that would be an appropriate substitute to the inspection. This alternative is not acceptable as it would violate Hydro's requirements under the terms and conditions, as outlined in the Certificate of Approval issued by the Department of Environment and Climate Change, and impose unacceptable reliability and environmental risks associated with potential spill or other failure resulting from continued operation of tanks past the inspection timeframe.

4.2.2 Alternative 2: Inspect and Refurbish Existing Vertical Tank

Alternative 2 consists of completing internal tank inspections and implementing any repairs identified as necessary to address the findings of the inspection. Pricing for cleaning and inspecting the tanks were derived from the completion of similar work on other vertical fuel storage tanks.[3] While the nature and extent of the repairs that the tanks might require is unknown until the inspection is completed, findings from recent inspections of similar tanks were used to develop an estimate of the cost of repairs for the tanks located in Mary's Harbour.

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[2] Three 60,000 litre storage tanks were selected as they provide the required site storage capacity and provide greater operational flexibility should the tanks be repurposed at a future date.

[3] Hydro completes tank cleaning and inspections at its rural generation sites in accordance with its tank inspection program. Tendered prices for cleaning and inspection projects in Makkovik, Rigolet, and Black Tickle were referenced to develop the estimate for this alternative.

4.2.3 Alternative 3: Install Horizontal Tanks

Alternative 3 consists of replacing the two existing 314,000 litre vertical fuel storage tanks with three 60,000 litre horizontal storage tanks. The cost estimate for the procurement and installation of the horizontal fuel storage tanks was developed using recent tendered prices for similar tank replacement projects. The analysis also considered the elimination of maintenance, inspection, and future refurbishment costs associated with the existing secondary spill containment system utilized by the vertical tank, as the horizontal tanks do not require this infrastructure.

4.3 Proposed Alternative

A cost-benefit analysis with a study period of ten years was completed. This study period considered Hydro's planned construction of a regional diesel generating station to interconnect communities on the south coast of Labrador. Under the current planning scenario, Mary's Harbour will be interconnected in 2030. Upon completion of the interconnection, the Mary's Harbour Diesel Generating Station will be decommissioned.

The horizontal tanks in Alternative 3 are assumed to have a service life of 30 years. It is therefore possible that these tanks will be repurposed following the decommissioning of the Mary's Harbour Diesel Generating Station and the transfer of its load to the regional facility.

Alternative 3 was determined to be the least-cost option. A summary of the results of the analysis are shown in Table 1.

Table 1: Cost-Benefit Analysis Summary Table ($)

Alternatives	Net Present Value ("NPV")	NPV Difference between Alternative and the Least-Cost Alternative
Alternative 2: Inspect and Refurbish Vertical Tanks	721,740	125,583
Alternative 3: Install Horizontal Tanks	596,157	0

5.0 Project Description

The scope of work includes the following:

- Purchase and installation of three new 60,000 litre double-wall, vacuum sealed, horizontal fuel storage tanks; and

- Connection of the new horizontal tanks to the fuel pipe distribution system.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	198.0	0.0	0.0	**198.0**
Labour	86.9	0.0	0.0	**86.9**
Consultant	31.2	0.0	0.0	**31.2**
Contract Work	106.1	0.0	0.0	**106.1**
Other Direct Costs	8.5	0.0	0.0	**8.5**
Interest and Escalation	25.3	0.0	0.0	**25.3**
Contingency	43.1	0.0	0.0	**43.1**
Total	**499.1**	**0.0**	**0.0**	**499.1**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Budget review, scope statement, schedule, and risk assessment	January 2022	March 2022
Design:		
Detailed design and preparation of tender package	April 2022	April 2022
Procurement:		
Prepare specification and requisition	March 2022	April 2022
Fabrication and delivery of fuel tanks	April 2022	July 2022
Construction:		
Completion of fuel tank installation	July 2022	August 2022
Close Out:		
Project completion, interest cut off, and lessons learned	September 2022	December 2022

6.0 Conclusion

The existing vertical fuel storage tanks for the Mary's Harbour Diesel Generating Station were scheduled for inspection in 2022. A change in the mode of fuel delivery has reduced the site fuel storage requirement for Mary's Harbour. A cost-benefit analysis determined that replacement of the vertical storage tanks with horizontal tanks is more economical than proceeding with the continued use and ongoing refurbishment of the vertical storage tanks.

Hydro proposes to replace the existing vertical storage tanks with horizontal fuel storage tanks to ensure reliable fuel storage at Mary's Harbour Diesel Generating Station.

Additions for Load (2022) – Mary's Harbour Service Conductor

Category:	Transmission and Rural Operations – Generation
Definition:	Clustered
Classification:	Normal
Investment Classification:	System Growth

1.0 Introduction

Load growth in an isolated system increases the peak demand and overall energy requirements on that system. As the load on the system increases, equipment such as service conductors can become overloaded.

The electrical infrastructure in the Mary's Harbour isolated system consists of a diesel generating station coupled with a substation and distribution system that together supply electricity to both communities of Mary's Harbour and Lodge Bay. Mary's Harbour is located in southern Labrador as per Figure 1.

Figure 1: Mary's Harbour, Labrador

In September 2019, Newfoundland and Labrador Hydro ("Hydro") received a preliminary service request for a new large customer in Mary's Harbour. This request was revised in March 2020 and indicates that the facility is expected to be in operation during the summer of 2021, and will have a peak demand of 507 kW during the summer and a non-summer peak load of 192 kW.

Due to load growth associated with this request, the Mary's Harbour Diesel Generating Station main service conductor is expected to exceed its rated capacity during the summer of 2021. Hydro's long-term planning criteria required replacement of equipment when ratings are exceeded, as overloaded equipment is at greater risk of failure, reducing system reliability.

Hydro has assessed the impact of operating the service conductors above rated load in the short term and is not concerned with the operation of the existing service conductors through 2022, until replacement in 2023; however, replacement in 2023 is required to ensure reliability and capacity of the system in the long term.

2.0 Background

2.1 Existing Equipment

The Mary's Harbour Diesel Generating Station consists of four diesel generating units[1] with a combined capacity of 2,540 kW. This diesel generating station serves the entire coastal Labrador towns of Mary's Harbour and Lodge Bay. Mary's Harbour has population of approximately 340 residents[2] and the town of Lodge Bay has approximately 70 residents.[3]

Three of the diesel generators that are located inside the diesel generating station engine hall are connected to the diesel generating station's substation transformer via the main service conductor. The main service conductor currently installed consists of four parallel runs of 313 MCM cable per phase.

2.2 Operating Experience and Historical Load Information

The Mary's Harbour system is a summer peaking system that has been experiencing consistent load levels over the past seven years since the opening of a large fish plant in 2013. Since then, the energy requirement has slightly decreased year over year, while the peak load remains consistent. The historic

[1] Unit 2090 is a mobile generator that is connected directly to the substation transformer primary and bypasses the main service conductor.
[2] 2016 Census data retrieved from Newfoundland and Labrador Community accounts.
[3] "Our Communities," Southern Labrador <http://www.southernlabrador.ca/home/communities.htm>.

peak load and energy consumption[4] of the Mary's Harbour system from 2010 to 2020 is shown in Figure 2.

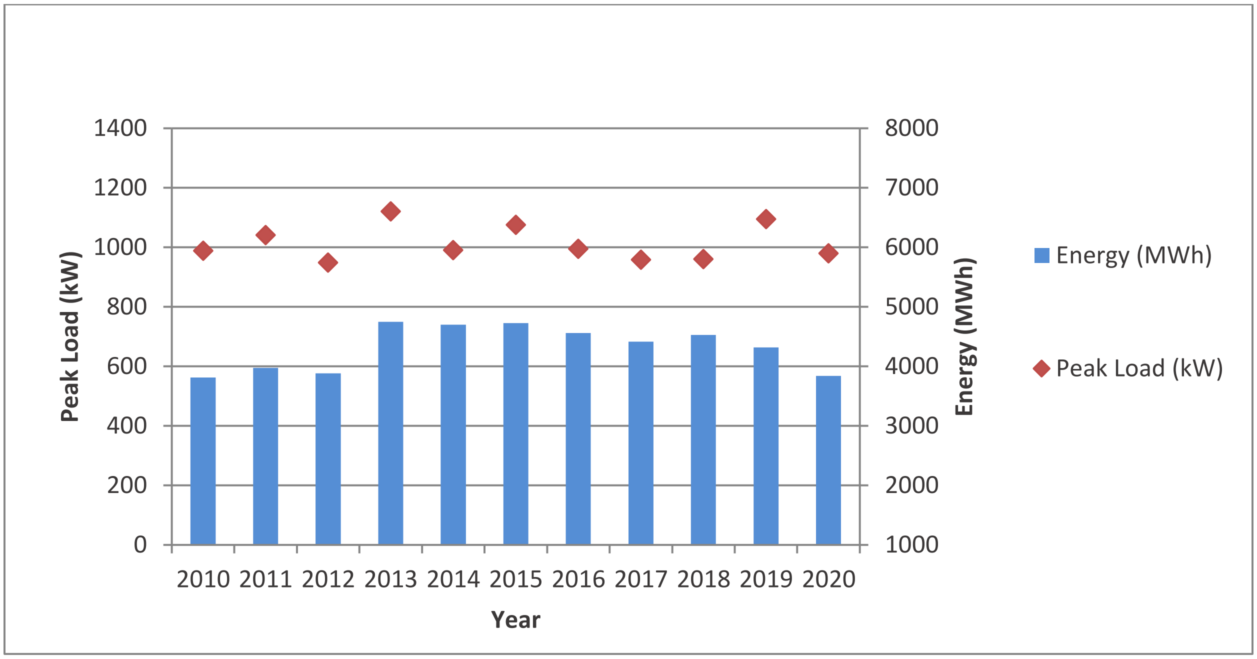

Figure 2: Mary's Harbour Historic Load

2.3 Forecasted Load Growth

Hydro prepares forecasts of the anticipated loads on all of Hydro's distribution and isolated generation systems on an annual basis. These forecasts project the peak demands for each system and are used to determine the required capacity that a distribution system or piece of equipment within the system must have in order to meet that demand. These yearly forecasts include the existing load on the system plus any expected load growth on the system. Table 1 shows the original spring 2020 Mary's Harbour forecast and Table 2 shows the revised spring 2020 forecast which shows the impact of the new service request.

[4] Values in Figure 2 are the system's gross peak loads recorded at the diesel plant and include the power used by the plant's station service load in addition to the community load.

Table 1: Spring 2020 Base Case Mary's Harbour Forecast

Mary's Harbour Forecast – Base Case

	2021	2022	2023	2024	2025
Gross MWh	4,618	4,629	4,641	4,653	4,665
Net Peak[5] kW (Summer)	1,013	1,016	1,018	1,021	1,024
Net Peak kW (Winter)	869	871	873	875	878

Table 2: Revised Spring 2020 Mary's Harbour Forecast with New Request

Mary's Harbour Forecast with Cod Plant Included[6]
Underlying Forecast is Spring 2020 - Base Case

	2021	2022	2023	2024	2025
Gross MWh	5,213	5,464	5,476	5,488	5,500
Net Peak kW (Summer)	1,139	1,149	1,152	1,154	1,157
Net Peak kW (Winter)	994	1,006	1,008	1,010	1,013

3.0 Justification

Rural Planning has completed a study of the Mary's Harbour distribution system to analyze the impact of unexpected load growth on the distribution system. The study has indicated that the main service conductor will be overloaded in the summer of 2021 and any further load growth could cause the main service conductor to fail during peak load conditions.

3.1 Service Conductor Ratings

Hydro has established criteria related to reliability requirements, at the generation level, to determine the timing of generation source additions or equipment upgrades. These criteria set the minimum level of reserve capacity and equipment ratings in the system that are required to ensure an adequate supply to meet the load; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk.

In 2021, Hydro undertook an initiative to update its standard approach to rating diesel plant service conductors. Prior to 2021, Hydro utilized CSA Standard[7] C22.1. In 2021, Hydro updated its method to reflect the 2018 edition of the Canadian Electrical Code. This resulted in the capacity ratings service conductors in certain isolated diesel plants increasing, and others decreasing.

[5] Net Peak only includes customer loads and does not include station service loads.
[6] Hydro requested a detailed monthly consumption from the customer and based on this a forecast was developed.
[7] CSA Standard C22.1 – The Canadian Electrical Code 2009 Edition.

The service conductors at the Mary's Harbour Diesel Generating Station consists of four runs of 313 MCM Diesel Locomotive ("DLO") copper cable with a combined capacity of 930 A per phase. Based on an operating voltage of 600 V and a power factor of 90%, this corresponds to a rated capacity of 930 kW.[8] Because of the unexpected load growth due to the new fish plant, the system's net peak summer 2021 load is expected to be 1,139 kW; therefore, the capacity of the service conductor must be increased.

4.0 Analysis

4.1 Identification of Alternatives

Whenever generation planning criteria violations are forecasted to occur in a diesel generating station, Hydro investigates various technical options to prevent the violations from occurring.

A targeted Conservation and Demand Management ("CDM") strategy is not a viable alternative due to the magnitude of load reduction required to offset the incremental load introduced by the new customer connection.

Hydro assessed the following alternatives to address the need for additional service conductor capacity:

- Alternative 1: Deferral;
- Alternative 2: Replace the existing 313 MCM service conductor cable with 777 MCM cable; and
- Alternative 3: Install a temporary mobile generator and advance the interconnection of Mary's Harbour to the proposed Labrador south interconnected system[9] from 2030 to 2024.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Hydro received a finalized request for service for a new fish plant in Mary's Harbour, increasing the load for the summer of 2021. This incremental load has resulted in forecast peak loads in access of the rated capacity of the service conductor at the Mary's Harbour Diesel Generating Station. While Hydro has assessed the impact and severity of exceeding the rated capacity of the conductor until replacement in

[8] Based on Hydro's old methodology for rating service conductors, the Mary's Harbour service conductor was rated at 1,227 kW.

[9] Hydro filed a supplemental proposal for phase 1 of the interconnection of Labrador South, "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021. The interconnection of Mary's Harbour is included in phase 2 of interconnection, currently planned for 2030.

2023, deferral of this project increases the potential for failure of the service conductor, and therefore, the potential for supply disruption in the long term.

4.2.2 Alternative 2: Replace Existing 313 MCM Cable with Larger Cable

This alternative involves replacing the existing service conductor which is currently comprised of four parallel runs of 313 MCM cable per phase with a 777 MCM cable. The replaced conductor will begin at the diesel plant main bus and connect to the substation transformer located next to the diesel generating station. Figure A-1 in Appendix A shows the single-line diagram of the conductor to be replaced. The capital cost to replace the existing 313 DLO cable with a larger cable is estimated to be $359,100.

4.2.3 Alternative 3: Install a Temporary Mobile Generator and Advance the Interconnection of Mary's Harbour to the Proposed Labrador South Interconnected System

This alternative involves installing an additional mobile generator at the Mary's Harbour Diesel Generating Station and advancing the proposed interconnection of the Mary's Harbour system to the proposed southern Labrador interconnected system. This mobile generator will need to be installed in the same manner as the existing mobile unit, bypassing the service conductor so that in the event that the existing mobile is unavailable, the full community load is not supplied by the service conductor. This mobile unit will need to be installed until the Mary's Harbour system can be interconnected to the southern Labrador system. This alternative, however, was ruled out due to magnitude of costs associated with advancement of the planned interconnection of the Mary's Harbour system.[10]

4.3 Proposed Alternative

Hydro is proposing to replace existing 313 MCM cables with 777 MCM cables. The increase in load associated with the new large service request requires a larger capacity cable and the recommended cables are the next available size that meets the load requirements for the foreseeable future. Alternatives such as deferral, temporarily installing mobile generation and advancing the planned interconnection of Mary's Harbour, or implementing a targeted CDM program are not valid for economic or technical reasons.

[10] The estimated cost of interconnection of the Mary's Harbour system is $14.4 million.

5.0 Project Description

The project being proposed involves upgrades in the Mary's Harbour Diesel Generating Station to address the load growth occurring in the community due to a new fish plant. The work being proposed is the replacement of the existing service conductor from 313 MCM to 777 MCM. The project will require the existing service conductor conduit to be replaced with larger conduit to accommodate the increased conductor size. All work will be completed during a single outage, and will not require additional generation. Table 3 shows the estimated cost for the entire project while Table 4 shows the schedule for the project.

The estimate for this project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	87.2	0.0	0.0	**87.2**
Labour	149.6	25.3	0.0	**174.9**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	28.5	6.0	0.0	**34.5**
Interest and Escalation	16.0	16.8	0.0	**32.8**
Contingency	26.5	3.2	0.0	**29.7**
Total	**307.8**	**51.3**	**0.0**	**359.1**

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning:		
Open job and develop scope statement and baseline schedule	February 2022	March 2022
Design:		
Detailed design	March 2022	May 2022
Procurement:		
Procure materials and construction tender	May 2022	August 2022
Construction:		
Installation of new service conductor	August 2022	December 2022
Commissioning:		
Acceptance inspection	July 2023	August 2023
Close Out:		
Project close out	September 2023	September 2023

6.0 Conclusion

System analysis indicates that the current diesel generating station main service conductor in Mary's Harbour is unable to support the Mary's Harbour system load in the long term due to a change in the ratings of the service conductor and unexpected load growth from a fish plant in the summer of 2021. Both of these factors are contributing to conditions that are causing the service conductor to violate Hydro's Rural Isolated Diesel Generation Planning Criteria (see Attachment 1). If the equipment is not upgraded, the increase in load on in the summer will cause the diesel generating station to operate outside of planning criteria.

An in-depth analysis of the Mary's Harbour system has determined that the least-cost, long-term solution to accommodate the forecasted load growth is for Hydro to replace the existing 313 MCM service conductor cables with 777 MCM cables. The total capital cost for the project to address the load growth in Mary's Harbour is $359,100 with the project scheduled to be completed in two years.

Appendix A

Single Line Diagram of Mary's Harbour Diesel Generating Station

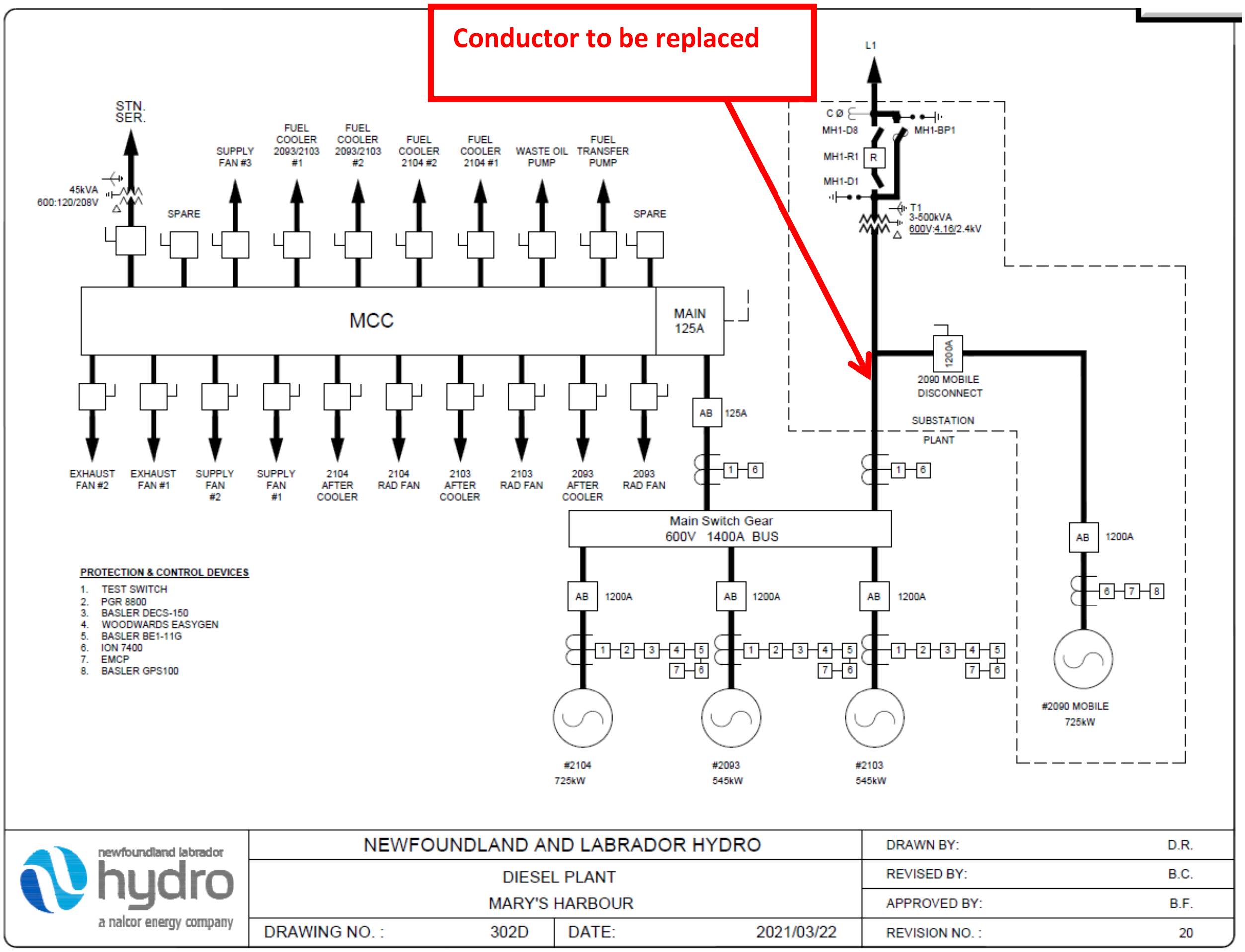

Figure A-1: Single-Line Diagram of Mary's Harbour Diesel Generating Station

Attachment 1

Rural Planning Standard RP-S-002:

Rural Isolated Systems Generation Planning Criteria

RURAL PLANNING STANDARD

Rural Isolated Systems Generation Planning Criteria

Doc # RP-S-002

Date: 2020/08/21

Table of Contents

1 PURPOSE

The purpose of this document is to present Rural Isolated Generation Planning Criteria to be applied to the Diesel Generation Plants within the Province of Newfoundland and Labrador.

2 TERMS, ABBREVIATIONS, AND ACRONYMS

Firm Capacity means the amount of capacity that can be reasonably guaranteed from a generating unit at a particular instant when required. In the case of capacity planning, it describes the capacity that can be expected from a diesel generating plant during the system peak load.

Standby Power:[1] Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year.

Prime Power:[1] Output available with varying load for an unlimited time that is typically 90% of Standyby Power Rating. Average power output is 70% of the prime power rating. Typical peak demand is 100% of prime rated ekW with 10% overload capability for emergency use for a maximum of 1 hour in 12. Overload operation cannot exceed 25 hours per year.

Continuous Power:[1] Output available with non-varying load for an unlimited time that is typically 70% of Standyby Power Rating. Average power output is 70–100% of the continuous power rating. Typical peak demand is 100% of continuous rated ekW for 100% of operating hours.

[1] Based on the IOS8528 Standard.

3 INTRODUCTION

A Rural Isolated System is an electric power system that is isolated from either the Island or Labrador Grid, and is typically supplied by diesel based generation. Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities for Rural Isolated Systems the following have been adopted.

4 RURAL PLANNING CRITERIA

4.1 Capacity

Capacity for Rural Isolated Systems is provided by Diesel Generating Plants which house a number of Diesel Generator Sets ("gensets"). The minimum number of units in a diesel plant is three, and typical plant size is from three to four units, although some (typically larger) plants contain more units. The prime power rating of the gensets is used to calculate the firm capacity in the rural isolated diesel plants. Gensets are assumed to be capable of achieving their respective nameplate ratings throughout their lifecycle.

In some cases power is also supplied to the system by alternative energy sources such as wind, solar, and small hydro. To date, wind and solar are considered as non-firm energy sources even when coupled with an energy storage system. That is, the wind and/or solar generation is not considered to provide firm capacity to the system during peak load. This is due to the random nature of the energy supply (wind/solar) which will not necessarily be present when it is needed. In the case of hydro-electric plants, run-of-river plants, are treated the same as wind or solar, and provide no firm capacity to the system during peak load. A hydro-electric plant with a storage reservoir will provide some degree of firm capacity to the system. The amount of capacity is dependant on the particular site and the design of the plant.

Hydro applies firm capacity criteria, which considers all the firm power sources available to the system, when determining the amount of capacity needed to supply the system's peak load according to the five year load forecast. The criterion used to guide Hydro's planning activities in relation to system capacity is described below.

4.1.1 Firm Capacity Planning Criteria

Hydro's generation reliability criterion for the Isolated Rural Systems is stated as follows: Hydro shall maintain firm generation capacity to meet the system peak load. Firm generation capacity is defined as the total installed capacity on the system not including non-firm energy sources as noted above minus the largest single unit. Exemptions or modifications to this criterion may be considered in the following situations:

- Additional generation may be prudent in situations where the introduction of a subtransmission system supplying multiple communities decreases existing system reliability.
- Less generation may be prudent in situations where non-firm generation has a historical record of operating at a low unavailability rate.
- Additional generation may be prudent in situations where major diesel plant modifications, such as the construction of a new diesel plant or major extension, are planned and the cost to add additional generation is of minor incremental cost.

Rationale:

The Firm Capacity Planning Criteria covers a first contingency situation. It is considered to provide a reasonable level of reliability to customers in the Rural Isolated Systems, and gives a good compromise between cost of service and reliability. Hydro has a long standing practice of using this criterion with good success. A survey conducted by Hydro in 2007 has confirmed that this criterion is similarly practiced in other utilities. This criterion can be reasonably considered to be an industry standard practice.

4.2 Energy

Energy for Rural Isolated Systems is provided from either Type A (Arctic Grade), or Type B Diesel Fuel supplied by a local fuel vendor or stored on site by Hydro. Where cost-effective, Hydro will contract with a local fuel vendor for supply of diesel fuel to the diesel plants. In cases where this arrangement is not feasible, or not possible, Hydro will maintain long-term bulk fuel storage at the site. The amount of fuel to store is planned such that the diesel plant can supply energy requirements of the system over the winter period when fuel deliveries to the site are unavailable.

4.2.1 Vender Delivered Fuel:

In the case where Hydro relies on a contract with a fuel vendor, the following criteria are used to guide Hydro's planning criteria.

- Sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for two weeks at all times of the year.
- The total available fuel storage capacity required on site shall meet the energy requirements of the system for a minimum of three weeks at all times of the year.

Assumptions:

- The local fuel vendor has enough storage to meet Hydro's winter fuel requirements.
- The local fuel vender is scheduled to fill up Hydro's storage at least once every seven days.
- If more than twenty-one days of storage is available, then deliveries may occur less often.
- If a location has a much higher, or lower risk of delay in fuel storage than then typical, additional, or less fuel storage may be required.

Rationale:

For planning purposes a fuel delivery of once every seven days is assumed because fuel carrying ferries operate on a weekly schedule. The Fuel Storage Planning Criteria covers the contingency situation of a one week delay in fuel delivery. If the vendor fills Hydro's storage every seven days and Hydro's fuel storage is large enough for at least twenty-one days of fuel then there should always be at least two weeks of fuel in storage. If the vendor cannot supply fuel on the seventh day due to an emergency (pipe failure, pump failure, or ferry delay, etc.) there is two weeks fuel available for backup.

Exception:

If the fuel vendor contracted by Hydro resides in the same community as the diesel plant the minimum required fuel storage capacity on site is reduced to reflect the decreased risk in fuel delivery as they are not affected by highway access or ferry schedules.

- Sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for seven days at all times of the year.

- The total available fuel storage capacity required on site shall meet the energy requirements of the system for a minimum of ten days at all times of the year.

4.2.2 Bulk Fuel Storage

In the case where Hydro must maintain long-term bulk fuel storage, the following criteria are used to guide Hydro's planning activities.

- Island Isolated Systems; sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for four consecutive months.
- Labrador Isolated Systems; sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for nine consecutive months.

Assumptions:

- Final Fuel delivery via shuttle tanker is in late November.
- Hydro's fuel requirements are communicated to the vendor in the fall before the final fuel delivery.

Rationale:

The Fuel Storage Planning Criteria covers a first contingency situation. It is considered to provide a reasonable level of reliability to customers in physically isolated communities, and gives a good compromise between cost of service and reliability. Hydro has a long standing practice of using this criterion with good success. A survey conducted by Hydro in 2007 revealed that most other utilities surveyed only maintain short-term fuel storage and rely on deliveries from fuel vendors. Only one utility surveyed maintained long-term bulk fuel storage. It appears that fuel storage practices are region specific and dependant on the local resources available (i.e. road access, local fuel vendor, etc.).

4.3 Diesel Plant Equipment

In addition to generating capacity, and energy, Hydro plans the capacity of the major diesel plant equipment that is responsible for getting the power from the individual diesel units to the power distribution system. The components covered under this criterion are the Main Breaker, Main Bus, and Service Conductors and is defined as follows:

Diesel Plant Equipment Capacity Planning Criteria

No equipment shall be loaded above 100% of its rated capacity at rated ambient temperature.

Assumptions:

- The ratings are continuous ratings.
- Ambient temperature is thirty degrees Celsius.

4.4 Diesel Plant Substations

Capacity planning of diesel plant substations (step-up transformers) is covered under Hydro's Distribution Planning Criteria. The criteria are re-iterated here since the substation forms the critical interface between the diesel plant and the distribution system.

Substation Capacity Planning Criteria

Transformers at Substations shall not be loaded above 110% of the nameplate rating.

In the case of diesel plant substations; a spare shall be retained on site such that in the event of the loss of a single unit; the spare can be installed to restore power within a reasonable time frame. The standard substation is an aerial bank of three single-phase transformers connected in a three-phase bank. The maximum size aerial bank is 1500 kVA (3x500 kVA). This transformer size was selected since it is considered to be the largest size transformer that can be handled without assistance from a bucket truck, or crane.

If transformer capacity exceeding the maximum size aerial bank is required a three-phase padmount transformers may be used. Due to the size of these units and the remote nature of these plants, the equipment and personnel required to replace a three-phase transformer may not be available when needed. To prevent a prolonged system outage, in the event of a three-phase transformer failure, a second padmount transformer may be installed and available as a spare to use when required.

Document Summary

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Document Distribution:	Rural Planning

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Revision	Prepared by	Reason for change	Effective Date
1	Tyler Stevens	Updated and included in DMS	2020/08/21

Document Approvers

Position	Signature	Approval Date
Team lead, Rural Planning	Scott Henderson	Sept 17, 2020

Document Control

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Tab 1: Hydraulic Generation Refurbishment and Modernization

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DAVE ROYLE
SIGNATURE
7/15/21
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Hydraulic Generation Refurbishment and Modernization (2022–2023)

July 2021

newfoundland labrador hydro

A report to the Board of Commissioners of Public Utilities

Hydraulic Generation Refurbishment and Modernization – (2022–2023)

Category: Generation – Hydraulic Plant

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") aims to replace or refurbish failing or failed hydraulic generation assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Starting in 2017 and continuing in the 2022 Capital Budget Application ("CBA"), Hydro has consolidated much of its hydraulic generation capital work into one Hydraulic Generation Refurbishment and Modernization project. Hydro's philosophies for the assessment of equipment and the selection of capital work for the Hydraulic Generation Refurbishment and Modernization Project are outlined in the Hydraulic Generation Asset Management Overview ("Asset Management Overview").[1] In the 2022 CBA, Hydro proposes the following program-based activities under the Hydraulic Generation Refurbishment and Modernization project.

Hydraulic Generating Units Program

- Turbine and generator six-year overhauls;
- Replace generator bearing cover seals;
- Replace control cables; and
- Replace surface air coolers.

[1] There have been no revisions to this document since Hydro's 2020 CBA. Hydro is including the version that was provided in its 2020 CBA in its 2022 CBA for ease of reference.

Hydraulic Structures Program

- Control structure refurbishments.

Reservoirs Program

- Upgrade public safety around dams.

Site Buildings and Services Program

- Draft tube deck substructure condition assessment.

Common Auxiliary Equipment Program

- Replace cooling water strainer; and
- Communication link upgrade.

Six activities are scheduled for a one-year execution period and five activities are scheduled for multi-year execution periods. The total project estimate for all activities in the Hydraulic Generation Refurbishment and Modernization project (2022–2023) is $6,759,500.[2]

[2] $2,970,600 in 2022 and $3,788,900 in 2023.

Contents

List of Attachments

1.0 Introduction

1.1 Hydraulic Generation Refurbishment and Modernization Program

Hydro has ten hydraulic generating stations which require more than 3,000 individual assets to function. To support Hydro's asset management strategy, the assets are categorized based on the asset hierarchy. This grouping of the assets then makes up the individual programs within this proposal. The assets have been grouped into five programs as described in Section 2.0.

2.0 2022–2023 Projects

The assets designated for replacement, refurbishment, or modernization in the 2022–2023 Hydraulic Generation Refurbishment and Modernization project have been selected in accordance with the philosophies for assessment and selection found in Hydro's Asset Management Overview.[3]

Hydro's hydraulic generation infrastructure has been divided into five categories:

1) Hydraulic generating units,
2) Hydraulic structures,
3) Reservoirs,
4) Common auxiliary equipment, and
5) Site buildings and services.

2.1 Hydraulic Generating Units Program

The following equipment upgrades and/or refurbishment for hydraulic generating units are proposed for 2022–2023:

- Turbine and generator six-year overhauls for Units 4 and 6 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir");
- Replace generator bearing cover seals;

[3] The Hydraulic Generation Asset Management Overview outlines the Company's hydraulic generation asset maintenance philosophies. There are no changes to the document for 2022 and, as such, Version 3, which was filed with the 2020 CBA, is included as Attachment 1 for reference purposes.

- Replace control cables; and
- Replace surface air coolers.

2.1.1 Turbine and Generator Six-Year Overhauls

Description of Equipment

The turbine and generator are the two primary components of a hydraulic generating unit. Water is used to rotate the turbine, which is connected to the generator to convert the mechanical energy into electricity. Further information on the equipment is contained in the Asset Management Overview.

The Bay d'Espoir Units 4 and 6 are both Francis turbine generating units ("Francis Turbine Runner") and are rated for 76 MW each. Bay d'Espoir Unit 4 was placed in service in September 1968 and Unit 6 was placed in service in March 1970. The Francis Turbine Runner, which is shown in Figure 1, extracts energy from the pressure differential of the water that flows through the turbine. The runner in the Francis configuration is always submersed in water. The flow enters the runner in the radial direction flowing towards its axis and, after interaction with the runner blades, exits along the direction of the axis as illustrated in Figure 2.

Figure 1: Francis Turbine Runner from Bay d'Espoir Unit 7

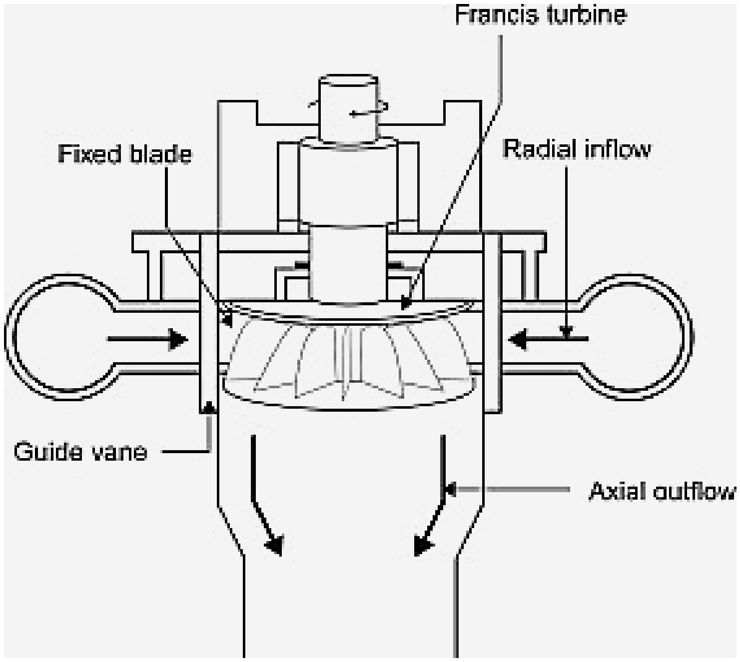

Figure 2: Mixed Flow Francis Turbine

A preventive maintenance six-year overhaul (“PM9”) is performed on the units with more detailed inspections than those in annual inspections (“PM6”). The PM9 inspections incorporate the PM6 activities, along with additional recommended activities from the original equipment manufacturer (“OEM”) to support the long-term reliability of the unit. Inspection of all major components (testing and/or repairs as required) on a six-year frequency contributes to a reduction in forced outages and deratings, as well as unplanned maintenance outages. For further information on preventive maintenance timing, refer to the Asset Management Overview.

Current Status

Bay d’Espoir Units 4 and 6 are planned to undergo PM9 overhauls in 2022. Both units are currently in operational condition and available for service except during maintenance or forced outages.

A list of major work and upgrades at Bay d’Espoir Unit 4 is provided in Table 1.

Table 1: Major Work and Upgrades for Bay d'Espoir Unit 4

Year	Major Work/Upgrade
2015	Excitation Transformer Replaced
2015	Auto-Grease System Replaced
2014	Thrust/Guide Bearing Coolers Replaced
2012	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2012	Upgraded Unit Protection
2012	Generator Rotor Poles Refurbished
2012	Stator Rewind
2009	Cooling Water Replaced
2001	Spherical Valve Controls Upgrade Unit 4
1998	Exciter Replacement
1994	Runner Replacement

A list of major work and upgrades at Bay d'Espoir Unit 6 is listed in Table 2.

Table 2: Major Work and Upgrades for Bay d'Espoir Unit 6

Year	Major Work/Upgrade
2015	Spare Excitation Transformer Replaced
2014	Auto-Grease System Replaced
2014	Excitation Transformer Replaced
2014	Refurbished Turbine Bearing
2010	Replaced Cooling Water Piping
2000	Generator Bearing Cooling Coil Installation
1999	Replace Cooling Water Pump #6
1998	Turbine Bearing Cooling Coil Installation
1995	Exciter Replacement
1995	Runner Replacement

Justification

This work is required to maintain reliable operation of Bay d'Espoir Units 4 and 6 turbine and generator.

Alternatives

Deferral of this project is not a viable option as it will increase the risk of premature unit failures. There are no alternatives to the PM9 overhauls. This is time based work performed every six years to maintain reliability of the operating units.

Project Description

This project involves the partial dismantling of both turbine/generator units to inspect, test, clean, refurbish, and replace defective components. In addition to testing activities, PM9 overhauls involve cleaning and inspecting the rotor and stator assembly, electrical testing on rotor/stator assembly, calibration and testing of turbine and generator protection devices, verification of bearing and seal clearances, and a thorough inspection of the turbine, draft tube, and penstock.

The project is scheduled to be completed in 2022 with estimated costs of $225,000 for Bay d'Espoir Unit 4 and $225,400 for Unit 6. Table 3 and Table 4 contain the project estimates for the overhauls of Bay d'Espoir Units 4 and 6, respectively.

Project Estimates

Table 3 and Table 4 provide the project estimates for Bay d'Espoir Units 4 and 6 overhauls.

Table 3: Bay d'Espoir Unit 4 Overhaul Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	16.0	0.0	0.0	**16.0**
Labour	170.6	0.0	0.0	**170.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	7.6	0.0	0.0	**7.6**
Interest and Escalation	13.9	0.0	0.0	**13.9**
Contingency	16.9	0.0	0.0	**16.9**
Total	**225.0**	**0.0**	**0.0**	**225.0**

Table 4: Bay d'Espoir Unit 6 Overhaul Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	16.0	0.0	0.0	**16.0**
Labour	170.6	0.0	0.0	**170.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	7.6	0.0	0.0	**7.6**
Interest and Escalation	14.3	0.0	0.0	**14.3**
Contingency	16.9	0.0	0.0	**16.9**
Total	**225.4**	**0.0**	**0.0**	**225.4**

1 ## Project Schedule

2 Table 5 and Table 6 provide the anticipated project schedules for Bay d'Espoir Units 4 and 6 overhauls.

Table 5: Bay d'Espoir Unit 4 Overhaul Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	February 2022	March 2022
Construction:		
Perform PM9 on Bay d'Espoir Unit 4	July 2022	July 2022
Commissioning:		
Run up the unit to confirm operation and release to operations	July 2022	July 2022
Close Out:		
Close work order, complete all documentation, and complete lessons learned	August 2022	August 2022

Table 6: Bay d'Espoir Unit 6 Overhaul Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	February 2022	March 2022
Construction:		
Perform PM9 on Bay d'Espoir Unit 6	June 2022	September 2022
Commissioning:		
Run up the unit to confirm operation and release to operations	September 2022	September 2022
Close Out:		
Close work order, complete all documentation, and complete lessons learned	November 2022	November 2022

3 ### 2.1.2 Replace Generator Bearing Cover Seals

4 ## Description of Equipment

5 The generator bearing felt seal is designed to prevent vaporized oil emissions from escaping the bearing
6 oil sump. The seal is comprised of a two layered felt seal located inside the generator top bearing
7 covers. Figure 3 illustrates the arrangement of the generator oil sump set up on Units 1–6 in
8 Bay d'Espoir.

The generator bearing covers are stationary to the generator shaft which rotates during unit operation. The generator bearing assembly resides approximately 3” below the felt seal arrangement.

The generator guide bearing requires an oil bath during operation for lubrication and temperature control. For the bearing to function properly, the generator shaft must rotate at a sufficient speed to draw in oil, pressurize it to form a hydrodynamic layer, and expel it with any debris formed during the process. When a generator thrust/guide bearing assembly reaches normal operating temperature the bearing discharge oil creates an oil mist inside the bearing oil sump just below the generator top covers. Some of this oil mist is expelled through the gap between the felt seal and generator shaft. The cooling air that flows throughout the generator housing and ventilation slots in the rotor and stator contains other contaminants such as carbon dust, brake dust, and insects. These contaminants mix with this oil mist producing a partially conductive coating that is distributed throughout the unit by the cooling air. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

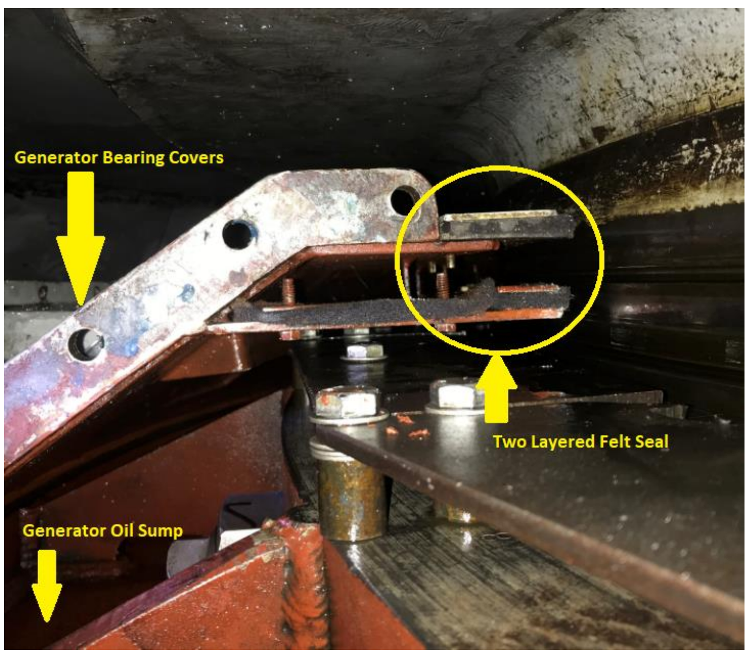

Figure 3: Generator Bearing Oil Sump Arrangement

Current Status

Oil mist created from the operation of the bearing escapes through the clearance between the seal and shaft on Bay d'Espoir Units 1–6, resulting in contamination of the unit's main bracket, brake assembly, rotor, and stator. Various attempts have been made in the past to reduce oil emissions since it has been an ongoing issue since the units were first commissioned and these attempts are listed in Table 7.

Table 7: Attempts to Resolve Oil Misting Issue

Year	Execution Efforts	Outcome
2020	Installation of a brush seal on top of the generator bearing covers in replacement of the felt seal in that area (Figure 4).	Installed in October 2020. After two months of operation, an inspection revealed positive results with a noticeable reduction in oil misting on all external components and negligible effect on unit operation.
2014	Unit 2: Installation of a newly designed/modified generator guide bearing, installation of baffles, and altering the way oil was discharged from the bearing. Some internal ports that were used to supply the bearing with oil were plugged to reduce flow.	The change in oil flow resulted in a ten degree increase in bearing temperature bringing the temperature within unacceptable operating regime. This change in oil flow caused a temperature increase that was unexpected by the OEM and the plan to continue on with other units was cancelled. The bearings are required to be as cool as possible to allow for reliable operation.
1970	Installation of air baffles and oil mist catchment containers. This was a major modification of the generator covers.	Emission problem unresolved.
Various	Adjustments of the felt seal to bring the seal closer to the generator shaft.	Resulted in making contact with the shaft and causing vibration issues. The felt seal prevented the generator shaft from revolving in its preferred axis and generated heat on the journal and caused vibration.

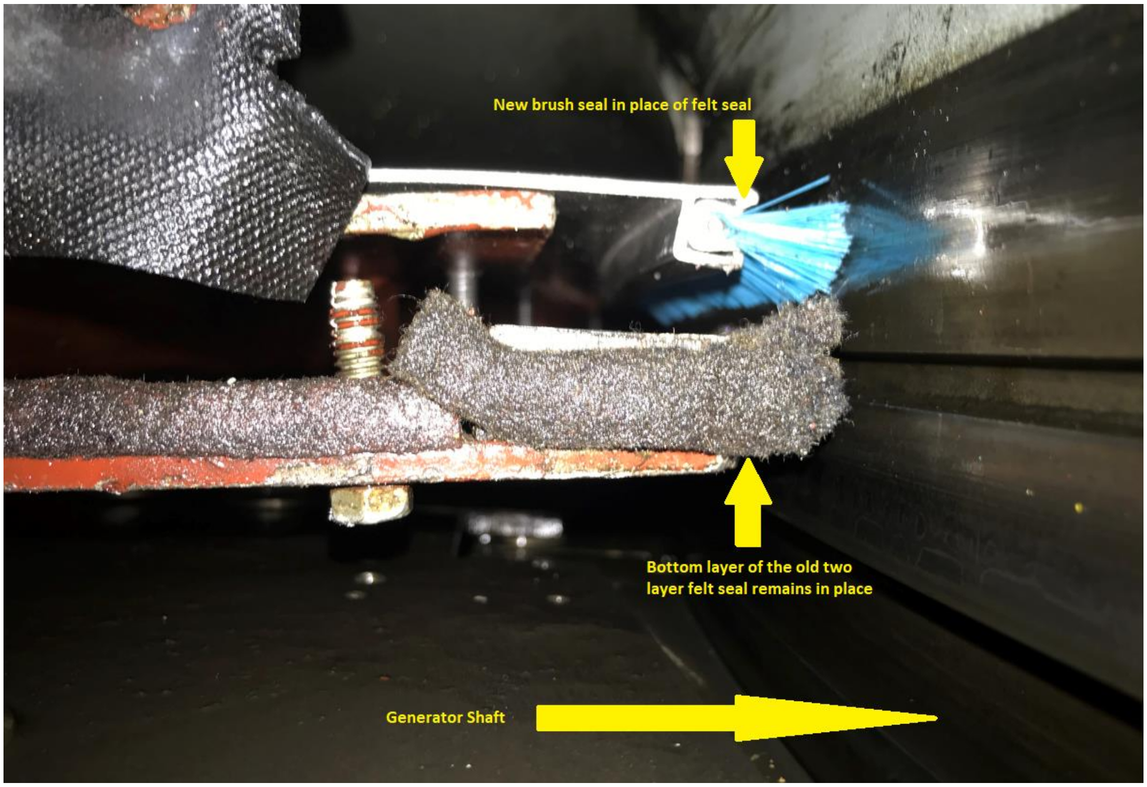

Figure 4: New Brush Seal Arrangement

Justification

This project is necessary to eliminate oil emissions and leaks from the generators on Units 1–3, 5, and 6 at Bay d'Espoir to ensure reliable operation of the generators. Emission control upgrades for Unit 4 were carried out under capital work in 2020 as described in Table 7.

Alternatives

As seen in Table 7, the project in 2020 has seen success in controlling oil emissions, with no other viable alternatives.

Project Description

This project scope involves the modifications of Units 1–3, 5, and 6 generator bearing cover seal arrangement. The work will mimic the execution efforts carried out to install a new brush seal on Unit 4 in 2020.

The new brush seal is designed to lie on the generator shaft without disturbing the rotating axis and clearance is not required between shaft and seal. Engineering design has been complete for Unit 4 and thus will not be required for the remaining units since they are all of the same vintage and design. This is a two year project to allow time for installation on two units in one year and three units the second year. The timing of the installations is dependent on alignment with outages and other work that is being completed on the units in the same year.

The scope of this project consists of:

- Design check to ensure no modifications to original design from unit to unit;
- Fabrication of the new seals;
- Removal of existing seal and generator covers;
- Modification of the covers to accommodate the new seals; and
- Installation of the new seals.

Project Estimates

Table 8 provides the project estimate for Replace Generator Bearing Cover Seals.

Table 8: Replace Generator Bearing Cover Seals Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	54.0	6.0	0.0	**60.0**
Labour	113.9	134.4	0.0	**248.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	5.6	8.5	0.0	**14.1**
Interest and Escalation	12.4	21.4	0.0	**33.8**
Contingency	17.3	14.9	0.0	**32.2**
Total	**203.2**	**185.2**	**0.0**	**388.4**

Project Schedule

Table 9 provides the anticipated project schedule for Replace Generator Bearing Cover Seals.

Table 9: Replacement Generator Bearing Cover Seals Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	January 2022	March 2022
Procurement:		
Procure new seals based on design installed on Unit 4 in 2020	March 2022	July 2022
Install/Commission 2022:		
Install new seal design on two units during annual maintenance. Unit to be selected in 2022	August 2022	October 2022
Install/Commission 2023:		
Install new seal design on three units during annual maintenance. Unit to be selected in 2023	June 2023	October 2023
Close Out:		
Close work order, complete all documentation, and complete lessons learned	October 2023	November 2023

2.1.3 Replace Control Cables

Description of Equipment

Control cables are used for carrying signals for generator protection and control purposes. Many of the control cables installed in Bay d'Espoir are of an older vintage that have insulation manufactured with an oil-based compound. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Current Status

The control cables on Unit 6 in Bay d'Espoir have been in service since 1970 and are approaching the end of their useful life. Oily residue has been found to leak from the cables into the junction boxes and onto cable connections. This is an indication of the breakdown of the insulation. Also, mitigation work on leaking cables has revealed that associated junction boxes will need to be replaced.

As leaking continues, the cables will dry out and the insulation will fail. Such a failure may result in control equipment malfunction resulting in a forced outage of the generator.

Justification

Replacement of control cables listed in this project is required to maintain reliable operation of the generating units.

Alternatives

There are no alternatives to replacing deteriorated cables.

Project Description

The scope of this project includes:

- Replacement of the 600 V control cables on Unit 6; and
- Replacement of associated oil contaminated junction boxes and terminal blocks on Unit 6.

The project will be executed in 2022 with estimated costs of $304,800. Refer to Table 10 for the budget breakdown of the Replace Control Cables project.

Project Estimates

Table 10 provides the project estimate for the Replace Control Cables project.

Table 10: Replace Control Cables Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	105.7	0.0	0.0	**105.7**
Labour	152.2	0.0	0.0	**152.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	1.6	0.0	0.0	**1.6**
Interest and Escalation	19.3	0.0	0.0	**19.3**
Contingency	26.0	0.0	0.0	**26.0**
Total	**304.8**	**0.0**	**0.0**	**304.8**

Project Schedule

Table 11 provides the anticipated project schedule for the Replace Control Cables project.

Table 11: Replace Control Cables Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	January 2022	February 2022
Procurement:		
Develop finalized list of cables requires and place order for the cables	February 2022	March 2022
Install/Commission 2022:		
Install new cables and junction boxes	June 2022	July 2022
Close Out:		
Close work order, complete all documentation, and complete lessons learned	November 2022	November 2022

2.1.4 Replace Surface Air Coolers

Description of Equipment

The Cat Arm Hydroelectric Generating Station ("Cat Arm") is comprised of two hydroelectric units, rated for 67 MW each, that are operated continuously to meet island system load requirements. Both hydroelectric units use four surface air coolers to cool the ambient temperatures in the generator housing to ensure winding and core temperatures of the stator and rotor are within acceptable operating ranges when online. The surface air coolers are comprised of a tube and fin design with epoxy coated carbon steel tubes with aluminum fins as seen in Figure 5.

Cooling water is supplied to the surface air cooler tubes via a connection to the penstock. The water passes through the inside of the tubes of the cooler and heat transfer between the water inside the tubes and air outside of the tubes promotes heat transfer from the air to the water to reduce generator ambient air temperatures. Figure 6 illustrates the flow of media through a tube and fin type cooler. In the case of the surface air coolers, the liquid is the cooling water and the air is the generator ambient air.

As a method of protection, the surface air coolers are equipped with thermostats that have alarm and trip settings to ensure the generators do not run at higher temperatures and risk extensive damage to critical components such as the stator and rotor windings.

Figure 5: Single Surface Air Cooler used at Cat Arm

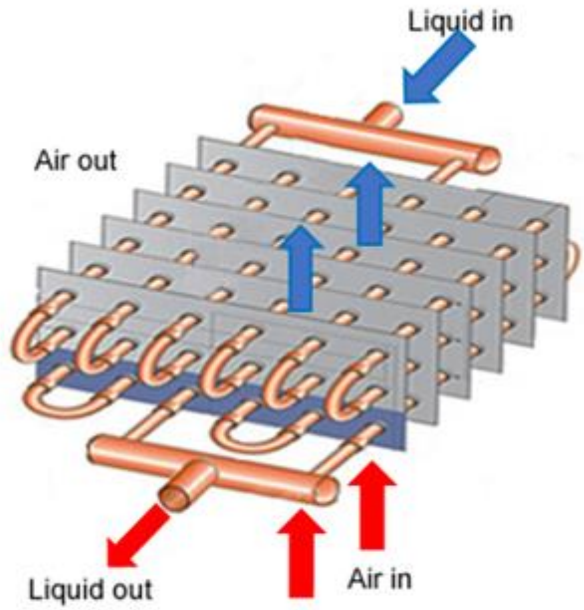

Figure 6: Typical Tube and Fin Cooler Media Flow

Current Status

Cat Arm was first placed into service in 1985 and the surface air coolers have never been replaced. The surface air coolers at Cat Arm are susceptible to organic buildup from the supply water and thus preventative maintenance is carried out annually to clean the coolers. This task requires removal of the coolers from the unit and the use of physical labour and chemicals. This annual preventative maintenance cleaning has allowed the coolers to run without significant issues for the majority of their time in service; however, in recent years, a number of forced outages related to surface air cooler fouling have occurred within the 12-month time frame of the annual maintenance periods. While annual cleaning substantially improves cooling performance, each passing year there is a measurable amount of fouling left in the coolers which cannot be cleaned by any available means. This residual fouling has compounded and thus cooler performance is degrading at an exponential rate with each passing year.

Since 2017, there have been ten noted occurrences of cooler fouling which has led to forced unit derating. These deratings generally come in the warmer months since ambient temperatures around the generator and supply water temperatures are higher and thus the surface air coolers cooling ability is not as prominent. These occurrences are listed in Table 12.

Table 12: Deratings Associated with Surface Air Coolers

Date	Unit	Comments
17-Aug-2017	U1	Reduced load
22-Jul-2018	U2	Operator increased surface air cooler flow
2-Aug-2019	U2	Reduced load
22-Jul-2019	U1	Reduced load
21-Jul-2019	U1	Reduced load
14-Jul-2019	U1	Operator increased surface air cooler flow
2-Jul-2019	U1	Reduced load
24-Jun-2020	U1	Reduced load
1-Jul-2020	U1	Reduced load
13-Jul-2020	U1	Reduced load

Justification

This project is required to ensure reliable operation of the Cat Arm generating units. Surface air coolers performance is critical to the reliable operation of Cat Arm Units 1 and 2. With surface air cooler performance already compromised, the generator is exposed to higher ambient air temperatures and this exposure can be detrimental to the reliability of the generator.

Alternatives

There are currently no other alternatives to the replacement of the surface air coolers in Cat Arm. The current surface air coolers are experiencing premature fouling issues that are only partially mitigated by regular maintenance and require replacement. A new design during replacement will allow for reduced maintenance and optimized cooling for the generator.

Project Description

The scope of this project includes:

- Redesign of the existing surface air coolers to allow for *in-situ* cleaning, reducing downtime of cleaning activities. This will assist with decreasing maintenance costs and more efficient use of resources during maintenance activities;
- Provide engineering drawings and technical design packages for the purchase of two new sets of surface air coolers for Cat Arm Units 1 and 2. Purchase shall also include a minimum of one spare surface air cooler;
- Develop contract documentation for the procurement of the new cooler sets;

- Planning and scheduling to install the new cooler sets during PM6 activities;
- Engineering field support to assist with the installation of the new cooler sets;
- Physical disposal plans for the removed surface air coolers; and
- Develop and compile all close-out documentation including but not limited to operational procedures, maintenance tactics, engineering drawings, and asset retirements forms.

The project will be executed in 2022–2023 with estimated costs of $602,000. Refer to Table 13 for the budget breakdown of the Replace Surface Air Coolers project.

Project Estimates

Table 13 provides the project estimate for the Replace Surface Air Coolers project.

Table 13: Replace Surface Air Coolers Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	200.0	13.5	0.0	**213.5**
Labour	61.1	122.9	0.0	**184.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	70.0	0.0	0.0	**70.0**
Other Direct Costs	1.6	35.2	0.0	**36.8**
Interest and Escalation	19.2	31.2	0.0	**50.4**
Contingency	31.9	15.4	0.0	**47.3**
Total	**383.8**	**218.2**	**0.0**	**602.0**

Project Schedule

Table 14 provides the anticipated project schedule for the Replace Surface Air Coolers project.

Table 14: Replace Surface Air Coolers Project Schedule

Activity	Start Date	End Date
Planning: Open work order and plan and develop detailed schedules	January 2022	March 2022
Engineering: Site visit, measurements, design/specification development for tender/procurement/fabrication	April 2022	July 2022
Procurement: All the required materials for surface air cooler replacement for Cat Arm Units 1 and 2	July 2022	November 2022
Install/Commission: Remove old and install new surface air coolers, confirm operation, and release to operations	August 2023	August 2023
Close Out: Close work order, complete all documentation, and complete lessons learned	September 2023	November 2023

2.2 Hydraulic Structures Program

The following equipment upgrades and/or refurbishment for hydraulic structures are proposed for 2022–2023:

- Control structure refurbishments including:
    - Refurbish hydraulic structures—various locations.

2.2.1 Control Structure Refurbishments

Background

This work is a continuation of Hydro's program to refurbish hydraulic structures within Hydro's generating system.

The structures identified for the Hydraulic Generation Refurbishment and Modernization (2022–2023) proposal are Salmon River Spillway (Replace Monorail Beam and Associated Mounts) and Burnt Dam (Refurbish Gate 2).

Salmon River Spillway

Description of Equipment

The Salmon River Spillway, located 18 km from Bay d'Espoir, was placed in service in 1967 during the original construction of Bay d'Espoir. The spillway is a concrete structure equipped with three wheeled gates that are 9.75 m wide by 7.93 m high and operate under a maximum head of 9 m. The gates are operated with screw stem hoists and there is an emergency hydraulic hoist in the event of power supply or motor failure. The spillway discharges excess water from the Long Pond Reservoir to the Salmon River (Figure 7).

Figure 7: Salmon River Spillway

This structure uses a monorail hoist suspended on an I-beam, seen in Figure 8, in order to place stop logs in front of a gate when the gates require maintenance or repairs. The monorail beam has a span of approximately 155’ and features a dual trolley 5 ton hoist.

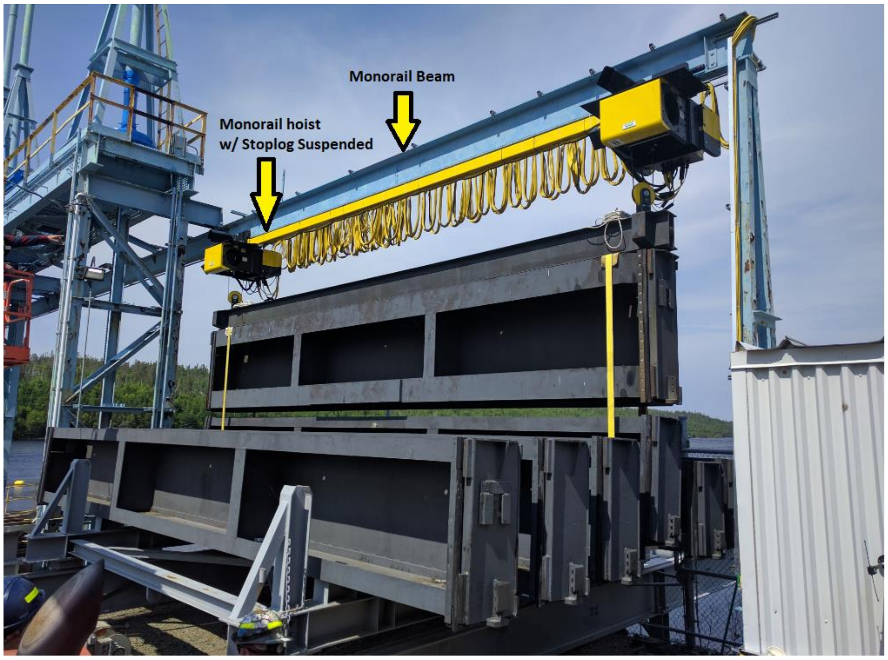

Figure 8: Monorail Beam and Stop Logs

Current Status

The Salmon River Spillway monorail hoist was replaced in 2016. During replacement of the monorail hoist, an internal engineering inspection of the monorail beam and associated structural mounts was completed. The inspection revealed deterioration of the components and repair/refurbishment work was required to reliably operate the monorail hoist in the long term. Issues included noticeable head scaling on structural mounting bolts, scaling on structure steel, uneven surfaces for monorail hoist rollers, and alignment gaps between monorail beam sections as seen in Figure 9 to Figure 13. Affected areas generally show signs of corrosion and degradation of support mounts and hardware.

Figure 9: Structure Bolt Scaling

Figure 10: Alignment Gaps in Monorail Beam

Figure 11: Scaling on Structural Steel

Figure 12: Monorail Beam Scaling

Figure 13: Corrosion along the Monorail Beam Roller Plates

Justification

This project is justified on the requirement to rehabilitate failing or deteriorated control structure infrastructure in order for Hydro to provide safe, reliable flood management for the Bay d'Espoir reservoir system. Without a safe and reliable monorail system, scheduled maintenance would not be completed and refurbishment work would be delayed until the system is in operation. Delayed maintenance and refurbishments could result in the inability to open or close a gate. If the reservoir water elevations are rising and a gate is unable to be opened, spill capacity would be decreased, increasing the potential of overtopping and breaching the dam.

Alternatives

There is no alternative to replacement of the monorail beam and associated mounts. If the replacement of the monorail beam and hardware is deferred, deterioration will continue, thus decreasing the reliability of the overall structure. The safe and reliable operation of the monorail structure is critical to insert the stop logs during repairs, refurbishment, or maintenance to the gates.

Project Description

This project will replace the current monorail beam and associated mounts. The scope includes:

2022:

- Review content of the 2021 level 2 condition assessment and prepare engineering design and execution plan; and
- Commence procurement.

2023:

- Finish procurement activities;
- Execution of refurbishment activities for the monorail beam and associated mounts;
- Commissioning of existing monorail hoist on the new beam and associated mounts; and
- Close-out documentation.

The project will be executed in 2022–2023, with estimated costs of $579,400. Refer to Table 15 for the project estimate breakdown.

Project Estimates

Table 15 presents the project estimate for the Salmon River Spillway – Replace Monorail Beam and Associated Mounts project.

Table 15: Salmon River Spillway Replace Monorail Beam and Associated Mounts Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	90.0	0.0	**90.0**
Labour	48.4	53.8	0.0	**102.2**
Consultant	43.9	76.4	0.0	**120.3**
Contract Work	1.5	164.2	0.0	**165.7**
Other Direct Costs	1.9	3.1	0.0	**5.0**
Interest and Escalation	6.9	41.0	0.0	**47.9**
Contingency	9.6	38.7	0.0	**48.3**
Total	**112.2**	**467.2**	**0.0**	**579.4**

Project Schedule

The anticipated project schedule is shown in Table 16 for the Salmon River Spillway - Replace Monorail Beam and Associated Mounts project.

Table 16: Salmon River Spillway Replace Monorail Beam and Associated Mounts Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	January 2022	February 2022
Engineering:		
Develop requests for proposals for structural design support, engage consultant, and complete detailed design	April 2022	September 2022
Tender:		
Develop monorail assembly procurement package, tender and award package, develop Installation contract, and tender and award Installation contract	September 2022	February 2023
Procurement:		
Procure monorail beam assembly	October 2022	March 2023
Construction:		
Replace monorail beam assembly and commission trolley and hoist	July 2023	August 2023
Close Out:		
Close work order, complete all documentation, and complete lessons learned	September 2023	November 2023

Burnt Dam

Description of Equipment

The Burnt Dam Spillway Structure, located 133 km from Millertown, was placed into service in 1967. The spillway is a concrete structure equipped with two 7 m wide fixed wheel gates which operate under a maximum head of 8 m and are equipped with screw-stem hoists, as seen in Figure 14. Further information on the equipment is contained in Appendix A of the Asset Management Overview.

Figure 14: Burnt Dam Spillway

Current Status

In October 2017, a condition assessment was completed of the gates/embedded parts at the Burnt Dam Spillway. This inspection revealed deterioration with the gate hardware such as rollers, seals, screw stems, transfer cases. The inspection also revealed deterioration in the embedded parts such as concrete and roll paths. Figure 15 to Figure 17 highlight the deterioration in Burnt Dam.

Figure 15: Deformed Gate Knife – Burnt Dam

Figure 16: Rubbing Marks on Embedded Parts – Burnt Dam

Figure 17: Transfer Case Corrosion – Burnt Dam

Justification

This project is required to upgrade equipment in order for Hydro to provide safe, reliable flood management for the Burnt Pond Reservoir as well as fisheries compensation flow into the White Bear River.

Due to the high potential for flash flooding of the Burnt Pond Reservoir, operation of the Burnt Dam gates must be reliable in order to facilitate the safe control of water to avoid potential flooding damages. If the condition of the Burnt Dam gates continues to degrade, the risk associated with abnormal operation will increase. If the operation of either gate is impeded the results can create several scenarios including:

- Loss of reservoir capacity from an open stuck gate or broken dam fuse plug;
- Increase risk to the spillway structure and associated reservoir dams from increase stress on high flood levels; and
- Loss of water from the reservoir resulting in reduced generation from hydraulic fleet downstream.

Alternatives

Refurbishment is the only option to ensure reliable and effective operation of the spillway gates.

Project Description

This project is required for the refurbishment of Burnt Dam Spillway Bay 2 and is expected to take two years to complete and is estimate to cost $3,365,800. The first year (2022) will consist of engineering work while the scope of the second year (2023) will include the following:

- Work Zone Preparation: Once the stop logs are in place and the gate is safely raised, the work area will be prepared for dry work by installing a temporary bulkhead, tarps, and pumping system upstream of the sill. Scaffolding and accesses will be set up as well as temporary lifting systems for handling materials inside the bay.
- Demolition: Second stage concrete around the sill is expected to be partly demolished and prepared for repairs.
- Liner Plate Installation: Line plates to be welded and anchored to cover the second stage concrete area downstream of the sill.
- Upstream Reinforcement: Anchors to be installed on the upstream side of the embedded parts to improve their anchoring to concrete. Twelve anchors are estimated on each lateral side.
- Sill Concreting: Area downstream of the sill under the new liner plate to be concrete.
- Onsite Machining: On site machining equipment to be setup in each of the two lateral embedded parts for roll path, and guiding face machining over their entire length. Machining to be done to meet verticality and straightness criteria.
- Quality Checks and Survey: Precise surveying to confirm verticality and straightness of the lateral roll paths and guiding faces to be performed.
- Bay Demobilization: On site machining equipment, rails, and bracket to be dismantled and lifted outside the bay.
- Painting: The sill and lateral embedded parts surface to be prepared for recoating. Enclosures are expected to be set up to capture any debris, dust, or fumes coming from this operation. The surfaces would then be recoated.

- Screw Boot/Cover: Installation of a boot/cover on the gate screw stems to reduce airborne containments from accumulating on the screw stems.
- Testing and Commissioning: Commissioning the embedded parts to include testing gate operation in dry and wet conditions. A leakage rate test to be conducted.

Project Estimate

The estimate for the Refurbishment of Burnt Dam Spillway Bay 2 is presented in Table 17.

Table 17: Refurbishment of Burnt Dam Spillway Bay 2 Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	60.0	0.0	**60.0**
Labour	83.5	393.2	0.0	**476.7**
Consultant	148.9	67.1	0.0	**216.0**
Contract Work	212.5	1,697.5	0.0	**1910.0**
Other Direct Costs	8.1	22.5	0.0	**30.6**
Interest and Escalation	29.7	240.3	0.0	**270.0**
Contingency	49.9	352.6	0.0	**402.5**
Total	**532.6**	**2,833.2**	**0.0**	**3,365.8**

Project Schedule

Table 18 provides the anticipated project schedule for the Refurbishment of Burnt Dam Spillway Bay 2.

Table 18: Refurbishment of Burnt Dam Spillway Bay 2 Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	February 2022	May 2022
Procurement:		
Develop tender for consultants, tender, and award contract	March 2022	June 2022
Construction:		
Perform the refurbishment	July 2023	October 2023
Commissioning:		
Commission new equipment	October 2023	October 2023
Close Out:		
Project completion certificate and lessons learned	October 2023	November 2023

2.3 Reservoirs

Hydro is proposing to upgrade Public Safety Around Dams in 2022–2023.

2.3.1 Upgrade Public Safety Around Dams

Description of Equipment

Dams and waterways are critical assets for the hydraulic generation of electricity. A dam is a barrier that stops or restricts the flow of water, and waterways are structures that direct the flow of water. These assets require control measures to keep the public safe and informed of the impact these assets have on the surrounding area. Hydro undertakes the implementation of control and notification measures through its Public Safety Around Dams Program. For further information on the dams and waterways, refer to Appendix A in the Asset Management Overview which provides additional information related to the Public Safety Around Dams Program.

Over the past decade, an increase in noted public interactions with hydraulic generating structures, including access by recreational vehicles and boating near spilling gates, has prompted the development of this program in accordance with Canadian Dam Association Public Safety Around Dams Guidelines issued in 2011. The Canadian Dam Association's Public Safety Around Dams Guidelines are considered industry practice in Canada to increase Public Safety Around Dams and associated waterways.

Public safety risks are determined by completing risk assessments in accordance with the Canadian Dam Association's Dam Safety Guidelines. Appropriate control measures are installed to reduce the safety risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms and buoys, operational changes, and public education. The dams and waterways included in this proposal are:

- Bay d'Espoir: reservoir consists of dams, spillway structures, and an intake structure;
- Upper Salmon: reservoir consists of dams, control structure, spillway structures, and an intake structure; and
- Paradise River: reservoir consists of an arched dam, rock-filled dyke, and an intake structure.

Current Status

The Public Safety Around Dams risk assessments were completed at the Bay d'Espoir reservoir in 2011 and 2019; both assessments outlined areas that need to be addressed. Items identified in the 2011 assessment included fencing, signage, and waterway barriers such as booms and buoys and were installed in 2012. In 2019, the Long Pond reservoir was assessed again to verify the effectiveness of control measures, identify potential gaps or opportunities for improvement, and to account for any changes in public usage or facility operation that may change the associated risks. The 2019 assessment outlines areas that need to be addressed in 2022.

Risk assessments at the Upper Salmon Hydroelectric Generating Station ("Upper Salmon") were completed in 2017 which outlined areas that need to be addressed. Year 1 and Year 2 recommendations were completed in 2019 and 2020.

Risk assessments at the Paradise River Hydroelectric Generating Station ("Paradise River") were completed in 2019, which outlined areas that need to be addressed. Year 1 recommendations were completed in 2021.

Justification

This project is necessary to increase public safety for the Bay d'Espoir, Upper Salmon, and Paradise River dams and associated waterways.

Alternatives

Deferral of this project is not an acceptable solution as it is required for public safety. No other alternatives were considered.

Project Description

The scope of this project includes:

- Bay d'Espoir Year 1 Implementation: Year 1 for Bay d'Espoir will include the installation of fencing extensions and signage based on the 2019 assessment;
- Upper Salmon Year 3 Implementation: Year 3 for Upper Salmon will include the installation of safety boom and signage; and
- Paradise River Year 2 Implementation: Year 2 for Paradise River will include the installation of fencing and signage.

The project will be executed in 2022, with estimated costs of $469,500. Refer to Table 19 for the project estimate breakdown.

Project Estimate

The project estimate for the Upgrade Public Safety Around Dams project in 2022 is presented in Table 19.

Table 19: Upgrade Public Safety Around Dams Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	65.8	0.0	0.0	**65.8**
Labour	153.8	0.0	0.0	**153.8**
Consultant	29.7	0.0	0.0	**29.7**
Contract Work	122.2	0.0	0.0	**122.2**
Other Direct Costs	36.1	0.0	0.0	**36.1**
Interest and Escalation	27.7	0.0	0.0	**27.7**
Contingency	34.2	0.0	0.0	**34.2**
Total	**469.5**	**0.0**	**0.0**	**469.5**

Project Schedule

The anticipated project schedule for the Upgrade Public Safety Around Dams project in 2022 is presented in Table 20.

Table 20: Upgrade Public Safety Around Dams Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	February 2022	May 2022
Procurement:		
Special material requirements	March 2022	June 2022
Construction:		
Installation of public safety devices	June 2022	October 2022
Close Out:		
Project completion certificate and lessons learned	October 2022	November 2022

2.4 Site Buildings and Services Program

The following equipment upgrades and/or refurbishment for Site Buildings and Services are proposed for 2022–2023:

- Draft tube deck substructure level 2 condition assessment.

2.4.1 Draft Tube Deck Substructure Level 2 Condition Assessment

Description of Equipment

The Bay d'Espoir Hydroelectric Generating Facility is located on the south coast of the island portion of Newfoundland and Labrador. It was the first major hydroelectric project undertaken in the province and came into service in 1967. There are seven generating units at this facility; six units housed in Powerhouse 1 and one unit in Powerhouse 2, which utilize approximately 176 m of head to produce a rated output of 604 MW. The development produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island.

The draft tube deck with respect to Powerhouse 1 is located on the discharge side of the facility and spans between shore lines of the tailrace along the powerhouse wall. It is 97 m in length and is made up of reinforced concrete columns, pre-cast deck beams, and pre-cast deck slabs topped with a 6" concrete distribution slab and finished with 50 mm of asphalt. The draft tube deck includes the draft tube gate infrastructure and provides access for draft tube gate operation and maintenance. The draft tube deck surface also provides vehicular access to Unit 7 in Powerhouse 2 on the north end of Powerhouse 1. The deck was constructed in two phases. Phase 1, which consists of Unit 1 to Unit 4, was completed in 1966. Phase 2, which consists of Unit 5 and Unit 6, was completed in 1968.

Figure 18: Powerhouse 1 Draft Tube Deck as Viewed from the South End

Current Status

Refurbishment activities on the top deck were concluded in 2020 and consisted of addressing deck runoff issues and repairs to the exterior deck slabs. The majority of this work was completed in 2019 with the remainder completed in 2020. This refurbishment is the only major work that has been complete on the draft tube deck of Powerhouse 1 since it was originally constructed. Signs of deterioration such as concrete disintegration/spalling/delamination/cracking, rebar corrosion, efflorescence deposits, and scour from water erosion have been exhibited. The deterioration has also affected the operation and reliability of the draft tube gates. When installed, these gates often become lodged in the guides due to uneven guiding paths and a proper seal is difficult to achieve. An improper seal will not allow dewatering of the draft tubes, which prevents access to the draft tubes as well as the scroll case.

The substructure of the draft tube deck has not been the subject of any major repairs or refurbishments since its original construction.

Justification

This project is required to maintain reliable operation of the draft tube gate system for Bay d’Espoir Units 1–6 in Powerhouse 1. The proposed assessment will identify any deficiencies and establish the scope of refurbishment work necessary to extend the service life of the asset.

Alternatives

To determine the condition of the substructure and develop the scope of the refurbishment work, a condition assessment is the only alternative.

Project Description

The scope of this project includes completion of a level 2 condition assessment for the Bay d'Espoir Powerhouse 1 draft tube deck's substructure. The assessment will focus on the structural components, below the deck slab bearing elevation, including but not limited to:

- Pier cap beams;
- Pier columns;
- Powerhouse wall;
- Abutments; and

- Draft tube gate guides.

The project will be executed in 2022, with estimated costs of $343,600. Refer to Table 21 for the project estimate breakdown.

Project Estimate

The project estimate for the Draft Tube Deck Substructure Level 2 Condition Assessment in 2022 is presented in Table 21.

Table 21: Draft Tube Deck Substructure Level 2 Condition Assessment Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.5	0.0	0.0	**0.5**
Labour	83.4	0.0	0.0	**83.4**
Consultant	201.7	0.0	0.0	**201.7**
Contract Work	6.7	0.0	0.0	**6.7**
Other Direct Costs	4.3	0.0	0.0	**4.3**
Interest and Escalation	17.3	0.0	0.0	**17.3**
Contingency	29.7	0.0	0.0	**29.7**
Total	**343.6**	**0.0**	**0.0**	**343.6**

Project Schedule

The anticipated project schedule for the Draft Tube Deck Substructure Level 2 Condition Assessment in 2022 is presented in Table 22.

Table 22: Draft Tube Deck Substructure Level 2 Condition Assessment Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	January 2022	February 2022
Procurement:		
Prepare requests for proposals, tender, and award	February 2022	April 2022
Engineering Assessment:		
Perform assessment and develop methodology analysis	June 2022	October 2022
Close Out:		
Project completion certificate and lessons learned	November 2022	December 2022

2.5 Common Auxiliary Equipment

The following equipment upgrades and/or refurbishment for common auxiliary equipment are proposed for 2022–2023:

- Replace rotary strainer—Upper Salmon; and
- Communication link upgrade—Cat Arm.

2.5.1 Replace Rotary Strainer

Description of Equipment

The Upper Salmon Hydroelectric Generation Station utilizes a service water distribution system to supply critical plant systems which include the domestic water, cooling water, as well as shaft seal. Water is supplied to the service water distribution system by direct connection to the penstock. Initial filtration of the penstock water is completed through the use of a vertical rotary automatic backwash strainer equipped with an emergency bypass strainer, for use in the event the primary strainer becomes inoperable.

The rotary strainer is a R.P. Adams Co. vertical automatic backwash strainer with the capability to remove solids larger than 0.010" in size.

Current Status

The rotary strainer is original to Upper Salmon and is over 38 years old. The strainer is subjected to raw water with heavy organic material that can cause premature wear and organic buildup. In recent years, Hydro has undertaken work to change out cooling water lines downstream of the rotary strainer with stainless steel piping to reduce the impact of organic buildup in piping. The strainer is subjected to this organic buildup and all foreign debris that may be flowing through the inlet line form the penstock. The strainer is also showing signs of visible external corrosion with work completed in recent years due to blockages, alarm malfunctions and strainer flooding. Figure 19 illustrates this external corrosion on the body of the strainer.

Figure 19: Upper Salmon Rotary Strainer

Justification

If the rotary strainer is not replaced, the potential for premature fouling of new stainless lines installed downstream of the strainer will be increased. Continued use of the existing strainer may lead to inefficient filtration of raw penstock water for the service water distribution system, resulting in insufficient flow for the domestic water, cooling water, and shaft seal water systems, all of which are critical to plant operation. Limited flow to these systems can result in unplanned forced outages.

Alternatives

Replacement of this strainer is the only alternative; the strainer is past it is service life and requires replacement.

Project Description

The scope of the project includes:

2022:

- Engineering and technical specification development for a new service water distribution system rotary strainer, alarm equipment, electrical setup, and foundation modifications;
- Tendering; and
- Commence procurement.

2023:

- Completion of procurement activities;
- On site execution including removal of the in-service rotary strainer and associated equipment;
- Commissioning; and
- Close-out documentation.

This project will be executed in 2022–2023, with an estimate cost of $139,200. Refer to Table 23 for the project estimate breakdown.

Project Estimates

The project estimates for the Upper Salmon Rotary Strainer Replacement project in 2022–2023 is presented in Table 23.

Table 23: Upper Salmon Rotary Strainer Replacement Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	21.3	28.8	0.0	**50.1**
Labour	25.1	38.7	0.0	**63.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	1.3	2.9	0.0	**4.2**
Interest and Escalation	3.3	8.7	0.0	**12.0**
Contingency	3.1	6.0	0.0	**9.1**
Total	**54.1**	**85.1**	**0.0**	**139.2**

Project Schedule

The project schedule for the Upper Salmon Rotary Strainer Replacement project in 2022–2023 is presented in Table 24.

Table 24: Upper Salmon Rotary Strainer Replacement Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	March 2022	April 2022
Design:		
Develop specifications for strainers and tender the strainer with those specifications	May 2022	July 2022
Procurement:		
Award tender and confirm delivery date	August 2022	June 2023
Construction:		
Installation new strainer and commission	August 2023	August 2023
Close Out:		
Project completion certificate and lessons learned	November 2023	December 2023

2.5.2 Communication Link Upgrade

Description of Equipment

The station service line recloser provides an alternate source of station service to the powerhouse in an event power house station service is unavailable; this setup provides complete redundancy to the station service system.

The recloser is designed to operate when a close signal is sent from the control programmable logic controller ("PLC") indicating a dead bus on both the Cat Arm Unit 1 and Unit station service bus B1 and B2 respectively. The intake and accommodations power is supplied from the Coney Arm source through the station service line recloser under normal operation.

The existing control of the Cat Arm station service line recloser is via discrete copper signals from the station service switchboard. The copper signal travels partly underground and partly aerial connected through two outside junction boxes on both ends.

The station service switchboard contains a PLC which communicates with the Cooper Form 6 controller on the Coney Arm side to issue trip/close commands as well as monitor the status of the recloser. There is currently a pole mount transformer on the Coney Arm side of the recloser that provides power to the Form 6.

Current Status

The existing equipment uses hardwired copper cables which can become compromised by transient voltages caused power surges and lightning. These surges and spikes can cause permanent damage to the system over time. There have been several lightning events in recent years at the Cat Arm site which have impacted the station service system, thereby causing a loss of ac[4] power on the bus, which also resulted in powerhouse intake telecontrol system interruption.

Justification

This project is required to ensure reliable operation of the station service line recloser. If the station service line recloser operation becomes compromised, station service and communications to the plant will become interrupted, and thus remote visibility of critical plant equipment will be impacted. In a worse-case event, lightning could result in the damage of the stations service system, including the station service line recloser and controls.

Alternatives

Deferral of this project is not a viable option, as replacement of the hardwired recloser control with a fibre-optic connection is necessary to eliminate the risk of station service and communication failure resulting from compromised recloser operation.

Project Description

This project will replace hardwired control of the station service line recloser with a fiber-optic communication link.

- The RS-485 communication module installed in the Cooper Form 6 controller will be replaced by a fibre-based Ethernet port. The existing protection and controls hardware will be reused, and four interposing relays will be installed to interface the PLC input/output with the 129 Vdc control unit.

Additionally, this project involves the installation of a single-phase transformer on the bus side of the recloser to provide voltage sensing to the Form 6, and the controller will be configured to prevent live bus closing.

[4] Alternating current ("ac").

Project Estimates

The project estimate for the Cat Arm Communication Link Upgrade in 2022 is presented in Table 25.

Table 25: Cat Arm Communication Link Upgrade Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	12.6	0.0	0.0	**12.6**
Labour	65.3	0.0	0.0	**65.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	13.0	0.0	0.0	**13.0**
Other Direct Costs	8.3	0.0	0.0	**8.3**
Interest and Escalation	7.3	0.0	0.0	**7.3**
Contingency	9.9	0.0	0.0	**9.9**
Total	**116.4**	**0.0**	**0.0**	**116.4**

Project Schedule

The project schedule for the Cat Arm Communication Link Upgrade in 2022 is presented in Table 26.

Table 26: Cat Arm Communication Link Upgrade Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	February 2022	May 2022
Design:		
Design of communication upgrade	March 2022	April 2022
Procurement:		
Purchase all materials outlined in the design	April 2022	June 2022
Construction:		
Installation new system and commission	June 2022	September 2022
Close Out:		
Project completion certificate and lessons learned	November 2022	December 2022

3.0 Conclusion

This report provides information and justification related to the projects Hydro is proposing to undertake on its hydraulic generating units, structures, reservoirs, and common auxiliary equipment under its Hydraulic Generation Refurbishment and Modernization Program in 2022–2023.

3.1 Project Estimate

The overall project estimate total for all activities described in the Hydraulic Generation Refurbishment and Modernization (2022–2023) project is shown in Table 27.

Table 27: Hydraulic Generation Refurbishment and Modernization Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	491.8	198.3	0.0	**690.1**
Labour	1,127.9	743.0	0.0	**1,870.9**
Consultant	424.2	143.5	0.0	**567.7**
Contract Work	425.8	1,861.7	0.0	**2,287.5**
Other Direct Costs	84.1	72.3	0.0	**156.4**
Interest and Escalation	171.2	342.7	0.0	**513.9**
Contingency	245.6	427.4	0.0	**673.0**
Total	**2,970.6**	**3,788.9**	**0.0**	**6,759.5**

3.2 Project Schedule

Individual schedules for each activity are provided in Section 2.0 of this report. Typically, a high-level schedule for a multi-year project is as follows:

- Year 1: Planning, Design, and Procurement; and
- Year 2: Construction, Commissioning, and Close Out.

For one-year projects, all activities will be completed in one year. One-year projects typically have short material lead times and shorter construction requirements. Hydro anticipates all activities in this proposal to be completed before December 2023.

Attachment 1

2020 Capital Budget Application

Hydraulic Generation Asset Management Overview

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DAVE ROYLE
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7-23-19
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Hydraulic Generation Asset Management Overview

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has developed an ongoing capital program to replace or refurbish assets as they reach the end of their design life, or require attention due to obsolescence or anticipated failure.

Historically, Hydro's Hydraulic Generation projects could be divided into two categories; stand-alone, and programs. Programs include projects that are proposed year after year to address the need to upgrade or replace deteriorated equipment, such as control cables, and have similar justification each year. Stand-alone would include projects that do not meet the definition of a program. Hydro has had as many as 80 separate program-type projects in its capital budget applications over the past 5 years, with each stand-alone project tailored to a specific asset.

Starting with the 2018 Capital Budget Application ("CBA"), Hydro implemented a change to how the hydraulic generation programs are submitted for consideration by the Board of Commissioners of Public Utilities ("Board"). Hydro has consolidated the programs into the Hydraulic Generation Refurbishment and Modernization Project, thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro. This change will also allow Hydro opportunities to realize efficiencies by improving the coordination of capital and maintenance work on the Hydraulic Generation assets.

With the 2020 CBA, Hydro submits this updated version of the Hydraulic Generation Asset Management Overview ("Asset Management Overview") to provide an updated overview of Hydro's hydraulic generation asset maintenance philosophies into one document. Annually, beginning with the 2018 CBA, Hydro will propose the required projects specific to each year, referencing the Asset Management Overview document.

Contents

List of Appendices

1.0 Introduction

Hydro has 10 hydraulic electric generating stations. There are over 3000 assets involved in the operation of these stations.

Hydro has an Asset Management Program which governs the life cycle of its hydraulic generation assets. This program monitors, maintains, refurbishes, replaces and disposes of assets with the objective of providing safe, reliable electrical power in an environmentally responsible manner at least cost. Within this program, assets are grouped at each location by five asset classifications, including hydraulic generating units, hydraulic structures, reservoirs, site buildings and services, and auxiliary equipment. This allows asset management personnel to establish, where possible, consistent practices as it applies to equipment specification, placement, maintenance, refurbishment, replacement and disposal. These practices ensure that monitoring, assessing, justifying for capital refurbishment, and replacing for asset sustaining purposes are consistently executed. Hydro has established programs which enact these practices for assets or sub-grouping of assets, for example, turbine overhauls are performed on each hydraulic generating unit.

Part of Hydro’s Annual Capital Program is a sustained effort to ensure the safety and reliability of generation assets. Historically, the Board’s approval for this effort has been requested by Hydro submitting either individual projects for particular assets, or programs for hydraulic generation sustaining work in its CBA. This approach has resulted in a segmented view of the expenditures to sustain generation assets. For example, in the 2017 CBA, there were 14 projects submitted. The expenditures detailed in the projects according to the Board’s classifications are normal capital expenditures. Combining these projects into a Hydraulic Generation Asset Management Program provides an opportunity to increase regulatory efficiency and provide a more focused presentation of Hydro’s sustaining efforts for hydraulic generation.

With the 2018 CBA, Hydro consolidated planned Hydraulic Generation sustaining work into a project called Hydraulic Generation Refurbishment and Modernization Project (“Project”). Additionally, in the 2018 CBA, Hydro submitted a project titled “Hydraulic Generation In-Service Failures”, to cover the replacement or refurbishment of failed equipment, or incipient failures. Hydro is utilizing the Asset Management Overview as a reference for these projects to streamline and focus information submitted.

The Asset Management Overview provides supporting information which was, historically, presented annually for projects in a CBA. The remainder of this document provides information on the assets involved, a description of each asset, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

Hydro will update the Asset Management Overview each year as it implements changes to its asset management practices appropriate for inclusion in the Asset Management Overview.

1.1 Changes in Version 3

This report is Version 3 of the Asset Management Overview, submitted with the 2020 CBA. All material changes in this version are shaded in grey, and are summarized below:

- Section 4.4.9: Replace Unit Metering, Monitoring, Protection, SCADA and Control Assets Program
- This section has been updated to include the Air Gap Monitoring Program and Partial Discharge Monitoring Replacement Program.
- Section 4.5.3: Penstock Inspection Program
- This section has been added to highlight the Penstock Inspection Program that began in Bay d'Espoir and is continuing at other locations.

Minor changes to syntax have been made to improve readability. These minor changes have not been highlighted.

2.0 Hydraulic Generation Background

2.1 Hydraulic Generating Stations

The location, number of generators at each location, and the total rated generating capacity of Hydro's ten generating stations is as follows:

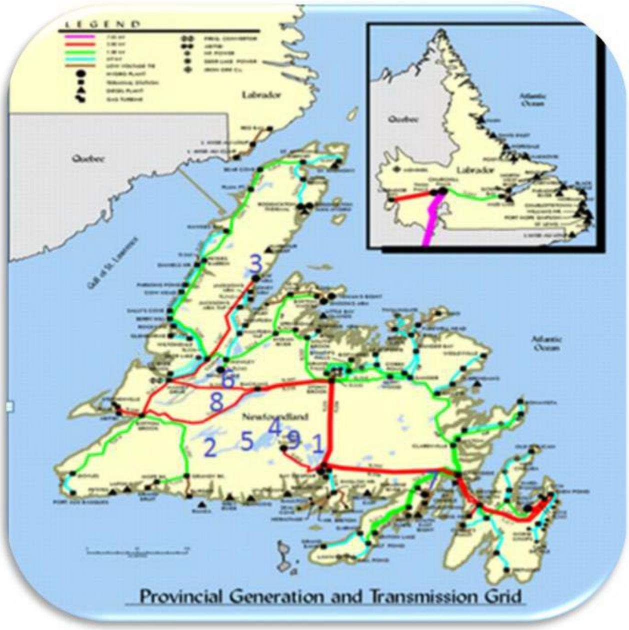
1) Bay d'Espoir ("BDE"), seven units in two powerhouses outputting 613.4 MW;
2) Cat Arm ("CAT"), two units outputting 134 MW;
3) Upper Salmon ("USL"), one unit outputting 84 MW;
4) Hinds Lake ("HLK"), one unit outputting 75 MW;

5) Granite Canal ("GCL"), one unit outputting 40 MW;
6) Paradise River ("PRV"), one unit outputting 8 MW;
7) Snook's Arm ("SAM"), one unit outputting 560 kW
8) Venams Bight ("VBT"), one unit outputting 340 kW; and
9) Roddickton ("RMH"), one unit outputting 440 kW.

Table 1 provides the in-service dates for each turbine generating unit.

Table 1: Turbine Generating Unit In-Service Dates

#	Location	In-Service Date
1	Paradise River	February 26, 1989
2	Bay d'Espoir Powerhouse 1	Unit 1: March 1967 Unit 2: June 1967 Unit 3: October 1967 Unit 4: September 1968 Unit 5: February 1970 Unit 6: March 1970
3	Bay d'Espoir Powerhouse 2	Unit 7: December 1977
4	Upper Salmon	January 1983
5	Granite Canal	August 2003
6	Snook's Arm	September 1957 (Acquired in 1968)
7	Venams Bight	April 1957 (Acquired in 1968)
8	Hinds Lake	December 1980
9	Cat Arm	Unit 1: February 1985 Unit 2: February 1985
10	Roddickton	December 1980



1. Bay d'Espoir – Powerhouses #1 & #2
2. Burnt Dam – Spillway Structure
3. Cat Arm - Powerhouse
4. Ebbegunbaeg – Control Structure
5. Granite Canal – Powerhouse
6. Hinds Lake - Powerhouse
7. Paradise River - Powerhouse
8. Star Lake - Powerhouse
9. Upper Salmon - Powerhouse

Figure 1: Hydraulic Generation and Structures Locations

2.2 Infrastructure Classifications

The approximately 3000 hydraulic generating assets are functionally grouped into hydraulic generating units (Section 4.4), hydraulic structures (Section 4.5), reservoirs (Section 4.6), site buildings and services (Section 4.7), and auxiliary equipment classifications (Section 4.8). A functional description and further sub-classification of the infrastructure, equipment and systems within these five asset classifications is provided in Appendix A: Full Asset Description.

3.0 Hydraulic Generation Capital Projects

3.1 Historical Hydraulic Generation Capital Projects

In the 2017 CBA, there were 14 individual Hydraulic Generation projects, which accounted for $13.1 Million, or 5 percent of the Capital Budget. Historically, Hydro's generating station projects were divided into two categories; stand-alone, and programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets, such as control cables, and have similar justification presented each year. Of the 14 individual Hydraulic Generation projects proposed in 2017, two were program- related and the 12 stand-alone projects were similar to projects submitted in previous CBAs and as such were continuing efforts to sustain hydraulic generating assets.

3.2 Hydro's Approach to Hydraulic Generation Capital Projects

The programs now included in the Project are:

- Hydraulic Generating Units Program;
- Hydraulic Structures Program;
- Reservoirs Program;
- Site Buildings and Services Program; and
- Common Auxiliary Equipment Program.

Items which will be excluded from the Hydraulic Generation Refurbishment and Modernization Project and be proposed separately include:

- Activities which cannot be scheduled for inclusion in the annual CBA. As these projects will be submitted as either a supplementary application or executed in the Hydraulic Generating Stations In-Service Failures Project.
- Activities in response to additional load or reliability requirements. As these projects generally have unique justifications, the projects will be proposed separately.
- Activities in response to significant isolated issues in a particular station, such as a replacement of a damaged turbine. As these projects generally have unique justification, the projects will be proposed separately.

Hydro will continue to maintain individual records with regards to asset capital, maintenance and retirement expenditures and performance, to support the development of the annual capital plan.

3.3 Benefits of the New Approach

Supporting information such as asset descriptions change infrequently. Referencing the Asset Management Overview in the Project documentation will eliminate the preparation and review of repetitious information. Hydro estimates that this approach could save up to $130,000[1] annually, not including time and costs for review by the Board and Intervenors.

[1] If the work to be undertaken in the 2018 Hydraulic Generation Refurbishment and Modernization Project had been submitted as 13 individual projects, its estimated preparation cost would be approximately $10,000 per project.

Hydro has a proactive Asset Management Program to anticipate future failures so that refurbishment or replacement can be incorporated into a CBA. However, there are situations were immediate refurbishment or replacement, which has not been included in a CBA, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure. This is necessary to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging assets, unanticipated failures are expected to increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a Hydraulic Generation In-Service Failures project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

Hydro expects the Hydraulic Generation Refurbishment and Modernization Project will provide opportunities whereby Hydro can further optimize the coordination of opportunities to optimize capital and maintenance work to minimize outages on equipment as personnel look to further coordinate work by location.

4.0 Asset Management Programs

4.1 Condition Assessment Practices

Hydraulic generation asset management personnel primarily obtain information to assess the condition of hydraulic generation assets through calendar-based or equipment operating time-based activities. Calendar-based activities include, but are not limited to, daily, weekly, monthly, quarterly, annual and three-year preventive maintenance procedures. Operating time-based activities include 500, 1000 or 2000-hour preventive maintenance procedures. More information on calendar based or equipment operating time based activities is presented in Appendix B: Operational Hour and Time Based Activity Background.

Capital overhauls and refurbishments are conducted on differing timeframes depending upon the asset, but range from approximately 6 to 25-year time frames. The actual timing of this work is determined by asset management personnel after considering various factors such as reliability, safety, frequency of operation, asset criticality, condition, operating constraints and geographic location. More information on how timing is determined is presented in Appendix C: Overhaul Timing Background.

The more frequent calendar-based and equipment operating time-based maintenance procedures consist of visual inspection of the equipment to look for abnormalities, such as noticeable cracks, rust, corrosion, electrical tracking, and component malfunction, as well as minor maintenance such as oil and filter changes, as required. The remaining preventive maintenance procedures and capital program activities require outages to the equipment and entail progressive levels of disassembly, checking, testing and adjustments of systems and components allowing for the identification of abnormalities which cannot otherwise be identified. These activities require greater or complete disassembly, specialized inspections and testing of equipment and, if required based upon condition assessment, unforeseen refurbishment or replacement activities completed within the approved budget for the program.

The condition assessment information, documented by the personnel executing these activities, is reviewed by Long Term Asset Planning personnel who determine if corrective action, either expensed as operating or included as capital, is required.

Additionally, Long Term Asset Planning personnel may initiate condition assessments of existing equipment and determine whether corrective action is required when information is obtained through different sources than those outlined above. These sources may include operating personnel, vendors, industry related groups and literature. This information may relate to such situations as changes to safety practices, reports of performance indicating that an asset is approaching end of service life, industry experience identifying new equipment issues, and manufacturers withdrawing product support (obsolete equipment) resulting in Hydro being unable to obtain spare parts and obtain technical expertise to maintain the equipment . Corrective actions may be required immediately, or may be executed at a future time. Condition assessment and practices specific to an asset classification are outlined in the corresponding program described later in the Asset Management Overview.

4.2 Program Types and Timing

The programs in the Asset Management Overview are primarily focused on the capital overhauls and the execution of corrective actions required by each asset classification. As the implementation of corrective action increases or is projected to increase, a program will be added to the Asset Management Overview. Due to the volume and complexity of hydraulic generation assets, capital corrective actions are required that do not warrant the establishment of a long-term capital program.

For each asset classification, these activities are captured under the section titled “Other Sustaining Activities”. Capital corrective actions that are aligned with the Asset Management Overview philosophies and practises as well as capital work which will result in economic savings, but do not reside within an established capital program, will be included in this program. Examples of capital work that could be included under Other Sustaining Activities are:

1) Deteriorated systems, equipment, components or material approaching the end of their service life;
2) Systems, equipment, and components for which manufacturers have withdrawn product support or industry experience has identified new performance issues;
3) Changes to safety practices on existing infrastructure; and
4) Replacement of existing assets with economically justified replacements.

In the Hydraulic Generation Refurbishment and Modernization Project submitted with each CBA, the “Other Sustaining Activities” items, with associated costs and a brief explanation of the work, will be provided for the Board’s review.

The timing of capital overhauls is determined by Long Term Asset Planning personnel after considering various factors including asset performance, safety concerns, frequency of operation, criticality, condition, corrective actions required, operating constraints and geographic location. More information on how timing is determined is presented in Appendix C. Execution of capital corrective actions which align with philosophies and practises outlined in the Asset Management Overview will be included in the “Hydraulic Generation Refurbishment and Modernization Project” or in the “Hydraulic Generation In-service Failures Project”. Immediate corrective actions stemming from an approved Hydraulic Generation Refurbishment and Modernization Project which can be accomplished within the project scope and budget may proceed within that project.[2] Future corrective actions would be included in the “Hydraulic Generation Refurbishment and Modernization Project” submitted in a future Capital Budget Application.

[2] Immediate action which cannot be accomplished within the scope and approved budget of an approved Hydraulic Generation Refurbishment and Modernization Project would be addressed either through the Hydraulic Generation In-Service Failures Project or through a Supplementary Capital Budget Application.

4.3 Asset Classification Description

Each asset classification section includes a high level functional description of the group's assets. More information about the infrastructure, systems, equipment, and components in an asset classification is provided in Appendix A: Full Asset Description.

4.4 Hydraulic Generating Units Asset Classification

Hydro's Hydraulic Generating Units Asset Classification consists of:

- Generators;
- Governors;
- Isolated Phase Buses;
- Spherical Valves;
- Turbines;
- Exciters; and
- Metering, Monitoring, SCADA, Protection and Control Equipment.

Figure 2 is a cross-section of a Hydraulic Generating Unit.

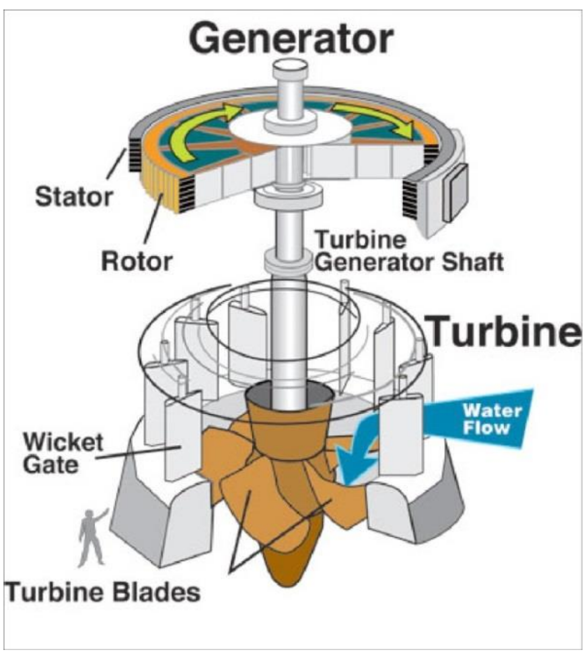


Figure 2: Hydraulic Generating Unit

Flowing water is directed from a penstock through a main inlet valve (where equipped) and into a spiral case, which encircles the turbine runner. The wicket gates direct water from the spiral case into the turbine runner (noted as turbine blades in Figure 2). The water turns the turbine runner and then flows into the draft tube attached to the turbine. The water passes through the draft tube and on to the tailrace to exit the generating station. A shaft connects the turbine runner and the generator rotor. Turning the runner causes the rotor to turn. Electrical interaction, created by the unit exciter system, between the stator and the moving rotor produces electricity for transmission to customers. A unit governor system controls the flow of water, by way of the wicket gates, to ensure an appropriate amount of water is passing through the turbine so as to supply the electrical power required from the generator. The electricity is passed from the generator to the electrical transmission system outside the hydraulic generation station through an electrical isolated phase bus system. Rotating equipment requires lubrication, so the unit has an automatic greasing system. Hydraulic generating units have protection, control, instrumentation, condition monitoring, SCADA[3] and metering equipment to ensure safe, reliable operation and asset management data for the unit.

Figure 3: Dismantled Generator

[3] Supervisory Control and Data Acquisition ("SCADA") systems gather information from the field, transfer the information back to a central site, alert the central site of abnormal system conditions, perform necessary analysis and control, and display information to operators. Operators interface with the SCADA which connects to equipment in the field.

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4.4.1 Turbine and Generator Six Year Overhauls Program

The Six-Year Overhaul involves a partial dismantling of the turbine and generator to inspect, test, clean, refurbish the units. This may entail replacing defective components and, as required, undertaking corrective refurbishment or replacement action. The generator activities involve activities such as cleaning and inspection of rotor and stator assembly, electrical testing on rotor/stator assembly and calibration and testing of turbine and generator protection devices. The turbine activities involve such activities as verification of bearing and seal clearances and testing and calibration of turbine protection, control and monitoring devices. During these overhauls, due to the dewatering of the unit, the draft tube and penstock are also inspected.

4.4.2 Turbine Major Refurbishment Program

The Turbine Major Refurbishment occurs on approximately a 15 to 25-year cycle and involves completely disassembling, inspecting, testing, assessing the turbine mechanical components and, as required, carrying out corrective work to refurbish or replace components to maintain the turbine performance until the next major refurbishment. As the unit is dismantled for the turbine major refurbishment, this offers an opportunity to carry out, if required, other sustaining work on the unit, including:

- Inspection and replacement, as required, of the head cover and bottom ring bushings;
- Inspection and, as required, replacement of the operating ring bearing;
- Replacement of wicket gate V packing;
- Replacement of various gaskets and seals;
- Refurbishment of runner due to cavitation damage;
- Machining of other unit surfaces as required based on condition assessments; and
- Testing and calibration of turbine protection, control and monitoring devices.

In the past, concrete growth in the turbine foundation and the resulting erosion caused movement of the turbine lower primary stationary seal. This could cause contact between the stationary and rotating seals and require a full dismantling of the unit to correct. Therefore, as required, grouting and machining of the upper and lower primary seals is also included in the Major Turbine Refurbishment.

4.4.3 Generator Refurbishment Program

Hydro’s generator stator windings have an anticipated service life of 40 years. As a unit approaches the end of its expected service life, a condition assessment is carried out. These assessments reveal signs of electrical deterioration such as seeping asphalt or cracked insulation, or mechanical deterioration such as shifting windings as a unit approaches the end of its useful life. At this point, Hydro takes action to replace the windings. Hydro undertook work to replace generator stator windings due to stator mechanical and electrical deterioration from 2009 to 2014. Future work of a similar nature will be completed within this program.

4.4.4 Spherical Valve By-Pass Refurbishment Program

Since 2013, Hydro has completed five spherical valve by-pass refurbishment projects due to deterioration and poor operating performance of the by-pass valve and control system. As the spherical valve by-pass reach the end of their service life, the valves begin to malfunction and become prone to failures due to seized internal components. Future work of this nature will be undertaken within this Program.

4.4.5 Exciter Replacement and Refurbishment Program

Hydro has undertaken ten exciter replacements due to a withdrawal of manufacturer product support. Future work to replace or refurbish existing exciters will be completed within this program.

4.4.6 Automate Generator Deluge Systems Program

Since 2013, Hydro has been automating the deluge systems at Bay d’Espoir. Future work to automate the remaining systems will be completed under this program.

4.4.7 Refurbish Generator Bearings Program

Since 2013, Hydro has been refurbishing the generator bearings and housings to eliminate oil loss from the bearing housing. Future work of this nature will occur under this program.

4.4.8 Replace Auto Greasing Systems Program

As the auto-greasing system on a generating unit ages, it becomes prone to issues such as solenoid failures, damaged timers and switches, and leaking tubing. On older units, the unavailability of replacement components makes maintenance of the systems difficult. Since 2013, Hydro has replaced six automatic greasing systems due to deterioration, incompatibility with new controllers, and on-going maintenance issues. This program will be used to undertake future work of this nature.

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4.4.9 Replace Unit Metering, Monitoring, Protection, SCADA and Control Assets Program

In 2016, the Bay d'Espoir Unit 7 vibration monitoring system was replaced to improve condition monitoring of Unit 7. The previously installed vibration monitoring system was unreliable. The new monitor has increased the diagnostic information available to asset management and maintenance personnel. Hydro plans additional work starting in 2018 to replace the other monitors on Bay d'Espoir Units 1 to 5 because the monitors are obsolete. The new monitors will allow long-term trending of data. Hydro will replace protective relays, annunciators, human-machine interfaces, other metering, monitoring, protection, and control equipment as it becomes obsolete, fails or operate unreliably, to ensure reliable operation of protective devices.

In 2017, a multi-year project to install a new Asset Health Monitor system, for Upper Salmon, started. The new Asset Health Monitor system will gather diagnostic data from the generating unit and provide trending analysis for asset management and maintenance personnel. Hydro plans additional work starting in 2018 to replace obsolete monitoring devices on Bay d'Espoir Units 1 to 5.
In 2017, Hydro identified control cables in its Hydraulic Generating Station are leaking oil, which is contaminated with PCB's. In 2018, Hydro will start a five year effort to replace the cables and, if required, associated infrastructure.

Air Gap Monitoring measures the gap between the rotor and the stator on a Hydroelectric Generating Unit. Changes in air gap can be influenced by operating conditions such as shaft oscillation, vibration, magnetic and hydraulic forces. Starting in 2009 and continuing to 2014 units 1-4 in Bay d'Espoir have had the stators rewound, see section 4.4.3 of this report. During this work air gap monitors were added to the units for online real time monitoring of the air gaps. Online monitoring of the air gap between the rotor and stator can provide significant and timely information about its physical condition as it changes over time and with different operating conditions.

In 2020, Hydro has proposed to rewind Unit 5 in Bay d'Espoir and add air gap monitoring to this unit. This monitoring device requires a partial dismantle of Unit 5 and is done during the rewind for labour efficiencies associated with unit dismantling. This program will be used to undertake future work of this nature.

In 2020, also combined with the Unit 5 Stator Rewind Project, Partial Discharge ("PD") Monitoring will be upgraded on Unit 5. PD analysis is used to determine the rate and level of degradation of stator insulation. PD Monitoring along with Air Gap Monitoring upgrades are done with this rewind project for labour efficiencies associated with unit dismantling. This program will be used to undertake future work of this nature.

Hydro expects additional replacement of metering, monitoring, protection, and control equipment assets, including wiring, panels and other supporting materials and devices, due to deterioration and obsolescence; and to provide more functional equipment. Work of this nature will be covered by this program.

4.4.10 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing.

4.5 Hydraulic Structures Asset Classification

Hydro's Hydraulic Structures Asset Classification consists of:

- Control Gates;
- Penstocks;
- Surge tanks; and
- Remote Water Level Systems.

Figure 4 is a cross-section of a hydroelectric installation showing the intake gate.

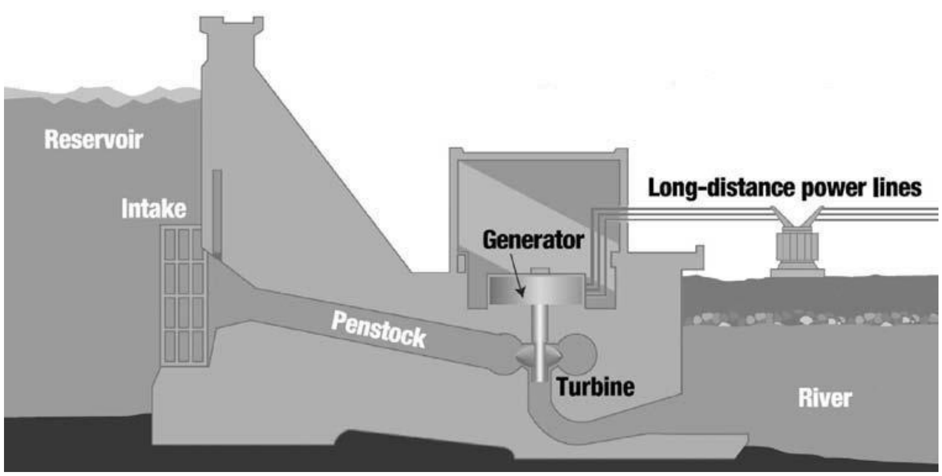

Figure 4: Cross-Section of Intake

Hydro uses hydraulic control structures to control the flow of water from reservoirs. Structures associated with a powerhouse intake control the flow of water from the reservoir into penstocks which transport water to a hydraulic generating unit (shown as a turbine and a generator in Figure 4) to produce electricity. Structures associated with a spillway control the flow of water from the reservoir into a spillway ("Spilling"). Spilling, when required, is done to avoid damage to the reservoir dams or dykes caused by excessive water in the reservoir. Hydro's control structures consist of structural, mechanical, and electrical systems. The water flows through the concrete structures and the mechanical systems incorporated into the concrete structure. The mechanical systems controlling the flow of water include vertical sliding gate, a gate hoist, gate rollers, seals, and embedded steel parts in the concrete to allow movement of the gate by the hoist. Electrical systems include heaters to prevent icing of the mechanical systems in the concrete structure, power supply systems and control systems for the gate equipment. The stoplogs are mechanical systems of wood or steel members placed by lifting devices between control structures and the reservoirs so as to stop water from flowing through the concrete structures when the mechanical gate systems are being worked upon. Hydro has 21 hydraulic control structures, which incorporate 40 gates.

Figure 5: West Salmon Spillway Control Structure

A penstock is a large pipe, most commonly constructed of welded steel, which conveys water from a reservoir to turbine. Serving the hydraulic units Hydro has eight steel and one wood stave penstock and three arrangements with penstock/power tunnel combinations.

Some hydraulic generating stations, with high head designs, have surge tanks are connected to penstocks to neutralize the impact of sudden changes in pressure on the penstock caused by operation of the station. Water flows into the tank when the penstock water pressure increases and out of the tank when penstock pressure decreases, thus mitigating the effects of water hammer on a penstock. Hydro has four surge tanks in two hydraulic generating stations.

Figure 6: Surge Tanks at the Bay d'Espoir Hydraulic Generation Station

The primary preventive maintenance procedure for Hydraulic Structures is a yearly inspection. Based upon condition, overhauls are performed on a 10-15 year frequency.

4.5.1 Refurbishment and Replacement of Control Gates Infrastructure Program

Failure of subcomponents of control structures can result in safety hazards, equipment damage, or the inability to operate gates as required. The failure of the gate control system has resulted in the filling of the penstock too quickly, creating hazardous conditions; the failure of gate heaters can result in mechanical components freezing, resulting in their failure to operate. Since 2009, Hydro has undertaken control gate refurbishments in Hinds Lake, Upper Salmon, and Bay d'Espoir for intake structures and at Salmon River, Victoria and Burnt Dam for spillway structures. This work has included structural, mechanical, electrical and control system work. Future refurbishment work will be executed through this program.

4.5.2 Refurbish Surge Tanks Program

Hydro carries out progressive inspections monthly and annually on surge tanks, and a major inspection every six years. Based on these inspections, Hydro determines whether corrective action is required. Over time, protective coatings degrade, resulting in increased corrosion which, if left unmitigated, may result in leaks or structural failure of the tanks. Failure of the cathodic protection and protective coating of the surge tanks resulted in corrosion on the Bay d'Espoir assets. In 2014, 2015, and 2016, Hydro completed projects to refurbish the surge tanks. Future refurbishment work on any surge tanks will be covered by this program.

4.5.3 Penstock Inspection Program

Issues experienced with Bay d'Espoir Penstocks 1-3 in 2016 and 2017 have compelled Hydro to make significant changes to its inspection frequency and scope for all hydraulic unit penstocks. Gaps were found in penstock inspection frequency for all Hydro's penstocks. Penstock inspection frequency was determined with assistance from ASCE Steel Penstocks, 2012 manual as well as CEATI Penstock Inspection 2017 report. Using criteria set out by both of these organizations for comprehensive internal inspections, Hydro has set up a framework to carry out internal inspections for all penstocks.

4.5.4 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing.

4.6 Reservoirs Asset Classification

Hydro's Hydraulic Reservoirs Asset Classification consists of:

- Dams;

- Dykes;
- Power canals;
- Spillways;
- Control weirs;
- Fuse plugs;
- Tunnels;
- Instrumentation; and
- Public safety control measures.

Figure 7 is a general cross-section of an embankment type dam.

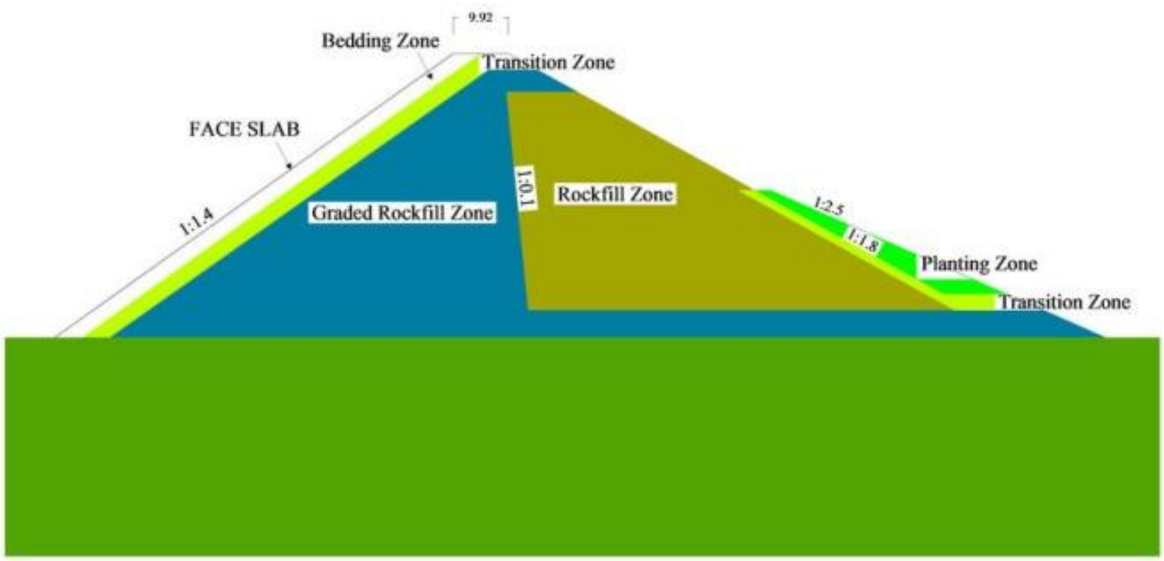

Figure 7: Dam Cross-Section

Dams and dykes are constructed to increase the storage capacity of the reservoir. The majority of Hydro's dams are embankment type structures. The largest structure is 63m high. Power canals are typically a dyke lined canal developed to convey water between reservoirs, or from a reservoir to an intake structure. Passive overflow spillways are dams that are built to spill water from a reservoir at a specific elevation. Overflow spillways in Hydro's system are constructed of rock fill with steel sheet pile cores, concrete or timber crib. Control Weirs are low head concrete overflow spillways that maintain the water elevation upstream of the weir to within a specified range. Fuse plugs are sections of dams that are constructed of earth materials and designed to fail in a controlled manner without damaging adjacent larger, more critical dams. Power tunnels convey water, through rock, from a reservoir to an intake structure. Diversion tunnels divert water around the work site. Dam instrumentation provides measurements for comparison to the dams design criteria.

Figure 8: Hinds Lake Power Canal

Hydro has approximately 80 dykes and major structures in this classification. Hydro carries out preventive maintenance activities at various frequencies for different asset types. For instance, dam-type assets are visually inspected biweekly and undergo semi-annual engineering inspections.

Figure 9: Safety Boom and Signage

4.6.1 Upgrade Public Safety around Dams and Waterways Program

Public safety risks are determined by completing risk assessments in accordance with the Canadian Dam Association's Dam Safety Guidelines, 2007 that includes guidelines for public safety and security around dams. Appropriate control measures are then installed to reduce the safety risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms and buoys (as shown in Figure 9), operational changes and public education. Hydro has conducted seven public safety projects since 2011. Future work to further enhance public safety around Hydro dams and waterways will be undertaken through this program.

4.6.2 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing

4.7 Site Buildings and Services Asset Classification

Hydro's Site Buildings and Services Asset Classification consists of:

- Water distribution systems;
- Fuel storage and distribution systems;
- Powerhouse buildings;
- Service buildings;
- Helicopter Pads;
- Site fencing and gate controls;
- Parking lots;
- Stairways; and
- Site access roads.

Figure 10: Paradise River Generating Station

Water distribution systems collect, transmit, treat, store, and distribute domestic water. Fuel storage and distribution systems handle diesel, helicopter, and gasoline fuels. Powerhouse buildings contain the hydraulic generating unit and the unit auxiliary mechanical and electrical equipment. Service buildings are other building required for a hydraulic generating station, which includes warehouses, maintenance buildings, training facilities, site accommodations, and security offices. Helicopter pads allow helicopters to use relatively flat, clearly marked hard surfaces away from obstacles to land and take off safely. All sites have fencing and/or gates with controls to maintain site security and public safety. The parking lots and stairways provide vehicle parking and safe access to facilities. Site and access roads allow access to hydraulic generation locations, such as generating stations and dams.

Site Buildings and Services assets are inspected and, where applicable, tested annually.

4.7.1 Access Road Refurbishment Program

Since 2010, Hydro has undertaken four projects to refurbish access roads to its hydraulic generating stations to maintain safe access to Hydro sites. Refurbishment was necessary due to deterioration caused by insufficient drainage, washouts, or the need for additional road topping material. Hydro expects to undertake similar work in the future and will execute it within this program.

4.7.2 Diesel Fuel Storage Refurbishment and Replacement Program

Hydro has 19 diesel fuel storage tanks at its hydroelectric generating stations. These are subject to deterioration, such as reduced wall thickness and corrosion discovered during routine tank inspections. Tanks are also subject changing government regulations. Hydro will use this program to refurbish or replace tanks when deteriorated and to comply with Government regulations. Hydro has tanks in remote locations and since 2007 has installed remote monitoring on some of those tanks. If required to add remote monitoring to other tanks, Hydro will undertake this work within this program.

4.7.3 Draft Tube Deck Refurbishment Program

A draft tube deck is a common feature in a hydroelectric plant. The draft tube is where the exhausted water from the hydro unit exits and is directed to the tailrace. The draft tube deck is a reference to the full structure including the substructure, exit water channels, and the deck above that can be driven over or has walk access to install draft tube gates. Draft tube gates are used to isolate the hydro unit by preventing tailrace water from coming back up through the unit. For Example: The draft tube deck in Bay d'Espoir is 97 meters long, and is made up of reinforced concrete columns, pre-cast deck beams and pre-cast deck slabs, topped with a six inch concrete distribution slab and finished with 50 mm of asphalt. The structure allows for vehicles to access Powerhouse 2 on site and the substructure of the deck channels water from the draft tube of the hydro unit to the tailrace.

Over time concrete degrades and the structure experiences wear due to weather and water erosion. Once this damage occurs, refurbishment of the structures is required to ensure the reliable operation of the hydro units. Future refurbishment work on any Draft Tube Deck will be covered by this program.

4.7.4 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing

4.8 Common Auxiliary Equipment Asset Classification

Hydro's Common Auxiliary Equipment Asset Classification consists of:

- Station service;
- Ancillary AC/DC electrical system;
- Standby diesel generators;
- Cranes;
- Fire protection and detection systems;
- Powerhouse public address systems;
- Compressed air systems;
- Service/cooling water systems;
- Domestic water systems;
- Drainage/unwatering systems;
- Water level systems;
- Heating, ventilation, and air conditioning systems;
- Waste oil storage tanks; and
- Lube oil storage.

Figure 11 is a picture of the Bay d'Espoir Station Service Transformers. This is one of many examples of auxiliary equipment required for Hydro's daily operations.

Figure 11: Bay D'Espoir– Station Service Transformers

Station service system uses transformers and other equipment to convert AC electricity to a voltage acceptable for use in the ancillary AC/DC electrical system which distributes electricity to ancillary equipment needed in the operation of the hydraulic generating station. Standby diesel generators are installed at locations that require electricity for operations, for use if the primary power supply is interrupted. Cranes are used during maintenance and capital work. Fire protection and detection systems are installed to protect people, buildings, power transformers, generators, and other equipment. Powerhouse public address systems allow communication within a noise working environment. Compressed air systems provide pressurized air to equipment that requires pressurized air to operate, such as governors, and spherical valves. Service/cooling water systems are used to remove heat from turbines and generators, particularly bearings and generator stators. Domestic water systems supply water where water is needed. Drainage/Unwatering Systems remove water from the hydraulic generating unit to allow access to the turbine. Water level systems provide water level monitoring in streams, lakes or reservoirs. Air conditioners control the temperature for personnel and equipment.

Heating, ventilation and air conditioning ("HVAC") systems also provide humidity control for humidity-sensitive electrical equipment. Ventilation systems remove waste heat generated by generating units, and circulate fresh air using ducts and fans. Waste oil storage tanks hold used oil for disposal. Lube oil storage are laydown areas for the 200 litre drums of lube oil that are located at most generating stations.

There is a mixture of time based preventive maintenance procedures ranging from weekly to yearly, and a mixture of operational hour preventive maintenance procedures ranging from 500 to 2000 hour checks used to assess and maintain these assets.

4.8.1 Station Service Refurbishment and Replacement Program

Station service systems in Hydraulic Generating Stations are complex systems comprised of a number of subsystems. Devices such as reclosers and circuit breakers require replacement as they become obsolete, resulting in the unavailability of replacement parts required to maintain equipment or operate unreliably. Equipment may require replacement to reduce fault levels, and arc-flash levels, or improve protection coordination, either of which may result in safety hazards or equipment damage if left unmitigated. Electrical equipment, such as transformers, is prone to insulation breakdown and other deterioration as it reaches the end of useful service life and require refurbishment or replacement. In 2015, 2016 and 2017, station service electrical equipment was replaced at Cat Arm and Bay d'Espoir due to operational failures, deterioration, and weak protective coordination between devices. Hydro expects work like this will occur in the future and will undertake that work under this program.

4.8.2 Service/Cooling Water Refurbishment and Replacement Program

Over time, cooling water pipes can become clogged with organic slime and hardened organics that attach themselves to the pipe walls causing the cooling water flows to decrease significantly. Additionally, older cooling water pipes are constructed of mild steel, which is prone to corrosion over time. Since 2009, Hydro has undertaken 11 projects to replace cooling systems and piping, pump, and instrumentation components due to pipe fouling from material build up and corrosion. Future capital work on service/cooling water systems will be undertaken within this program.

4.8.3 Air Conditioning Refurbishment and Replacement Program

Hydro has refurbished or replaced air conditioning systems and improved ventilation in four projects due to obsolescence, resulting in the unavailability of replacement components require to maintain units. Air conditioning systems are also replaced or upgraded due to increased cooling requirements. Future capital work for this will be executed through this program.

4.8.4 Standby Generator Refurbishment and Replacement Program

Since 2009, Hydro has replaced three standby generators at Bay d'Espoir due to poor performance and the inability to reliably supply station service power in an emergency. Primary power diesel generators have been replaced at the Burnt Dam and Victoria Control Structure locations. Diesel generators require an engine overhaul based on operating hours and operating performance. Typically, standby diesels rarely require this refurbishment and primary power diesel generators require this refurbishment about every five years. Future replacement and refurbishments of diesel generators will be completed under this program.

4.8.5 Ancillary AC/DC Electrical System Refurbishment and Replacement Program

In 2011 and 2013, Automatic Transfer Switches were replaced at Bay d'Espoir and Hinds Lake due to operational failures. In 2015, Hydro started the installation of Infrared Inspection Viewports in electrical equipment at various hydraulic generating stations to allow safe inspection of the equipment while energized. Installations of the viewports will occur under this Program. In addition, Hydro expects that the replacement and refurbishment of ancillary AC/DC electrical assets will continue to maintain a reliable supply of electricity. In the future, this work will occur under this program.

4.8.6 Other Sustaining Activities - Common Auxiliary Equipment Program

As described in Section 4.2 Program Types and Timing

Appendix A

Full Asset Description

Hydraulic Generating Units

Generator

A generator is an electric rotating machine that transforms mechanical power from a hydraulic turbine into electric power.

Stator Assembly

A stator consists of a core and a frame; it is the stationary part of a machine that serves as both a magnetic circuit and a supporting member. The core is made up of sheets of electrical steel; the sheets, which are 0.35–0.5 mm thick and insulated with varnish, are formed into stacks and fastened in the cast or welded frame. Stator windings fit into slots made in the core. The stator is cooled with surface air coolers, which are heat exchangers that have cooling water flowing through which cool the hot air blown around the stator.

Rotor Assembly

The rotor consists of a fabricated spider, laminated rim, field poles and windings, a brake ring and collector rings.

Thrust and Guide Bearing

The thrust and guide bearing combination on the generator sustains axial and lateral loading and prevents axial and lateral movement. The bearing consists of a segmented guide bearing, thrust block, rotating ring, segmented spring-supported thrust bearing, base ring, oil reservoir, cooling coils, alarm devises, and a high pressure oil injection system for start-up (if equipped).

Cooling Water System

The cooling water system supplies water to the thrust and guide bearing cooling coil to cool the oil reservoir. The cooling water also supplies the surface air coolers in the generator to cool the stator and rotor by air circulation within the generator.

Governor

The governor serves to keep the speed of the hydro unit constant in order to maintain the systems frequency of 60 hertz. Any change in load or other operational disturbances will cause the governor to open or close the wicket gates to allow more or less water to maintain the constant speed of the Hydro Unit.

Governor Speed Generators

Speed control is one of the primary functions of a governor. On Mechanical governors, a set of rotating flyballs, opposed by a spring, controls the position of a valve. The valve controls the flow of oil to a servomotor that controls the wicket gates. Any change in speed will cause the valve to be moved off its centered position, making the gates open or close, and changing the unit's speed. Modern electronic governors control the gates by monitoring electronic signals from speed sensors.

Governor Pump

The pump used by the governor to port oil through the governing system.

Governor Piping System

The network of pipes required to deliver the governor oil to the desired location.

Accumulator Tank

An accumulator tank stores oil for the governor system and is pressurized by air.

Servomotor Assembly

The servomotors are hydraulically actuated pistons, controlled by the governor, that move the linkages connected to the wicket gates to allow water regulation to the hydraulic generating unit to maintain a constant speed.

Isolated Phase Bus

Isolated phase bus is the current carrying conductors used to transmit large currents. For Hydro’s generation sites, it is the means used to carry the current from the generators to the step-up transformers. The conductors are individually contained within housings to provide electrical and physical protection and to minimize the possibility of faults.

Disconnect Switch

Disconnect switches are used to electrically isolate the isolated phase bus either for maintenance activities or troubleshooting. Proper operation of these switches is essential for the establishment of a safe work environment and for reliable and secure system operation.

Grounding Switch

Grounding switches are used to provide a safe and secure electrical connection between a piece of equipment and ground. Proper grounding of equipment is essential for the establishment of a safe work environment.

Buswork

Buswork is the current carrying conductors which provide connections for the electrical circuits.

Main Inlet Valve

Main Inlet Valves are mainly employed in power plants with more than one generating unit sharing a common penstock. When one penstock is used to supply two or more generating units these valves are installed on each unit to provide isolation from the penstock water supply. This allows the operation of one unit while the other unit is down for maintenance or in stand-by. Most of Hydro's Main Inlet Valves are of the spherical valve type.

Turbine

A turbine is a rotary machine that converts kinetic energy and potential energy of water into mechanical work. Components of the turbine include:

Runner

Flowing water is directed on to the blades of a turbine runner, creating a force on the blades. Since the runner is spinning, the force acts through a distance, which is the definition of work. In this way, energy is transferred from the water flow to the turbine.

Draft Tube

In power turbines a diffuser tube is installed at the exit of the runner, known as draft tube.

Guide Bearing

The guide bearing on the turbine sustains lateral loading and prevents lateral movement. The bearing consists of a segmented guide bearing, oil reservoir, cooling coils, and instrumentation to monitor bearing temperature and oil levels within acceptable ranges.

Auto-greasing System

The auto-greasing system delivers controlled amounts of lubricant to multiple locations on a hydraulic generating unit while the machine is in operation.

Turbine Shaft and Coupling

The turbine shaft is the portion of the hydraulic units' shaft that is connected to the turbine. The shaft coupling joins the generator shaft to the turbine shaft.

Scroll Case

A spiral-shaped steel intake guiding the flow into the wicket gates located just prior to the turbine.

Headcover Assembly

The headcover is the top stationary part of a hydraulic turbine that encloses the system.

Wicket Gates and Linkages

Adjustable elements that control the flow of water from the scroll case into the turbine passage by the linkages connected to the servomotors.

Excitation

Excitation Transformer

The excitation transformer is a part of the excitation system. It is used to convert the generator terminal voltage to a lower voltage which supplies the rectifier. The excitation system creates the DC energy for the rotating magnetic field in the generator to enable conversion of mechanical energy into electrical energy. Without an excitation transformer, a generating unit is not able to produce electricity.

Field Breaker

The field breaker is a circuit breaker used to isolate the power supply between the excitation system and the generator rotor. The field breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of the field breaker through its fast response and complete interruption of current flow is essential for the protection of the excitation system.

Metering, Monitoring, Protection, SCADA and Control

Ground Cubicle

Minimizes fault damage incurred by generators, and maintains sufficient fault detection to improve power system reliability.

Auto Control Panel

The auto control panels are where control or monitoring instruments are displayed. This is where operators interface with the generating unit.

Synchronizing Panel

Synchronization panels are mainly designed and used to meet power system requirements. These panels function both manually and with an automatic synchronizing function for one or more generators or breakers. They are widely used in synchronizing generators.

Temperature and Frequency Control Panel

This panel displays the temperature and frequency of the hydro unit.

Time and Frequency Clock

Highly sensitive equipment used to measure the time and frequency of the unit.

Oscillogragh

An Oscillogragh is a device for recording oscillations, especially those of an electric current.

Voltage and Megawatt Panel

This panel displays the voltage and megawatt output from the hydro unit.

Recorder

The recorder records the voltage and megawatt readings of the unit.

Control Cables and Junction Boxes

Control cables connect various circuits for the operation of each generator. Junction boxes are also located along cable paths where it is practical to terminate cables from various sources.

Vibration Monitoring System

Hydro Unit systems

For Hydro Units vibration sensors are mounted on the critical bearings and wired to the plants computer system or to a dedicated vibration monitoring system. Two alarm levels (soft and trip) are then set to alert the operator that maintenance attention is needed or in the case of a Trip Alarm to shut the machine down to prevent failure.

Handheld Units

Handheld vibration units use magnetic vibration sensors that are directly connected to the equipment to monitor vibration and record data. This data can then be downloaded to a computer for analysis.

Data Acquisition System

This system measures an electrical or physical phenomenon such as voltage, current, temperature, pressure, or sound with a computer. The system consists of sensors, measurement hardware, and a computer with programmable software.

Hydraulic Structure

Substructure

The substructure is the underlying or supporting structure, such as the concrete foundation.

Superstructure

The superstructure is the components of a hydraulic structure that are on top of the substructure. This includes components such as the structural steel, hoists and motors for the gates.

Gates

The structure gates are designed to hold back water. In a spillway the water is on one side and the other side is typically dry when the gates are closed. Depending on the function of the particular structure, the gates are opened to move water from one reservoir to another, or to spill water from the reservoir when the water level exceeds the maximum safe level.

Stoplogs/Master logs

The stoplogs are a set of wooden or steel logs that are put in place by a crane or hoist with the help of a lifting device called the master log. The stop logs act as a temporary measure to isolate the water side of the gate for maintenance.

Gate Hoist

A gate hoist is a device used for lifting or lowering a gate by means of a drum or lift-wheel around which a wire rope or chain wraps.

Gate Rollers, seals, and embedded parts

The gate rollers are attached to the gate and roll along the embedded steel in the gains.

Heating Systems

There are three heating systems that can be used in a structure; the first is a gain heater that heats the roller path on the side of the structure and ensures the roller path is free of ice during the winter.. Sill heaters heat the bottom of the gate where it sits on the concrete substructure so that the gate does not freeze to the bottom during winter. The other heating system is on the gate itself and is called gate heaters. Gate heaters are used to ensure that ice does not form inside the gate and that water side of the gate is free of ice during the winter.

Control Systems

Control systems are typically computer systems designed to control gate systems remotely. Some older technology electronic controllers are used for specific simple control features.

De-icing Systems

In conjunction with the heating systems pother systems are strategically employed to combat ice around gates. Water up lifters are used to agitate the water close to the surface of the gate to inhibit the formation of ice. Bubbler systems use compressed air to lift warmer water at lower levels in the reservoir to prevent the formation of ice cover or to remove ice build-up on trash racks.

Penstock

A penstock is a channel for conveying water to a turbine, commonly constructed of steel, wood, or rock.

Surge Tank

A surge tank is a tank connected to a penstock carrying reservoir water. It is intended to neutralize sudden changes of pressure in the flow by filling when the pressure increases and emptying when it drops to minimize the effects of water hammer in a penstock.

Heating Systems

The surge tank heating system prevents the stagnant water in the surge tank from freezing in the winter. If surge tank water freezes, water can’t flow freely to avoid water hammer.

Relief Valves

Relief values are an alternative to Surge Tanks to minimize the effects of water hammer in a penstock. The use of a Surge Tank or a relief valve is determined during the design stage of a new unit and it is typically not possible to change the design after initial construction.

Coating Systems

Metal penstocks are coated to protect the steel and welds from corrosion due to the water inside and the elements outside of the penstock or Surge Tank.

Drainage Systems

Drain pipes are installed under the penstocks in the bedding material to collect any leakage from the penstocks as well as surface water and any leakage from the intakes/dams.

Water Level Systems

Water level systems are located at hydraulic structures to provide information to operations to make informed decisions about water management and other operating conditions.

Reservoirs

Dams and Dykes

Hydro currently operates more than 100 dams, dykes and hydraulic structures on the island of Newfoundland. Hydro dams are constructed to hold back water and raise its level in order to contain water for electricity generation. The majority of Hydro's dams are embankment type structures with our highest structure being 63m high.

Power canals

Power canals are typically a dyke lined canal developed to convey water from one reservoir to another or form a reservoir to an intake structure.

Passive Overflow Spillways

Passive overflow spillways are dams which are built to spill water from a reservoir at a specific elevation. Overflow spillways in our Hydro system are constructed of rock fill with steel sheet pile cores, concrete or timber crib.

Control Weirs

Control Weirs are low head concrete overflow spillways which maintain the water elevation upstream of the weir to within a specified range.

Fuse Plugs

Fuse plugs are sections of dams that are constructed of earth materials and designed to fail in a controlled manner without damaging adjacent larger more critical dams.

Power Tunnels

Power tunnels convey water, through rock, from an intake structure to a generating station.

Diversion Tunnels

Diversion tunnels divert water around the work site.

Dam Instrumentation

This instrumentation monitors the dam design criteria. Examples of dam instrumentation include piezometers, inclinometers, survey monuments and anemometers. This condition monitoring instrumentation is used to measure movement of the dam structure and water content in the dam.

Public Safety Around Dams Control Measures

Public safety risks are determined by completing risk assessment in accordance with Canadian Dam Association ("CDA") guidelines for Public Safety Around Dams. Control measures are then recommended to reduce the risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms, buoys, operational changes and public education.

Site Buildings and Services

Water Distribution System

A water distribution system is a system for the collection, transmission, treatment, storage and distribution of water from source to site locations.

Piping

The network of pipes required to deliver the site water to the site facilities.

Pumps

The driver of the water from the source is by pumps.

Storage Tanks

Storage tanks hold water to provide a consistent water pressure at site facilities and a volume of water that can be used for firefighting.

Filters

To remove sediment and fine particles from the water filtration systems are used.

Fuel Storage and Distribution System

Fuel Storage and Distribution System are site specific systems to have fuel and distribution methods on site.

Diesel Fuel Tank

Tanks that house diesel fuel only.

Gasoline Fuel Tank

Tanks that house gasoline fuel only.

Jet Fuel Tank

Tanks that house jet fuel only.

Fuel Dispenser and Pumps

Apparatus used to dispense and meter the fuel.

Powerhouse Building

Buildings used to house hydraulic generating units and the auxiliary mechanical and electrical equipment required for the generation of electricity.

Vertical Lift Equipment Doors

Vertical Lift Doors are large doors that allow access to the powerhouse building for large material and equipment. The doors are operated manually or electrically by a counter weight arrangement.

Roof

The roof is the structure forming the upper covering of a powerhouse building.

Substructure

The substructure is the underlying concrete support of the powerhouse.

Superstructure

The superstructure is the building that is placed upon the substructure. This includes the concrete and steel that make up the walls of the building.

Service Buildings

Service buildings are any other building on site that supports Hydro’s generation of electricity. This includes warehouses, maintenance buildings, training facilities, site accommodations, and security facilities.

Substructure

The substructure is the underlying concrete support of the service building.

Superstructure

The superstructure is the building that is placed upon the substructure.

Septic System

A septic system stores and distributes sewage. This includes a septic tank, septic field and all associated distribution piping.

Garage Doors

A garage doors is a large door on a service building that opens either manually or by an electric motor. These are typically overhead doors similar to automotive garages or residential attached garages.

Exhaust Systems (Welding)

Wielding exhaust systems are ventilation systems, in maintenance buildings, that specifically circulate fresh air using ducts and fans in the area to ensure worker safety.

Ventilation Systems

Ventilation systems circulate fresh air using ducts and fans.

Security Systems

A security system detects and issues an alarm due to an intrusion or unauthorized entry. Security systems are also used to prevent unauthorized access to Hydro facilities.

Helicopter Pad (“Helipad”)

A helipad is a landing area or platform for helicopters and powered lift aircraft. While helicopters and powered lift aircraft are able to operate on a variety of relatively flat surfaces, a fabricated helipad provides a clearly marked hard surface away from obstacles where such aircraft can land safely.

Site Fencing and Gate Controls

All sites have fencing and or gates with control to maintain site security and public safety.

Parking Lots and Stairways

The parking lots and stairways are areas for staff, contractors and the general public to park vehicles for safe access to Hydro’s facilities.

Site and Access Roads

Site and Access Roads are used to allow access to specific locations, such as generating stations, terminal station, hydroelectric dam, and all Hydro locations.

Drainage

Drainage is the sloping of land to divert water away from a specific area.

Culverts

Culverts allow the passage of water through/under a road.

Bridge

Bridges are structures used to span sections of site roads over a stream, river, valley, canal, or any obstacle preventing access to the site location.

Common Auxiliary Equipment

Station Service

A station service switchboard is an electrical panel used to supply low voltage power to the critical and auxiliary electrical equipment necessary for the operation of the generating units. The protective devices included within the station service switchboards are required to monitor the flow of electricity and to interrupt this flow, in a selective and timely manner, in the event of an electrical fault.

Station Service Transformers

Station Service Transformers convert electricity from higher voltages to voltages used in the ancillary AC/DC Electrical system.

Circuit Breakers

Circuit breakers perform switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers is essential for the protection of the critical and auxiliary equipment supplied by the station service switchboard.

Disconnects and Switches

Disconnects and switches are used to electrically isolate equipment for maintenance activities or troubleshooting. Proper operation of these switches is essential for the establishment of a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnects or switches that do not operate properly create a safety hazard.

Grounding Transformers

Grounding transformers are used to provide a ground path for the station service systems. This ground path ensures that the system's neutral is at or near ground potential. The establishment of a suitable ground enables safe operation of a grounded electrical system, and allows protective devices (like relays or low voltage circuit breakers) to detect and isolate line-to-ground faults.

Instrumentation Transformers

Instrument transformers are used to provide inputs to protection, control and metering equipment required for protection of the electrical equipment supplied from the station service system.

Surge Arrestors

Surge arresters provide overvoltage protection of electrical equipment from lightning and switching surges.

Power Cables and Junction Boxes

Cables to connect station service to switchgear and electrical panels and ancillary equipment. Junction boxes are also located along cable paths where it is practical to terminate cables from various sources.

Ancillary AC/DC electrical system

Switchgear and Panels

Switchgear and Panels are devices which are used to distribute electricity to cables. This equipment protects the cables and equipment from overload and short circuits.

Power Cables and Junction Boxes

Distributes electricity to equipment

Battery Banks and Chargers

Provides DC electricity for DC powered equipment.

Diesel Standby Generator

A diesel generator is the combination of a diesel engine with an electric to generate electrical energy. Prime-power diesels provide power to sites that are not connected to an interconnected distribution system. Emergency diesels are on stand-by at various locations within Hydro’s system to ensure system reliability.

Engine

This is the diesel engine used to drive the genset.

Generator

The generator converts mechanical energy from the engine to electricity.

Enclosure

Some diesels are located outside and require an enclosure to house the unit away from the weather.

Cranes

Cranes are machines used for moving heavy objects, typically by suspending them from a projecting arm or beam.

Overhead

An overhead crane consists of parallel runways with a traveling bridge spanning the gap. A hoist, the lifting component of a crane, travels along the bridge.

Monorail

A traveling crane suspended from a single rail.

Gantry

Gantry cranes are a type of crane built atop a gantry, which is a structure used to straddle an object or workspace

Wire Rope

Wire rope is a length of rope made from wires twisted together as strands.

Fire Protection and Detection System

A fire alarm system has a number of devices working together to detect and warn people through visual and audio devices when smoke, fire, carbon monoxide or other emergencies are present.

Transformer Deluge System

A transformer deluge fire sprinkler system is an automated water spray system where the water distribution piping is equipped with open spray nozzles for discharging over a transformer. Deluge systems are connected to a water supply through a deluge valve that is opened by the operation of a smoke or heat detection system.

Fire Panels

A Fire Alarm Control Panel, or Fire Alarm Control Unit, is the controlling component of a Fire Alarm System.

Generator Deluge System

A generator deluge fire sprinkler system is an automated water spray system where the water distribution piping is equipped with open spray nozzles for discharging within the generator. Deluge systems are connected to a water supply through a deluge valve that is opened by the operation of a smoke or heat detection system.

Inergen System

Inergen agent is a mixture of three naturally occurring gases: nitrogen, argon, and carbon dioxide. This system releases the Inergen agent when the system is activated and floods the contained room with the agent to extinguish the fire by decreasing the oxygen concentration below levels required to sustain combustion.

Office Sprinkler System

An office space sprinkler system is a system for protecting a building against fire by means of overhead pipes which convey water to heat-activated outlets.

Passive Fire Protection

Passive fire protection is an integral component of the three components of structural fire protection and fire safety in a building. This protection is used to contain fires or slow the spread of fires.

Powerhouse Public Address System

A public address system is an electronic sound amplification and distribution system with a microphone, amplifier and loudspeakers, used to allow a communication within a loud powerhouse.

Compressed Air System

Compressed air is air kept under a pressure that is greater than atmospheric pressure.

Air Receiver Tank

This is the tank for where the pressurized air is stored until it is required.

Air Dryer

An air dryer is used for removing water vapor from compressed air. The process of air compression concentrates atmospheric contaminants, including water vapor. This raises the dew point of the compressed air relative to free atmospheric air and leads to condensation within pipes as the compressed air cools downstream of the compressor.

Excessive water in compressed air, in either the liquid or vapor phase, can cause a variety of operational problems for equipment using the compressed air. These include freezing of outdoor air lines, corrosion in piping and equipment, malfunctioning of pneumatic process control instruments, fouling of processes and products, and more.

Compressors

A machine used to supply air at increased pressure.

Service/Cooling Water System

Service or Cooling water is the water removing heat from a machine or system.

Pumps

Cooling water pumps distribute the water from the source to the system.

Basket Strainers

Cooling water is sourced from the tailrace or other unfiltered sources and the basket strainer is a closed vessel with cleanable screen element designed to remove and retain foreign particles down to 0.001 inch diameter from various flowing fluids

Piping, valves, and controls

The piping, valves and controls are required components of the cooling water system.

Domestic Water System

Domestic water use is water used for indoor and outdoor site purposes such as washrooms, and kitchens.

Drainage/Unwatering System

This system handles the removal of water from the hydraulic generating unit draft tube for maintenance.

Sump Pumps

The pumping system required to remove the water.

Water Level System

Water level or gauge height or stage is the elevation water in a reservoir.

Air Conditioners

Air conditioners control the temperature in many locations for personnel and equipment. The units also provide humidity control in rooms with sensitive electrical equipment like communication rooms.

Ventilation System

Ventilation systems circulate fresh air using ducts and fans.

PCB Waste Oil and Waste Oil Tanks

These are specifically marked oil tanks that only contain waste oil, once the tanks are full a waste disposal company will come to site to empty the tank. PCB waste oil has to be disposed of properly outside of the province this is why there are two types of waste oil storage.

Lube Oil Storage

Lubrication oil storage includes laydown areas for the 200 litre drums that are located at most generating stations, carrying devices for these drums, and smaller storage containers that are used for top-ups when required. The proper storage for lube oil is important to equipment health because a proper container will limit any air borne particulates or any moisture from contaminating the oil.

Appendix B

Operational Hour and Time Based Activity Background

Time Based Activities

Time based maintenance is maintenance performed on equipment based on a calendar schedule that is planned in advance. Hydro's Time Based PM includes:

- Daily operational checks – running maintenance
- PM 1: Weekly Checks
- PM 2: Bi-Weekly Checks
- PM 3: Monthly Checks
- PM 4: Quarterly Checks
- 120 Day Transformer Inspection
- PM 5: Semi-Annual Checks
- PM 6: Yearly Checks
- PM 8: 3 Year Checks
- PM 9: 6 Year Checks

Note: All the PM checks except for the PM 9 are operating expenditures.

Operational Hour Activities

Operational Hour Preventative Maintenance is performed based on the actual usage time of the piece of equipment. This applies to auxiliary equipment such as compressors that have operational time checks at:

- 500 Hour PM
- 1000 Hour PM
- 2000 Hour PM

Note: All the time based PMs are operating expenditures.

For each Time Based and Operational Hour activity listed specific check sheets has been developed for each asset classification, such as mechanical, electrical, and P&C. On each check sheet, there are specific checks and duties that have to be completed. If abnormalities, such as unexpected wear on a runner, are found, then they are reported to the Long Term Asset Planning group who assessed the condition and, if required, determine the corrective action and timing. This work may or may not require capital expenditures.

Appendix C

Overhaul Timing Background

newfoundland labrador hydro
a nalcor energy company

Major Equipment and Structural Overhauls

Major Equipment and Structural Overhauls are required on assets to ensure safe reliable operation. For Major Equipment and Structural Overhauls the timing is nominally between 6 and 25 year frequency. Some examples are:

- Generating Unit Major Overhauls, approximately every 6 years
- Generating Unit Turbine Refurbishments, approximately every 15 - 25 years
- Control Structure Major Overhauls, approximately every 10 years
- Intakes, Spillways, and Bypasses Major Overhauls, approximately every 15 years

To determine the timing and the tasks in each overhaul, information such as the following is reviewed:

1) Timing
   - Is the unit overhaul required at this time (based on equipment condition)?;
   - Is there sufficient generation is available on the electrical system to allow the outage?; and
   - Will any spilling of reservoir water occur during the time the outage is required?
2) Condition

   There are two types of assessments that LTAP use to determine the condition of an asset, Class 1 or Class 2 assessments:
   - Class 1 Assessments

     These assessments are completed using information from condition monitoring or during maintenance procedures.
   - Class 2 Assessments

     These assessments are completed using information from detailed, extensive asset inspection or testing. The information is obtained through overhauls conducted and investigations completed by people with specialized expertise. The activities required can involve advanced testing and or disassembly of equipment to perform a inspections and testing.

3) Asset Criticality

Asset management personnel have ranked hydraulic generation assets criticality. This ranking is used in determining the priority of work in a given year.

4) Frequency of Operation

An asset that is used more frequently will require more maintenance, both preventative and corrective, therefore a unit that is used more will have overhauls scheduled more frequently.

5) Safety

Projects that have safety justifications are given high priority.

6) Reliability

Overhauls can be performed earlier for the units that exhibit poor reliability.

7) Geographical Location

The maintenance center for Hydro Generation is located in Bay d'Espoir. When work is required at stations or structures outside the Bay d'Espoir area plans are developed to pool many activities together to increase efficiency.

Tab 2: Thermal
In-Service Failures

2022 Capital Budget Application

Thermal In-Service Failures (2022)

July 2021

A report to the Board of Commissioners of Public Utilities

Contents

List of Appendices

Thermal In-Service Failures (2022)

Category: Generation – Thermal Plant

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and avoid unsafe working conditions due to equipment failure. One of the primary objectives of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in its annual capital budget application. This is achieved through the preventive maintenance program using various condition-based assessments and testing procedures.

Generally, Hydro identifies the refurbishment and replacement work that will be required in time for inclusion in its capital budget applications. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an imminent failure, or identification of faster than anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, corrosion, wear of mechanical components, etc.

Hydro is proposing this project to secure its ability to undertake immediate capital refurbishment and replacement work[1] that may become required for its Holyrood Thermal Generating Station ("Holyrood TGS") to maintain safe and reliable operations and to ensure the availability of capital spares[2] required to support such work. Examples of the activities that may be undertaken in this project are outlined in Appendix A. Hydro has used historical data and the professional judgement of its asset management personnel to determine the budget for this project.

[1] This project excludes work which can be executed as either Unforeseen or Capital Budget Supplemental projects.
[2] Capital spares are major spare parts that meet the definition of capital assets that are kept on hand to be used in the event of an unexpected breakdown or failure of equipment, thereby expediting the equipment's return to service. Capital spares are important in reducing periods of interruption in the generation and transmission of electricity.

2.0 Background

The 2020 Thermal In-Service Failures project supported the completion of 29 corrective actions, as outlined in Appendix A. The total expenditure for this project in 2019 was approximately $1.8 million.

3.0 Project Justification

Due to the age and operational requirements of the Holyrood TGS systems and equipment, equipment failures and deterioration will occur. This project provides an effective and timely means for Hydro to undertake the immediate capital refurbishment and replacement work required for the Holyrood TGS to maintain safe and reliable operations and to ensure the availability of capital spares required to support such work. Deferral of the type of work that is typically completed under this project could result in a detrimental impact to customer power supply or an unacceptable risk to safety.

4.0 Project Description

Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for the Holyrood TGS to maintain safe and reliable operations and ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions; however, throughout 2022, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to avoid deficiencies in its capital spares inventory.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	350.0	0.0	0.0	**350.0**
Labour	822.5	0.0	0.0	**822.5**
Consultant	20.0	0.0	0.0	**20.0**
Contract Work	704.4	0.0	0.0	**704.4**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	103.1	0.0	0.0	**103.1**
Contingency	0.0	0.0	0.0	**0.0**
Total	**2,000.0**	**0.0**	**0.0**	**2,000.0**

As there is no planned refurbishment work, replacement work, or capital spares acquisitions, no project schedule is provided for those activities.

Work executed under this project in 2022 will be reported to the Board in Hydro's 2022 Capital Expenditures and Carryover Report and provided in 2023 as part of the 2024 Capital Budget Application.

5.0 Conclusion

The Thermal In-Service Failures project allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. This project will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support thermal generation operations.

Appendix A

2020 In-Service Failure Activities

Table A-1: 2020 In-Service Failure Activities

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Waste Water Treatment Building Roof Replacement Holyrood TGS	275.7	The Waste Water Treatment Plant ("WWTP") was installed in 1992 and there have been no major upgrades to the roof since its original installation. The WWTP processes effluent from the periodic basin which originates from air heater washes, boiler washes, batch reactor waste, and landfill leachate. In 2020, a large leak was identified in the roof of the WWTP. Upon investigating the leak, it was discovered that the roof failed and required a full replacement, to prevent damage to the equipment housed in the building.	The WWTP roof replacement commenced in 2020. All materials were received and a contractor from Nova Scotia mobilized to execute the work. Due to changing COVID-19 protocols and poor weather conditions, the work was paused at 5% completion and will resume in 2021 when weather conditions are favorable. A contingency plan was implemented to temporarily protect equipment inside the building during the 2020–2021 operating season.
Cooling Water Outfall Pipe Replacement Holyrood Unit 3	244.3	In 2020, sink holes were discovered in the vicinity of the Unit 3 circulating water discharge line from the seal pit to the outfall into Holyrood Bay. This indicated a leak in the cooling water discharge line, which was subsequently confirmed with a dye test. A consultant was engaged and an inspection of the pipeline was completed during the Unit 3 annual outage in 2020. It was confirmed that a section of the discharge pipe, below where the sinkhole appeared, is in poor condition and must be replaced. The consultant recommended installing a new pipe section inside the existing 84 inch pipeline.	Materials and equipment have been procured and a contract is in place to execute cooling water outfall pipe replacement. The work requires a total plant outage to obtain the necessary isolations to perform the work safely and is planned to be completed during the 2021 total plant outage.
West Boiler Feed Pump ("BFP") Replacement Holyrood Unit 1	162.9	In 2020, the Unit 1 west BFP seized during operation; the shaft was prevented from spinning and the rotor locked. This caused an induced current in the motor resulting in significant overheating and damage to the rotor's squirrel cage bars.	The west BFP volute and motor for Unit 1 were replaced with available spare components.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Variable Frequency Drive Cell Spares Replacement Holyrood TGS	112.3	Nineteen Boiler Forced Draft Fan Variable Frequency Drive cells failed in service in 2020. These failures did not affect production as there is redundancy built into the system to account for failures.	The failed variable frequency drive cells were replaced using available spares. The failed cells were refurbished and returned to inventory as spares.
Feedwater Valves Overhaul Holyrood Unit 3	107.1	BFP provide high pressure feedwater to the boiler during operation by taking feedwater from the deaerator storage tank and pumping it through the high pressure feedwater heaters, economizer, and into the boiler steam drum. The feedwater is then converted into superheated steam in the boiler which then flows to the steam turbine. Feedwater systems are controlled with valves to regulate flow to the boiler, based on operating loads and the amount of water needed to feed the boiler for steam production. During unit operation, the feedwater control valves were observed to be passing fluid while in the closed position. During the Unit 3 annual outage, the valves were disassembled and it was determined that wear on main internal sealing components was causing both valves to pass fluid.	The Unit 3 feedwater control valves were overhauled.
East Fuel Oil Pump Replacement Holyrood Unit 1 West Fuel Oil Pump Replacement Holyrood Unit 2	104.3	The Unit 1 East and Unit 2 West fuel oil pumps were found to be worn by abrasives inherent in Bunker C heavy fuel and no longer able to meet operating requirements.	The Unit 1 East and Unit 2 West fuel oil pumps were replaced during the annual unit outages.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Stack Winch System Replacement Holyrood TGS	94.6	Each of the three boiler exhaust stacks has a mid-way platform which contains an environmental monitoring station, providing continuous emissions monitoring ("CEM") of carbon monoxide, carbon dioxide, nitrous oxide, sulfur dioxide and oxygen. As required by federal regulations and the plant's certificate to operate, a third party completes a yearly test on the CEM equipment to ensure it is measuring accurately. Tools and equipment used to service and test the CEMs are brought to the mid-way platform using the stack winch system.	Stack Winch System Replacement, Holyrood Thermal Generating Station.
Extraction Pumps Expansion Joints Replacement Holyrood Unit 3	91.5	After steam passes through the low pressure stage of the turbine, it forms condensate and collects in the condenser. The Unit 3 extraction pumps draw liquid condensate from the condenser and pump it through low pressure heat exchangers before recycling it back to the boiler for steam production. Both pumps are required to be in-service to achieve full loading of Unit 3. The expansion joints are installed between the condenser outlet piping and the pump's suction inlet to accommodate vertical and horizontal movement caused by heating and cooling cycles. The expansion joints had deteriorated over time causing them to crack and leak, which caused air to be drawn into the line through the cracks. This caused increased backpressure in the condenser which affected the unit's ability to reach full load.	The Unit 3 extraction pumps expansion joints were replaced.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
East and West Cooling Water Pump Motor Refurbishment Holyrood Unit 1 East Cooling Water Pump Motor Refurbishment Holyrood Unit 3	88.5	During the annual inspections on the Unit 1 East and West Cooling Water Pump motors and the Unit 3 East Cooling Water Pump motor, the megger test readings were low, indicating that the winding insulation had deteriorated to the point where there was high risk of a short circuit between the windings or the windings and the ground. An overhaul of each motor was required to restore the insulation integrity.	The cooling water pump motors were refurbished, including: removal of contamination by a special cleaning process; heat drying and special painting of the stator and rotor electrical windings; retesting of the windings and resistance temperature detectors; and replacement of the motor roller bearings.
Fire Hydrants and Valves Replacement Holyrood TGS	83.8	In 2020, two fire hydrants failed and required replacement. In addition, the valves in the fire water distribution lines, which are used to isolate the Bunker C fuel tank farm and the light oil tanks, failed and required replacement.	The failed fire hydrants and isolation valves were replaced.
Low Load Control Valve Replacement Holyrood Unit 2	75.9	The BFPs provide high pressure feedwater to the boiler during operation. The low load control valve on the Unit 2 BFP system was found to be leaking during start-up in 2020, which contributed to the unit's failed start-up attempt. Disassembly and inspection identified deterioration of the valve's major internal components (plug and seat ring). The damaged components could not be repaired.	The Unit 2 low load control valve damaged components were replaced with available spares during the annual Unit 2 outage.
Compressor 1 and 2 Oil and Cooler Replacement Holyrood TGS	48.5	Operational data for Compressors 1 and 2 showed an upward trend in oil temperatures. This prompted an inspection which revealed that the compressor oil coolers were fouled and approaching failure.	The compressor oil and cooler were replaced for Compressor 1. The compressor oil, cooler and shaft seals were replaced for Compressor 2.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Boardwalk Refurbishment Holyrood Marine Terminal	42.6	In 2020, heavy rainfall caused washouts along the embankment upon which the marine terminal boardwalk is constructed. The washouts caused large rocks, trees and ground to slide into several structural supports of the wooden boardwalk which led to collapse in some areas.	The marine terminal boardwalk structural supports were refurbished and the embankment was shored up.
Jetty Capstan Gear Box Refurbishment Holyrood Marine Terminal	34.2	The Holyrood Thermal Generating Station receives approximately 10–12 shipments of Bunker C fuel oil via tanker ships annually. The tanker ships dock at the fuel offloading facility and are secured into position via six capstans during the fuel offloading process. The six capstans are equipped with electrically driven gearboxes to secure the mooring lines for the tanker ship. All six capstans are required to be in operation in order to safely dock the ships.	Jetty Capstan Gear Box Refurbishment, Holyrood Marine Terminal
Spare Fire Water Pump Procurement Holyrood TGS	29.5	In 2019, the electric fire pump was taken out of service to repair a packing leak and damage was discovered to the shaft, bearings, and seals. The jockey pump was also inspected and found to have major cavitation damage on the internal components.	The electric driven fire pump was refurbished in 2019 to replace the damaged internal components. The jockey pump was replaced in 2019 with an available spare pump.
Air Heater Header Pressure Control Valve Overhaul Holyrood Unit 1	26.5	The Unit 1 Air Heater Header Pressure Control Valve failed during operation and an assessment during the annual outage determined that the valve internal components required replacement and the valve actuator required an overhaul and calibration.	The Unit 1 Air Heater Header Pressure Control Valve and its actuator were overhauled during the unit outage and calibrated during unit startup.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Fuel Oil Suction Strainers Replacement Holyrood Units 1 and 2	26.0	The fuel oil suction strainers are on the inlet supply to the fuel oil heating and pumping sets which are fed from the main fuel oil tanks. They are the last filter to capture foreign components before they enter the fuel oil pumps, fuel oil heaters, piping and boiler burner system (burner tips). The strainers are duplex basket type which means there are two parallel basket housing compartments. At any given time, only one strainer is in service and the other strainer is isolated to allow basket removal and cleaning while online. The Units 1 and 2 fuel oil suction strainers are 1969 vintage equipment and the internal sealing components of the strainers were worn over time, making it difficult to obtain a seal between the left and right sides of the strainer housings.	The Unit 1 and 2 fuel oil strainers were replaced during the Unit 1 and 2 annual outages.
Spare West Boiler Feedwater Pump Motor Procurement Holyrood Unit 2	24.3	The west boiler feedwater pump motor failed in 2019.	The failed feedwater pump motor for Unit 2 was replaced with an available spare in 2019. A new motor was ordered and received in 2020 to replace the spare.
Spare Hydraulic Servo Valves Procurement Holyrood Units 1 and 2	22.9	Unit 1 tripped off line in 2018 as a result of turbine steam control valves closing without receiving the command from the control system. An investigation concluded that hydraulic system contamination was the cause of the unit trip. Hydro proceeded to refurbish the hydraulic system on Unit 1. The Unit 2 hydraulic system is identical to that for Unit 1 and, while no failures had occurred, Hydro determined it was reasonable to expect that the system for Unit 2 was in the same contaminated condition as for Unit 1. The refurbishment of Unit 1 hydraulic system consumed all of the spares in the standby pool. A review of the component failure rate resulted in an update to the standby spare strategy to increase the required number of available spares.	In 2018 and 2019, the hydraulic systems for the Unit 1 and Unit 2 control valves were refurbished. Spare hydraulic servo valves for the Unit 1 and Unit 2 turbine hydraulic system were ordered in 2019 and received in 2020.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Air Heater Condensate Control Valves Replacement Holyrood Unit 3	20.9	During the 2019/2020 operating season, plant operations were unable to control the condensate tank level within the required set points for Unit 3. Investigation confirmed that the main control valve and bypass valves had failed and were passing condensate.	The failed air heater condensate control valves for Unit 3 were replaced.
Air Heater Condensate Check Valve Replacement Holyrood Unit 1	20.8	Steam Coil Air Heaters ("SCAH") are used to add heat to incoming boiler combustion air at lower loads to ensure exhaust gas temperatures stay elevated. The condensate check valve on the Unit 1 air heater system failed during the 2019–2020 operating season due to water hammer. The bolted head bonnet on the check valve failed and was leaking condensate which posed a safety risk. The extent of the damage was beyond repair.	The Unit 1 air heater condensate check valve was replaced during the annual outage.
South Vacuum Pump Inlet Valve Replacement Holyrood Unit 3	19.4	During the 2019–2020 operating season, the inlet valve on the Unit 3 South Vacuum Pump began experiencing operational issues. The motorized butterfly valve is operated remotely from the control room. When the pump is started or stopped from the control room, the valve is supposed to automatically open or close, but the valve consistently jammed when tested. Repairs could not be completed because the valve is obsolete and replacement parts are no longer available.	The inlet valve for the Unit 3 South Vacuum Pump was replaced.
Low Pressure Drain Pump Seal Replacement Holyrood Unit 1	16.9	The Unit 1 low pressure drain pump tripped off during operation and subsequent investigation determined that the mechanical seal had failed.	The mechanical seal for the Unit 1 low pressure drain pump and associated cooling water piping were replaced.
Sootblower Carriage Assembly Replacement Holyrood Unit 3	14.6	A Unit 3 boiler sootblower failed to operate when a sootblowing cycle was initiated at the control room. During the Unit 3 annual outage, the issue was investigated and a failed carriage assembly was discovered. The carriage assembly required replacement due to damage to the internal gears.	The failed sootblower carriage assembly for Unit 3 was replaced.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Diesel Generator 3 Protection Relay Replacement Holyrood TGS	13.0	In 2020, Diesel Generator 3 failed to synchronize to the electrical system. It was determined that the main multifunction protection relay could not load the protection program and needed to be replaced to restore normal operation.	The failed protection relay for Diesel Generator 3 was replaced.
Spare Forced Draft Fan Bearing Liner Procurement Holyrood TGS	11.8	The forced draft fan bearing liner failed in 2019.	The failed forced draft fan bearing liner was replaced with an available spare in 2019. A new bearing liner was ordered and received in 2020 to replace the spare.
West Boiler Feedwater Pump Safety Valves Replacement Holyrood Unit 3	11.0	The BFPs provide high pressure feedwater to the boiler during operation. There are safety relief valves on the BFP suction and discharge lines which are designed to relieve excess pressure to protect the pump and associated piping from dangerous overpressure conditions. The suction line safety relief valves on the BFPs failed in-service and were relieving pressure from the line while in operation under normal operating conditions. The valves were damaged beyond repair.	The failed Unit 3 West boiler feedwater pump safety valves were replaced.
West Boiler Drum Water Level Gauge Electronic Verification Unit Replacement Holyrood Unit 2	6.6	During the 2020 outage, it was determined that Unit 2 Boiler Drum West side electronic verification unit for the water level gauge system had a failure in one of its power supplies. Replacement parts for the verification unit are no longer available and a complete replacement unit was required.	The electronic verification unit of the Unit 2 West side boiler drum water level gauge system was replaced and a spare unit was purchased.
Condenser Partition Valve Actuator Replacement Holyrood Unit 1	6.3	The condenser partition valve failed to operate when attempting to perform a backwash on Unit 1 toward the end of the 2019/2020 operating season. During the annual unit outage, it was determined that the condenser partition valve was in adequate condition but the valve's motorized actuator had failed, preventing it from opening/closing. The actuator was found to be damage beyond repair.	The condenser partition valve actuator for Unit 1 was replaced.

Tab 3: Hydraulic Generation
In-Service Failures

2022 Capital Budget Application

Hydraulic Generation In-Service Failures (2022)

July 2021

A report to the Board of Commissioners of Public Utilities

Contents

List of Appendices

Hydraulic Generation In-Service Failures (2022)

Category:	Generation – Hydraulic Plant
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in Hydro's annual capital budget application. The identification is done through the preventive maintenance program using various condition-based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into capital budget applications. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or determination of faster than anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, cavitation, existing installation deficiencies, etc.

Within the scope of this project, Hydro is proposing to undertake the immediate capital refurbishment and replacement work[1] required for its hydraulic generating stations and water reservoirs to maintain safe and reliable operation and to ensure the availability of capital spares[2] required to support such work. These activities will be undertaken in accordance with the philosophies outlined in Hydro's "Hydraulic Generation Asset Management Overview."

[1] This work will not include actions that more appropriately can be executed as Unforeseen or Capital Budget Supplemental projects.
[2] Capital spares are major spare parts that meet the definition of capital assets that are kept on hand to be used in the event of an unexpected breakdown or failure of equipment, thereby expediting the return of the equipment to service. Capital spares are important in reducing periods of interruption in the generation and transmission of electricity.

Hydro uses historical data and the judgement of asset management personnel to determine the Hydraulic Generation In-Service Failures project budget.

2.0 Background

The 2020 Hydraulic Generation In-Service Failures project consisted of 14 corrective actions with a total expenditure of $1.3 million. The corrective actions are detailed in Appendix A.

3.0 Justification

Due to the nature of hydraulic equipment and infrastructure, unanticipated failures and deterioration will occur. This project provides an effective and timely means to undertake the immediate capital refurbishment and replacement work required for hydraulic equipment and infrastructure to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work.

Deferral of work that is justified under this project could result in a detrimental impact to customer power supply or an unacceptable risk to worker or public safety.

4.0 Project Description

Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for its hydraulic generating stations and water reservoirs, as needed, to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions; however, throughout 2022, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

Hydro's estimated project cost of the Hydraulic Generation In-Service Failures project for 2022 is presented in Table 1. Hydro has reassessed the Hydraulic Station In-Service Failures project budget for 2022 based on the average of the actual expenditures from 2018,[3] 2019[4] and 2020[5] and decreased the budget from the $1.25 million proposed and approved in the 2021 Capital Budget Application.

[3] Approximately $452,300.
[4] Approximately $1,374,400.
[5] Approximately $1,287,200.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	461.4	0.0	0.0	**461.4**
Labour	426.9	0.0	0.0	**426.9**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	50.0	0.0	0.0	**50.0**
Interest and Escalation	61.7	0.0	0.0	**61.7**
Contingency	0.0	0.0	0.0	**0.0**
Total	**1,000.0**	**0.0**	**0.0**	**1,000.0**

As there are no planned activities for refurbishment or replacement work, no schedule is provided for those activities.

Work executed under this project in 2022 will be reported to the Board in Hydro’s 2022 Capital Expenditures and Carryover Report and also provided in 2023 as part of the 2024 Capital Budget Application.

5.0 Conclusion

The Hydraulic In-Service Failures project allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro’s effort to maintain safe and reliable operations. This project will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support hydraulic operations.

Appendix A

2020 In-Service Failure Activities

Table A-1: 2020 In-Service Failure Activities

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Units 1–6 Spare Generator Thrust and Guide Bearing Assembly Procurement Bay d'Espoir	276.2	Presently there is one spare thrust and guide bearing assembly for Units 1–6, and it has been determined that a second spare assembly is required for risk mitigation. Over the period of 2017–2019, there were bearing failures of the Unit 2 thrust bearing and the Unit 3 thrust and guide bearings, which were discovered during maintenance activities. There is a high probability that similar failures could occur on the other units. If a failed bearing is not severely damaged, it can be refurbished and maintained as a spare. Refurbishment of a bearing can take 18–22 weeks depending on fabricator availability. If a failed bearing is severely damaged, a new bearing would need to be procured to replenish the spare, and fabrication of a new bearing would take 20–25 weeks depending on fabricator availability.	One set of spare thrust and guide bearings that will fit Bay d'Espoir Units 1–6 was procured and delivered to site.
Capital Spares Procurement Granite Canal and Upper Salmon	234.8	An excitation transformer for the unit at Granite Canal and a transformer for the Upper Salmon Intake Structure were determined to be required for the standby pool to allow fast, responsive action to future failures of long-lead time equipment.	An excitation transformer for Granite Canal was ordered and received in 2020. An intake transformer for Upper Salmon was ordered in 2020 and is expected to be received in the first quarter of 2021. For the Upper Salmon transformer, the planned concrete pad and oil containment system was constructed in 2020.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Dam Stabilization Roddickton	220.7	The Roddickton mini hydro plant includes a 75m-long rock and gravel filled timber crib dam complete with a low-flow drain and an 800mm diameter penstock. The timber crib structure deteriorated to a point where the internal timbers rotted and stability was marginal, particularly during ice loading. Short-term solutions were implemented to manage the reservoir inflows. However, these solutions were no longer successful and more recent events and inspections revealed additional rotting and movement of the structure, increasing the probability of dam failure.	Roddickton dam was stabilized in 2020 by placement of armour stone downstream of the dam. To facilitate the work, road refurbishment and the construction of access ramps were required.
Unit 3 Generator Thrust and Guide Bearing Assembly Refurbishment Bay d'Espoir	115.5	Unit 3 experienced abnormal vibration. Inspection revealed that the thrust and guide bearing assembly was worn past the point of operation and could no longer be placed into reliable service.	The failed bearing assembly was removed from service and replaced with the available spare bearing assembly. The failed bearing assembly was rebabbitted and refurbished to serve as a spare.
Unit 7 Turbine Guide Bearing Refurbishment Bay d'Espoir	77.7	The Unit 7 turbine guide bearing failed in service as a result of a bonding failure between the between the bearing casing and the babbit material. This resulted in a loss of clearance in the bearing.	The failed Unit 7 turbine guide bearing was replaced with the available spare. The failed bearing assembly was rebabbitted and refurbished to serve as a spare.
Units 1, 3, 4, 5 and 6 Generator Bearing Cooler Refurbishment Bay d’Espoir	68.1	A unit generator bearing oil cooler set is comprised of 3 stainless steel coil-type coolers that are submersed in a bath of oil. Cold penstock water flows through the coil and enables heat transfer from the oil to the water, thereby reducing the oil temperature and	Generator bearing oil coolers were refurbished on Units 1, 3, 4, 5, and 6. Existing coolers were then cleaned and refurbished and placed in inventory as spares.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
		ensuring the unit does not run at high temperatures and cause equipment damage. Temperature increases in 2020 were noticed to be higher than the historic norm and trending toward the temperature alarm points. An inspection revealed that the generator bearing cooler sets for Units 1, 4, 5 and 6 were fouled by varnish on the external surface of the coils and had organic buildup on the inside surface. This impacted the bearing cooler heat transfer and cooling capacity which required immediate corrective action to avoid a potential generation disruption.	
Unit Breaker Replacement Paradise River	55.2	The unit breaker failed to close resulting in a forced outage on November 18, 2019 rendering the hydro generating plant unavailable for approximately one week. The investigation revealed that the charging motor had failed and a mechanical shaft was bent. The charging motor was replaced; however the bent mechanical shaft could not be fixed and the breaker was placed back into service with the bent shaft. Further inspection during a unit outage revealed that the open and close gear mechanism showed signs of deterioration, with noticeable wear on the gear teeth. Pieces of metal from the gear teeth were discovered in the interior breaker housing; these were removed, but further wear could cause a short circuit, if	A new unit breaker was procured and installed.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
		the metal pieces contaminate the electrical parts of the breaker. The breaker required replacement.	
Units 1–7 Generator Bearing Oil Replacement Bay d'Espoir	53.3	BDE Units 1–7 generator bearing assemblies are submersed in an oil bath during operation. Oil temperatures were noticed to be trending upward toward the temperature alarm points. When operating at higher temperatures, the oil will break down and trigger a rapid buildup of varnish and other forms of fouling that will lead to equipment deterioration and inoperability. The existing oil has a maximum operating temperature of 74°C and is no longer recommended for use in these units. The operating temperatures of the oil were recorded to be approaching the recommended maximum operating temperature.	The generator bearing oil for BDE Units 1–7 was replaced with an oil recommended by the original equipment manufacturer.
Fire Pump Replacement Hinds Lake	41.4	The internal components and casing of Fire Pump No. 2 deteriorated to the point where the pump was no longer viable for continued operation. The pump had been in service since 1980.	A replacement fire pump was procured under the 2019 Hydraulic In-Service Failures project. Installation was completed in 2020.
Fire Panel Replacement Granite Canal	40.2	The existing fire alarm system for the powerhouse has been in operation since 2002. Replacement parts are no longer available and the system has been indicating sensor faults due to failing alarm system components. The panels and field devices require replacement.	Procurement of replacement fire alarm panels and field devices was completed under the 2019 Hydraulic In-Service Failures project. Installation was completed in 2020.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Shaft Seal Replacement Granite Canal	37.9	The unit turbine shaft carbon seal leakage rate was at a point where all three head cover drainage pumps could not stop the water from entering the turbine pit. The unit tripped offline on March 24, 2020 and March 25, 2020 due to the water levels in the turbine pit. Investigation determined that the shaft carbon seal was exhibiting signs of damage, with scoring observed on the sealing faces.	The turbine shaft carbon seal and related components were replaced.
Oil Skimmer Replacement Upper Salmon	30.8	The mop-type sump oil skimmer, which floats on top of the water to collect oil, was past its useful life and causing issues due to entanglement with equipment and piping located in the sump. Replacement parts were no longer available. The oil skimmer is essential to ensure the recovery of any oil lost within the powerhouse and prevent any discharge into the environment.	The existing oil skimmer was replaced with a belt-type oil skimmer.
Powerhouse 1 Overhead Crane Refurbishment Bay d'Espoir	28.4	While using the powerhouse 30 ton overhead crane, the hoist operated in the opposite direction and travelled up instead of down. This caused the wire rope to fail which damaged the sheaves located on the crane. The upper limit switch lever was also bent beyond repair and replacement was required.	Replacement sheaves, wire rope, and a limit switch were installed and a load test was conducted to re-certify the overhead crane.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Sump Oil In Water Detection System Replacement Granite Canal	7.0	The sump oil in water detection system is used to monitor the sump contents and send an alarm if oil is detected, so that the oil can be removed and not released to the environment. The existing sensor failed and a direct replacement is no longer available.	A replacement oil-in-water detection system was procured and will be installed under the 2021 Hydraulic In- Service Failure project.

Tab 4: Boiler Condition Assessment and Miscellaneous Upgrades

2022 Capital Budget Application

Boiler Condition Assessment and Miscellaneous Upgrades – Holyrood

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Boiler Condition Assessment and Miscellaneous Upgrades – Holyrood

Category: Generation – Thermal Plant

Definition: Clustered

Classification: Normal

Investment Classification: Renewal

Executive Summary

The Holyrood Thermal Generating Station ("Holyrood TGS") is currently a critical part of the Island Interconnected System and is required to provide safe and reliable electricity. Newfoundland and Labrador Hydro ("Hydro") has committed to having the Holyrood TGS fully available for generation until March 31, 2023 to ensure reliable service for customers while the Muskrat Falls Project Assets are brought online and proven reliable. Capital investment related to the generation function of the plant, such as the boiler condition assessment and related upgrades, is necessary to support system reliability.

A Level 2 condition assessment on the internal components of the boilers and associated external high energy piping will be performed to determine whether refurbishment or replacements are required prior to the 2022–2023 winter operating season. Additionally, Hydro will complete upgrades identified in the 2021 condition assessment, as well as those identified during the 2022 assessment work which are necessary to support safe and reliable operation through the 2022–2023 winter operating season.

The boilers and associated high-energy piping are exposed to multiple aggressive degradation mechanisms and require regular inspection and analysis to monitor deterioration rates and plan interventions. Failure while in service could result in generation outages with a duration of weeks or months, depending on the magnitude of the failure. The continuation of the Boiler Condition Assessment and Miscellaneous Upgrades project into 2022 is required to support Hydro's safety and reliability standards, including Hydro's ability to meet customer demand during peak periods. Deferral of this project is not a viable option.

This program has historically been effective for Hydro and supports the optimal timing of refurbishment and replacement. The project is a single-year project which will be completed in 2022, primarily during the planned outages for each generating unit. The budget estimate for this project is $3,014,200.

Contents

1.0 Introduction

For the past five years, Hydro has undertaken a Boiler Condition Assessment and Miscellaneous Upgrades project for the Holyrood TGS. The scope for the project has included a Level 2 condition assessment related to internal components of the main steam generators (boilers) and associated external high energy piping. Throughout the duration of the Boiler Condition Assessment and Miscellaneous Upgrades project, Hydro has proposed and executed various upgrades and replacements to support the reliable operation of the steam generation equipment.

Subsequent to filing its 2021 Capital Budget Application, Hydro announced the extension of Holyrood TGS as a generating facility from March 31, 2022 to March 31, 2023. To support the continued safe and reliable operation of the Holyrood TGS at its rated output through the 2022–2023 winter operating season, Hydro is proposing to continue this program in 2022.

2.0 Background

2.1 Existing System

Holyrood TGS is equipped with three horizontal steam turbine generating units. All three units can be used for power generation, and Unit 3 is also capable of functioning as a synchronous condenser to assist with system voltage regulation. Each unit is supplied with steam by one of three boilers, each of which is dedicated to a generating unit and fired with bunker C fuel.

Boilers 1 and 2 were designed by Combustion Engineering Company and began operating in 1969 and 1970, respectively. Boiler 3 was designed by the Babcock & Wilcox Company and began operating in 1979.

2.2 Operating Experience

The existing main steam generators (boilers) and associated high energy piping (main steam piping, hot reheat piping, cold reheat piping, and high pressure feed water piping) are exposed to high temperatures, high pressure, corrosive fluids, and erosive flows which can cause issues such as thermal cracking, fatigue, corrosion, and erosion. If not identified and corrected pro-actively, these issues can result in sudden and catastrophic failures, with the potential to release hazardous energy and cause significant damage to critical equipment. Regular inspection and analysis of the boilers and high energy piping are required to monitor deterioration rates and plan interventions. Hydro's operating experience has yielded favourable results with annual assessments, as it is not possible to predict the nature of the deterioration until an assessment is undertaken.

The boilers and associated steam supply systems have been the focus of annual Boiler Condition Assessment and Miscellaneous Upgrade projects since 2017. A specialized boiler service contractor has been retained under a maintenance service agreement to perform all remedial work on the boiler including the annual Boiler Condition Assessment and Miscellaneous Upgrades projects. Deficiencies discovered in past condition assessments have included:

- Thinning of the boiler tube walls;
- Cracking of various components that are subject to thermal cycling;
- Critical damage to material or failure of structural components;
- Critical damage to refractory materials;
- Duct erosion; and
- Soot blockages.

Deficiencies identified during inspections are typically corrected during the next available outage period unless they are determined to be critical, in which case they are addressed immediately.

Currently, the 2021 Boiler Condition Assessment and Miscellaneous Upgrades project is underway, with Unit 3 activities and a portion of Unit 1 activities completed in accordance with the 2021 outage schedule. Through planned assessment based on previous findings, examples of many of the above listed deficiency types have been identified and corrected, contributing to the safe and reliable operation of these boilers for the coming winter season. Some of these are listed below.

- Boiler tube wall thinning – a section of reheater tubing in the Unit 3 boiler was found to have thinned below the recommended minimum for reliable operation. Refurbishment has been completed.
- Cracking was found on the steam drum internal surfaces and on the superheater outlet header tube attachment welds of Unit 1. These were corrected.

- Flow accelerated corrosion ("FAC") of a section of eight inch diameter feedwater piping in Unit 3 was detected that had degraded the pipe to the point where replacement of one elbow section was required. This replacement has been completed (see Figures 1 and 2 below).

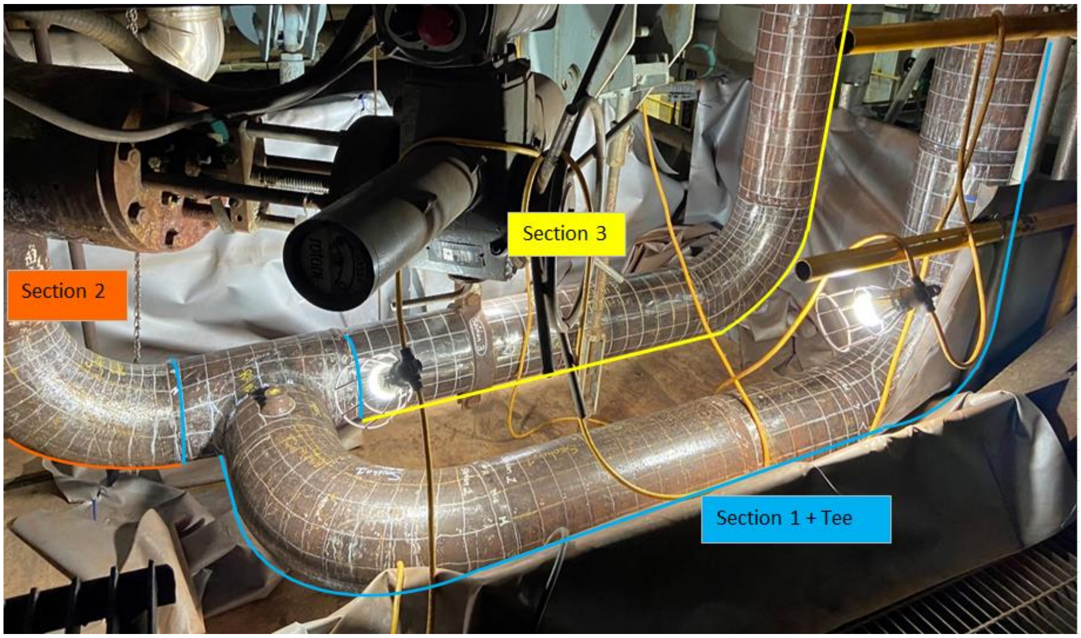

Figure 1: Unit 3 Feedwater Piping Prepared for FAC Assessment.
Assessment determined that the horizontal elbow in the foreground required replacement.

Figure 2: Unit 3 Feedwater Piping Replacement in Progress

3.0 Justification

This project is required to support the reliable operation of Holyrood TGS through March 31, 2023. The condition assessment provides Hydro with the necessary insight into what components of the boilers and associated external high energy piping may require repair or replacement prior to the winter operating season, which permits for work which is either immediately required or will be required in the near-term to be completed in a planned and controlled manner.[1]

Execution of the project will ensure that the condition assessment activities planned for 2022, which are based on assessments during previous editions of this project including 2021 and findings during 2022 execution, are completed as scheduled and recommended.

The consequence of not performing this work is an increased likelihood of forced de-ratings or forced outages ranging from a few weeks to a few months duration, depending on the nature of the failure. A simple failure could result in a two week or longer forced outage due to the need to cool the boiler, remove insulation, provide safe work permits, and erect scaffold. A more significant failure could make a unit unavailable for a period of a couple of months or even for the entire winter operating season.

Because of the extreme operating conditions (high temperature, high pressure, highly erosive and corrosive fluids), deterioration of some components can happen quickly and lead to sudden catastrophic failures with the potential to release hazardous energy and damage critical equipment. Through planned condition assessment and immediate intervention if required, this project will contribute to the safe and reliable operation of all three boilers and related equipment for the following winter season and beyond if required.

[1] The scope of the boiler condition assessment differs from the assessment to determine the potential longer-term viability of the Holyrood TGS, which is being undertaken as part of the Reliability and Resource Adequacy proceeding for the purpose of informing Hydro’s consideration of the role of the Holyrood TGS post-commissioning of the Muskrat Falls Project assets.

4.0 Analysis

4.1 Identification of Alternatives

Hydro considered the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Continuation of the Boiler Condition Assessment and Miscellaneous Upgrades project.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Given Hydro's commitment to have the Holyrood TGS fully available for generation until March 31, 2023, deferral of this project is not viable. Under conditions of normal operation, the deferral of this project increases the risk of failure while in-service, which could result in unit outages during Hydro's 2022–2023 winter operating season. Should such a failure occur during in-service operation, extensive downtime would be required to access internal boiler system components and undertake scaffolding and disassembly work.

This alternative is not viable as it presents an unacceptable risk to Hydro's ability to safely and reliably meet customer needs during peak periods.

4.2.2 Alternative 2: Continuation of the Boiler Condition Assessment and Miscellaneous Upgrades Project

Under this alternative, the condition of internal components of the boilers and associated external high energy piping are assessed through inspections. High-risk issues are corrected immediately upon identification. Annual inspection and assessment of the condition of boiler system components enables early identification of deteriorated components that may fail in the near term, allowing for planned intervention. Components showing moderate deterioration are monitored annually and deterioration rates are trended, allowing for longer-term planning of interventions where appropriate. Hydro has found this approach to be effective in supporting the safe and reliable operation of the Holyrood TGS boilers.

4.3 Proposed Alternative

Hydro proposes the extension of the Boiler Condition Assessment and Miscellaneous Upgrades project for 2022. Regular inspections and condition assessments are required to monitor deterioration rates of systems and perform remedial work an annual basis to reduce risk of failures during operation. This approach allows Hydro to complete repairs in a planned, measured manner while continuing to safely and reliably operate the Holyrood TGS boilers. Hydro's experience with this approach has proven effective; therefore, Hydro proposes to continue the Boiler Condition Assessment and Miscellaneous Upgrades project in 2022.

5.0 Project Description

The primary scope of work is to perform a Level 2 condition assessment on the internal components of the boilers and associated external high energy piping to determine what, if any, refurbishment or replacements are required prior to the 2022–2023 winter operating season. The project also includes completion of miscellaneous upgrades identified in the 2021 investigation and completion of the required interventions identified during the 2022 assessment work that are necessary to support safe and reliable operation through the 2022–2023 winter.

Miscellaneous upgrades will include the replacement of boiler expansion joints and boiler refractory, which were identified in the 2021 condition assessment as requiring replacement. For upgrades identified during the 2022 assessment work and which meet capitalization criteria, as per past practice, Hydro proposes to communicate these items to the Board of Commissioners of Public Utilities in its 2022 Capital Expenditures and Carryover report.

Hydro will contract a specialized boiler service company to complete boiler and high-energy piping assessments and refurbishment. As in previous years, recommendations from this assessment will be documented in a final report from the boiler service company and will feed any future boiler condition assessment work if required. Hydro personnel will assist the service company when required, oversee the work protection application, and provide overall management of the project.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	100.0	0.0	0.0	**100.0**
Labour	397.1	0.0	0.0	**397.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	2,100.0	0.0	0.0	**2,100.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	157.4	0.0	0.0	**157.4**
Contingency	259.7	0.0	0.0	**259.7**
Total	**3,014.2**	**0.0**	**0.0**	**3,014.2**

The assessment and upgrade work will take place during the outage period for each of the three boilers. The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Project planning	January 2022	February 2022
Procurement:		
Purchase long lead parts	March 2022	April 2022
Construction:		
Assessment and upgrades work	April 2022	August 2022
Inspection report	June 2022	November 2022
Close Out:		
Project close out	November 2022	December 2022

6.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS through the 2022–2023 winter operating season, Hydro proposes to continue the Boiler Condition Assessment and Miscellaneous Upgrades project in 2022. This program has historically been effective for Hydro and supports the optimal timing of refurbishment and replacement. This measured, planned approach is prudent and supports the safe and reliable operation of the boilers and high energy piping.

Tab 5: Turbine Valve Overhaul Unit 3

2022 Capital Budget Application

Turbine Valve Overhaul Unit 3 – Holyrood

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Turbine Valve Overhaul Unit 3 – Holyrood

Category:	Generation – Thermal Plant
Definition:	Other
Classification:	Normal
Investment Classification:	Renewal

Executive Summary

The Unit 3 turbine valves at the Holyrood Thermal Generating Station ("Holyrood TGS") are exposed to several degradation mechanisms such as erosion, wear, fatigue and cracking due to high temperature, high pressure, and high flow velocity. Failure of these valves while in operation could result in forced unit outages with duration of several weeks, and could present significant risk to the safety of personnel and other equipment.

The Holyrood TGS is currently a critical part of the Island Interconnected System and is required to provide safe and reliable electricity. Newfoundland and Labrador Hydro ("Hydro") has committed to having the Holyrood TGS fully available for generation until March 31, 2023 to ensure reliable service for customers while the Muskrat Falls Project Assets are brought online and proven reliable. Capital investment related to the generation function of the Holyrood TGS, such as the overhaul of the Unit 3 turbine valves, is necessary to support system reliability.

The valve overhauls are completed on a three-year cycle which has historically yielded acceptable levels of reliability and safety while also being sensitive to the associated cost impacts. The turbine valves were last overhauled in 2019 and, as the unit operated at similar levels as it did in previous overhaul cycles and is expected to be fully available to operate at rated capacity through the 2022–2023 winter, are due for overhaul in 2022.

Hydro evaluated deferral of the project and determined it to result in an unacceptable level of risk to reliability and safety. A condition-based approach to refurbishment is not suitable as the condition of the turbine valves cannot be adequately determined through external inspection or monitoring instrumentation; therefore, disassembly and reassembly of the turbine valves is required.

The cost estimate for this project is $3,623,500. The project is scheduled to be completed prior to the 2022–2023 winter operating season.

Contents

List of Appendices

1.0 Introduction

The Unit 3 turbine is a critical asset required for the generation of 150 MW of power from Unit 3. Proper function of the turbine valves is required for safe and reliable control of the turbine. The turbine is supplied with valves that are critical to operation of the unit. These valves are exposed to several high degradation mechanisms such as erosion, wear, fatigue and cracking due to high temperature, high pressure, and high flow velocity. To support the continued safe and reliable operation of Unit 3 through to March 31, 2023, Hydro is proposing to overhaul Holyrood TGS Unit 3's turbine valves in 2022.

2.0 Background

2.1 Existing System

The Unit 3 turbine was manufactured by Hitachi in 1978. The turbine was supplied with major turbine valves with functions summarized as follows:

- Four control valves for flow regulation, turbine speed control and over-speed protection;
- Two main stop valves and two reheat stop/intercept valves for isolation, shut down, and emergency shut down;
- One blowdown valve for emergency pressure release; and
- Eight extraction steam non-return valves to prevent return of cool water from feed-water preheater and to provide over-speed protection.

2.2 Operating Experience

Hydro performs valve overhauls on a three-year cycle, which, in Hydro's experience, has yielded acceptable levels of reliability and safety. The turbine valves were last overhauled in 2019; Appendix A to this report provides some of the primary findings from the 2019 assessment. Since that time, as the unit operated at similar levels as it did in previous overhaul cycles and is expected to be available to operate at rated capacity through the 2022–2023 winter, the turbine valves are due for overhaul in 2022.

Common sources of turbine valve failure include:

- Oxide scale build-up impeding valve movement and reducing response time;
- Erosion and wear of sealing surfaces impeding control and isolation effectiveness; and

- Cracking and other fatigue compromising pressure-containing components.

3.0 Justification

This overhaul is required to ensure that the turbine valves are in good operating condition, contributing to the continued reliable and safe operation of Unit 3 and the overall reliability of the Island Interconnected System.

Proper operation of all of the turbine valves is required to control the steam flow to the turbine. Any failure will limit production and most likely result in a forced outage. For example, in 2019, a control valve camshaft failure on Unit 2 resulted in a forced outage of 22 days. A similar overhaul is currently ongoing on Unit 1 and the following areas of concern, which could result in downtime ranging from several weeks to several months or contribute to an over-speed event if not proactively addressed, have been identified.

- Two control valves require stem replacement due to excessive run-out (bend) to prevent an in-service failure and forced outage;
- The main stop valve requires stem replacement due to excessive run-out to prevent an in-service failure and forced outage;
- One control valve stem bushing requires replacement due to excessive clearances resulting from wear to prevent an in-service failure and forced outage;
- The steam dam vortex breakers on the main stop valve and the reheat stop valves require refurbishment. Cracks found could result in valve operating problems and parts being liberated into the turbine causing extensive damage and forced outage and potential for over-speed; and
- Several pneumatic actuators on the non-return valves require upgrade to replace springs and pistons that have deteriorated and could impact proper operation of the valve, potentially leading to an over-speed condition or water induction into the turbine.

As these units operate under similar conditions to Unit 3, it would be reasonable to expect the same types of degradation on Unit 3 after similar operating periods. Further, where Unit 3 has operated in similar conditions over this three year period when comparted to the previous three year period, Hydro expects to see similarities in the degradation that was addressed in the 2019 assessment and overhaul. It should be noted, however, that while it can be inferred from historical precedent what issues may arise, it is not possible to predict without disassembling the valves. Hydro has found this interval to be effective in both mitigating reliability concerns and balancing cost impacts.

From a safety perspective, the turbine valves must function properly to prevent over-speed of the turbine and generator rotor during an operational upset condition. The turbine rotor weighs approximately 60,000 pounds and rotates at 60 rotations per second; an over-speed failure has the potential to be catastrophic. Should a unit experience an over-speed event it could run itself to destruction, as well as create unsafe conditions for personnel through fire hazards and the release of turbine blades and other metal objects from the turbine rotor at high speeds. Further, the steam flows to the turbine at very high temperature and pressure. Failure of any turbine valve component has the potential to release energy, which could pose a hazard to personnel.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral of the project;
- Alternative 2: Condition-based refurbishment; and
- Alternative 3: Continued periodic overhaul.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral of the Project

This alternative will result in an increased risk of turbine valve failure. Accepting an increased risk of turbine valve failure while in operation could result in collateral damage and a loss of 150 MW of generation for several weeks which would compromise Hydro's ability to meet customer demand. Delaying valve overhauls will increase the chance of an over-speed event and increase the likelihood of a valve failure. Data obtained through preventive maintenance activities is not comprehensive enough to allow Hydro to make an accurate prediction regarding the likelihood of failure before the next planned overhaul. Therefore, deferral of the overhaul of Unit 3 turbine valves presents an unacceptable risk to safety and reliability.

4.2.2 Alternative 2: Condition-Based Refurbishment

The condition of turbine valves cannot be adequately determined through external inspection or monitoring instrumentation. To assess the condition and determine if, and to what degree, refurbishment is required, the turbine valves must be disassembled and reassembled. As such, condition-based refurbishment of the turbine valves is not a viable alternative.

4.2.3 Alternative 3: Continued Periodic Overhaul

Hydro has historically overhauled the turbine valves every three years, which has yielded acceptable levels of safety and reliability and balanced the cost investment required. This alternative consists of the planned disassembly, detailed internal inspection, and reassembly of all major steam valves. Valves are refurbished through replacement of damaged components identified in the inspections. The last overhaul was successfully completed in 2019. This alternative aligns with past practice and allows Hydro to manage risk within an acceptable level.

4.3 Proposed Alternative

Hydro is proposing to overhaul the Unit 3 turbine valves in 2022. Overhauling the valves will ensure that the valves are in good operating condition, contributing to the continued safe and reliable operation of the Unit 3 turbine through to March 31, 2023. Proper function of the valves is essential for safe and reliable operation of the turbine. Degradation or failure of turbine valves could result in over speed of the turbine leading to a catastrophic failure of the unit. Without regular overhauls, turbine valves are at an elevated risk of malfunction.

5.0 Project Description

The scope of this project consists of a total disassembly, detailed internal inspection, and reassembly of all turbine valves. Valves will be refurbished through replacement of damaged components identified in the inspections.

The overhaul will be performed by an experienced turbine valve overhaul contractor. Plant personnel will assist when required, oversee the work protection application, and provide overall management and liaison for the overhaul work.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	156.0	0.0	0.0	**156.0**
Labour	275.0	0.0	0.0	**275.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	2,700.0	0.0	0.0	**2,700.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	179.3	0.0	0.0	**179.3**
Contingency	313.2	0.0	0.0	**313.2**
Total	**3,623.5**	**0.0**	**0.0**	**3,623.5**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Preparation of scope statement and work breakdown structure	January 2022	March 2022
Construction: Mobilize contractors and perform pre-shutdown checks and isolations	April 2022	May 2022
Construction: Remove, dismantle, and inspect generator	May 2022	June 2022
Construction: Complete repairs and adjustments	June 2022	August 2022
Construction: Re-assemble, perform operational checks, remove isolations, and demobilize contractors	August 2022	September 2022
Close Out: Prepare close out documentation	October 2022	December 2022

6.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS Unit 3 at its rated output of 150 MW through to March 31, 2023, Hydro proposes the overhaul of the Unit 3 turbine valves in 2022. This planned overhaul is consistent with the established three-year turbine valve overhaul frequency that has historically yielded acceptable levels of safety and reliability.

Appendix A

2019 Valve Assessment Primary Findings

In 2019, a valve assessment and subsequent overhaul was completed on Unit 3 with the following primary items identified:

- All valve seats were tested to ensure contact. Lapping was performed on all seats to remove any scale or rough surfaces until acceptable contact test results were achieved. This ensured that all valves would seal completely when closed to prevent an over-speed event;
- Three non-return valves had cracks found in the sealing face of the valve disc (See Figure A-1 and Figure A-2). The discs were refurbished to prevent in-service failure, which could lead to an over-speed event or send foreign material or water into the turbine;
- A cracked valve seat was discovered on Control Valve #2 (See Figure A-3 and Figure A-4). The seat was replaced to ensure proper sealing of the valve for over-speed protection, prevent an in-service failure and forced outage, and prevent foreign material (valve seat material) from entering the turbine;
- A cracked valve seat was discovered on the blowdown valve. The seat was replaced to ensure proper operation of the valve to prevent an over-speed event;
- A crack was found on the left hand side combined reheat valve inlet screen (See Figure A-5). This was repaired to prevent further cracking of the screen and to ensure proper operation of the screen to keep foreign material out of the turbine;
- Excessive run-out (bend) of the stop valve stems was discovered. The stems were replaced to ensure proper operation without binding or excessive wear of components and prevent an in-service failure and forced outage; and
- Several bearings on the control valve camshafts were found with excessive wear or seized. These were replaced to ensure proper operation of the control valves and prevent in-service failure and forced outage.

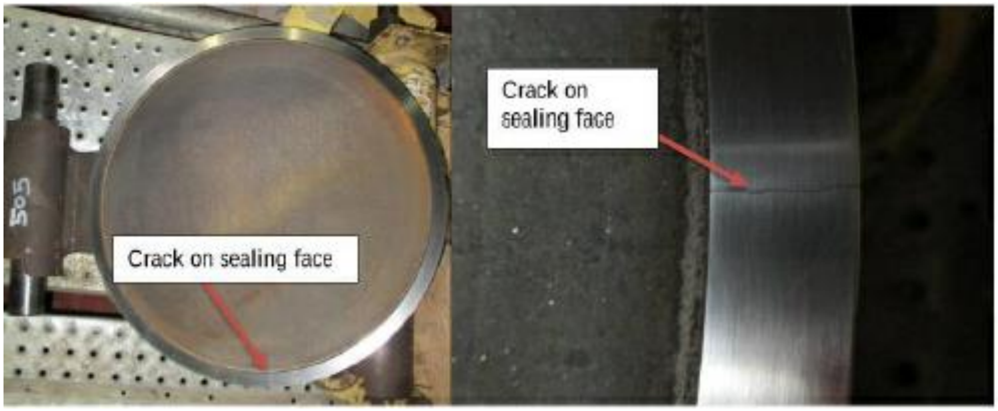

Figure A-1: Crack Found on Sealing Surface of a Non-Return Valve Disc

Figure A-2: Off-Site Refurbishment of Non-Return Valve Discs

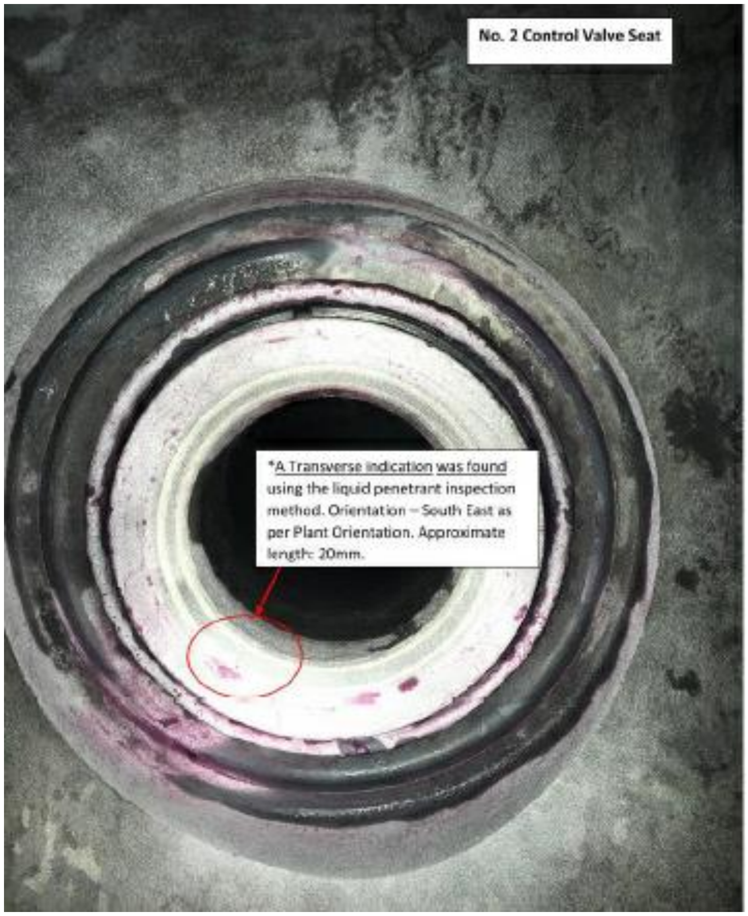

Figure A-3: Crack Found in Control Valve Seat

Figure A-4: Failed Control Valve Seat Removed for Replacement

Figure A-5: Reheat Valve Inlet Screen

Tab 6: Replace Underground Fire Water Distribution System

2022 Capital Budget Application

Replace Underground Fire Water Distribution System Holyrood

July 2021

A report to the Board of Commissioners of Public Utilities

Replace Underground Fire Water Distribution System – Holyrood

Category: Generation – Thermal Plant

Definition: Other

Classification: Normal

Investment Classification: General Plant

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") is proposing to replace the underground fire water distribution system that was originally installed with the construction of the Holyrood Thermal Generating Station ("Holyrood TGS") in 1969 and 1979. In recent years, the existing fire suppression system has experienced a series of failures requiring repair; however, repair has not restored the system to an acceptable condition. Its deteriorated condition and the frequency of failures indicate that the existing underground fire water distribution system has reached the end of its useful life.

Hydro has committed to having the Holyrood TGS fully available for generation until March 31, 2023, after which it is anticipated that the Holyrood TGS will operate as a synchronous condensing station. The underground fire water distribution system is required to provide fire protection for the buildings and assets at the Holyrood TGS as it continues to operate as a synchronous condensing station. Based on the underground fire water distribution system's age, current condition, and the continued requirement for a reliable fire suppression system, Hydro does not believe deferral of this project is appropriate.

The project estimate is $1,706,300. The project is scheduled for completion in 2023.

Contents

1.0 Introduction

The project proposes the replacement of the underground fire water distribution system that was originally installed with the construction of the Holyrood TGS in 1969 and 1979.

Hydro has committed to having the Holyrood TGS fully available for generation until March 31, 2023. It is anticipated that the Holyrood TGS will continue to operate after March 31, 2023 as a synchronous condensing station. The underground fire water distribution system will be required to provide fire protection for the buildings and assets at the Holyrood TGS as it continues to operate as a synchronous condensing station.

2.0 Background

2.1 Existing System

Fire water at the Holyrood TGS is supplied using two fire pumps in the Stage 1 pumphouse. The underground piping system feeds fire water to all the hydrants on site and provides connections for fire pumper trucks. The underground fire water distribution system is composed of 10” asbestos cement piping, cast iron valves and hydrants. It was originally installed during the construction of generating Units 1 and 2 in 1969 and the construction of the generating Unit 3 in 1979. This original system protects the buildings, terminal station and tank farm. An extension to the system was installed with the construction of the gas turbine in 2015.

2.2 Operating Experience

The asbestos cement piping has an expected life span of 50 to 70 years, depending on factors such as the soils surrounding the pipes, water composition, and operating conditions (e.g., pressure and temperature). The asbestos cement pipe material undergoes gradual degradation in the form of corrosion and erosion resulting in pipe thinning, which makes failures more likely to occur.

Currently, the original underground fire water distribution system that was installed in 1969 and 1979 is in a deteriorated condition. Table 1 shows the corrective maintenance history of the underground fire water distribution system at the Holyrood TGS since 2018.

Table 1: Corrective Maintenance History of Underground Fire Water Distribution System Since 2018

Year	Work
2018	Replacement of a Piping Section
2019	Replacement of a Valve
2019	Replacement of a Valve and Hydrant
2019	Replacement of a Piping Section
2020	Replacement of Two Valves
2020	Replacement of Two Hydrants
2021	Replacement of Two Hydrants

The frequency of component failures requiring replacement indicates that the original underground fire water piping has approached its end of useful life. The process of ongoing replacement of components or sections of the piping upon failure has not restored the system to an acceptable condition for long-term operation.

Figure 1 shows a fire distribution line break identified in 2019, located behind the stack of Unit 2. A clamp was temporarily placed on the pipe to stop the water leakage until a replacement section of pipe was installed.

Figure 1: Fire Distribution Line Break behind the Stack of Unit 2

Figure 2 shows water leakage due to a fire distribution line break in 2019 near the terminal station. The leakage presented a hazard as it could extend to the terminal station. A section of pipe was replaced. A valve downstream of this break also required replacement as it failed to isolate the line to complete the pipe section replacement.

Figure 2: Fire Distribution Line Leakage near the Terminal Station.

3.0 Justification

The original underground fire water distribution system has approached the end of its useful life and replacement of this system is required to ensure the continued protection of Holyrood TGS personnel as well as the buildings and assets under fire conditions. This system will continue to be required as the

Holyrood TGS operates as a synchronous condensing station. The process of replacing components or sections of the piping upon failure has not restored the system to an acceptable condition. Due to the criticality of a reliable fire suppression system at the Holyrood TGS facility, replacement is required.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral; and
- Alternative 2: Replacement of underground fire distribution system.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

This alternative requires the continued replacement of components and sections of piping upon failure. The process of replacing failed components or sections of piping has not restored the system to an acceptable condition for long-term operation. Considering the age and deteriorated condition of the original underground fire water distribution system and its continued requirement once the Holyrood TGS transitions to a synchronous condensing station, deferral of this project is not an acceptable option at this time.

4.2.2 Alternative 2: Replacement of Underground Fire Distribution System

This alternative involves replacement of the original underground fire water piping system around the buildings and terminal station to ensure the facility has a reliable fire protection system.

4.3 Proposed Alternative

Hydro is proposing the replacement of the original underground fire distribution system that was installed with the construction of the Holyrood TGS in 1969 and 1979 due to its age and current deteriorated condition.

5.0 Project Description

The project scope of work includes the replacement of the underground fire water distribution system that protects the buildings and terminal station at the Holyrood TGS. The original underground fire water piping that will be replaced is 10” in diameter and approximately 900 m in length.

The original underground piping ring that was installed in 1969 to protect the tank farm is not proposed for replacement at this time as this piping is currently not expected to be required after March 31, 2023.[1]

Figure 3 shows the underground fire water distribution system layout at the Holyrood TGS and highlights the piping including valves and hydrants proposed for replacement in the scope of this project.

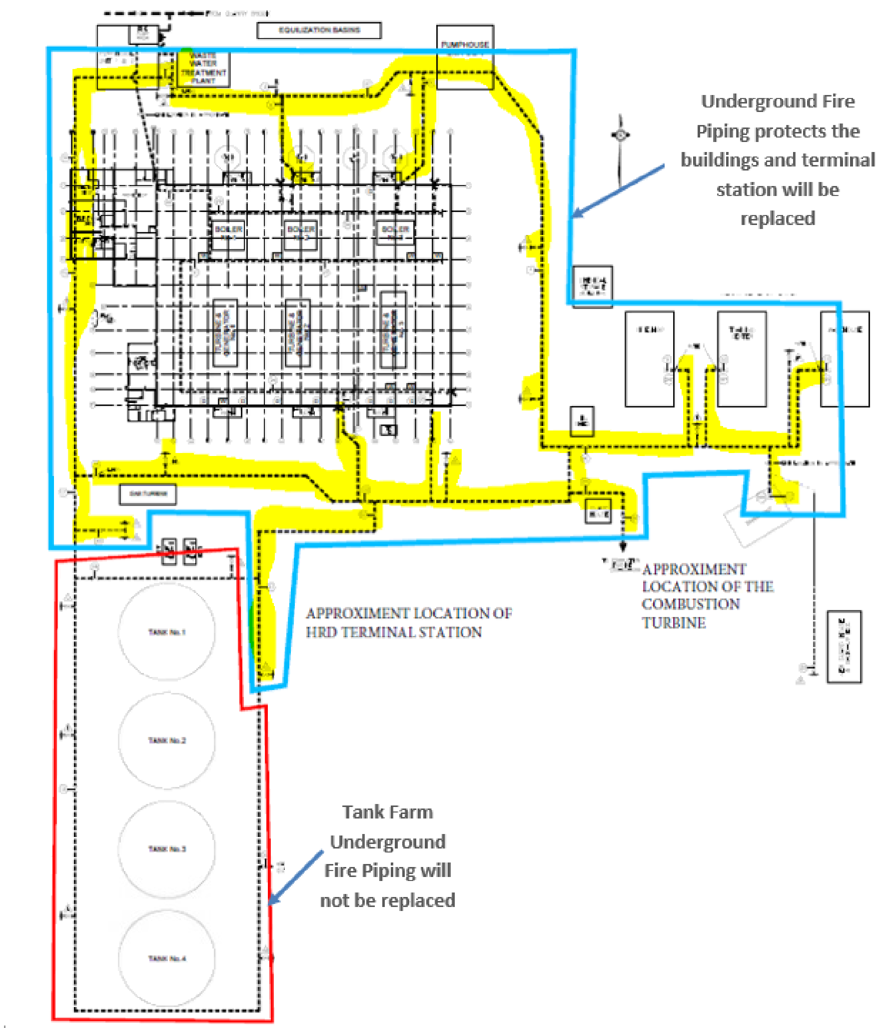

Figure 3: Underground Fire Water Distribution System Layout at the Holyrood TGS.

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[1] Hydro is currently undertaking an assessment to determine the longer term viability of the Holyrood TGS. Should the outcome of that assessment result in extension of the Holyrood TGS beyond the current March 31, 2023 retirement period, Hydro will evaluate whether replacement of the piping surrounding the tank farm will be required. If it is determined to be required, Hydro will request approval of the Board of Commissioners of Public Utilities in a separate application.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0	2.0	0.0	**2.0**
Labour	38.2	127.3	0.0	**165.5**
Consultant	72.0	18.0	0.0	**90.0**
Contract Work	0	1,185.0	0.0	**1185.0**
Other Direct Costs	0	0	0.0	**0**
Interest and Escalation	7.1	112.5	0.0	**119.6**
Contingency	11.0	133.2	0.0	**144.2**
Total	**128.3**	**1,578.0**	**0.0**	**1,706.3**

The conceptual design and technical specification will be completed in 2022. The detailed design, procurement and construction will be completed in 2023 by an external contractor with support from Hydro's engineering and internal labour.

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare planning documentation	January 2022	February 2022
Design:		
Prepare conceptual design and technical specification	May 2022	July 2022
Procurement:		
Award contract for conceptual design and technical conditions	March 2022	April 2022
Award contract for replacement of underground fire water distribution system	March 2023	May 2023
Construction:		
Replace underground fire distribution system	June 2023	September 2023
Close Out:		
Prepare close out documentation	October 2023	December 2023

6.0 Conclusion

This project will replace the original underground fire water distribution system that was installed with the construction of the Holyrood TGS in 1969 and 1979. The system has recently experienced several failures indicating that it has reached the end of its useful life and replacement is required to ensure the long-term safe and reliable operation of the fire water distribution system.

The project will ensure that the fire water distribution system is in a good condition. This system will continue to provide fire protection to the buildings and assets at the Holyrood TGS as it continues to operate as a synchronous condensing station.

Tab 7: Replace Light- and Heavy-Duty Vehicles

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DAVE ROYLE
SIGNATURE
7/25/21
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Replace Light- and Heavy-Duty Vehicles (2022–2024)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Replace Light- and Heavy-Duty Vehicles (2022–2024)

Category:	General Properties – Transportation
Definition:	Pooled
Classification:	Normal
Investment Classification:	General Plant

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) operates a fleet of light-duty vehicles (cars, pickup trucks, and vans) and heavy-duty trucks (aerial devices, material handlers, and boom trucks). The fleet is distributed across Hydro’s operating areas throughout the province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

As part of its review of its capital proposals, Hydro identified light-duty fleet vehicles as an area of opportunity for potential savings in its 2022 Capital Budget Application (“CBA”). Hydro is materially reducing its proposed light-duty vehicle purchases in the 2022 CBA as compared to prior years (i.e., 4 light duty vehicles proposed in 2022 project as compared to historical annual average of 30 light-duty vehicles) and intends to undertake a review of its light-duty vehicle fleet to determine whether its current practices optimize the value of its fleet. Hydro acknowledges that this reduced level of investment in the light-duty fleet likely cannot be sustained in the long term and will use the results of its review to develop future proposals which will reflect a level of investment that appropriately balances fleet safety and reliability with cost. Hydro does not believe that this temporary deviation from its typical replacement schedule will negatively impact reliability as the vehicles which are being deferred can be rented in the short term, if required.

Eight heavy duty vehicles are also planned for replacement under this proposal. Deferral of these vehicles is not appropriate due to the long lead time required to source this equipment, the specific purposes for which it is required, and the limited options for backup should one of the existing heavy-duty vehicles fail.

Hydro’s project reflects a three-year time frame as compared to the two-year projects typically proposed in the past. This change in duration is to reflect vehicle supply chain issues currently being experienced globally and the resultant long lead time for procurement of vehicles.

This project is required for the reliable operation of Hydro's light- and heavy-duty vehicle fleet and is estimated to cost approximately $3,481,800, with scheduled completion in 2024.

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List of Appendices

1.0 Introduction

Hydro operates a fleet of vehicles comprised of light-duty vehicles (cars, pickup trucks, and vans) and heavy-duty trucks (aerial devices, material handlers, and boom trucks). The fleet is distributed across Hydro's operating areas throughout the province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

2.0 Background

Hydro's replacement criteria for light- and heavy-duty vehicles were updated in 2020 and are provided in Table 1.

Table 1: Replacement Criteria - Hydro[1]

Vehicle	Replacement Criteria
Light Duty	7 years or > 200,000 km and Condition/Maintenance Cost
Heavy Duty:	
Classes 4, 5, and 6	6–8 years or > 200,000 km and Condition/Maintenance Cost
Class 7 and 8	7–9 years or > 200,000 km and Condition/Maintenance Cost

Hydro is proposing to temporarily deviate from the above-noted criteria by replacing fewer light-duty vehicles in 2022 while it undertakes a review of its light-duty vehicle fleet to determine whether its current practices optimize the value of its fleet. Hydro does not believe that this temporary deviation from its typical replacement schedule will negatively impact reliability as the vehicles which are being deferred can be rented in the short term, if required.

2.1 Existing System

Please refer to Appendix A for a listing of equipment planned for replacement under this proposal. The listing includes age at retirement, projected kilometres at retirement, and maintenance costs of the vehicles being replaced. Hydro is proposing to replace four light-duty vehicles and eight heavy-duty vehicles in 2022.

[1] Hydro's criteria considers the operating regime for the vehicles and the average replacement criteria used by other Canadian utilities.

2.2 Operating Experience

Table 2 provides the five-year purchase history for vehicle and aerial devices and the budgets for 2020 and 2021.

Table 2: Light- and Heavy-Duty Vehicles Purchases (2017–2022)

Year	Units Purchased		Budget ($000)	Actuals[2] ($000)
	Light-Duty Vehicles	Heavy-Duty Vehicles		
2021–2022	26	6	2,656.0	-
2020–2021	29	10	3,209.0	-
2019–2020	27	5	1,843.0	1,926.5
2018	36	10	2,420.9	2,044.3
2017	36	10	2,400.2	2,173.4

3.0 Justification

The vehicle replacements proposed under this project are required for the reliable operation of Hydro’s light- and heavy-duty vehicle fleet. The four light-duty vehicles which are proposed for replacement are in a condition that necessitates replacement and, in some instances, have specific features which cannot easily be sourced through rental options (e.g., outfitting with equipment required for protection and control work). The vehicles which have been identified for deferral do not have such features; therefore, if required, Hydro could rent the vehicles in the short-term. The heavy-duty vehicles identified for replacement are required due to the long lead-time required to source this equipment, the specific purposes for which it is required, and the limited options for backup should one of the existing heavy-duty vehicles fail.

Hydro’s fleet is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system. Reliable transportation and equipment is necessary for efficient deployment of resources and the safe and timely response to events, potentially impacting the supply of power to customers.

[2] Actual expenditures related to the 2020–2021 and 2021–2022 projects are not known at this time as the projects are ongoing.

4.0 Analysis

4.1 Identification of Alternatives

- Alternative 1: Replace vehicles as per the established criteria; and
- Alternative 2: Defer replacements.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Replace Vehicles as per Established Criteria

Under this alternative Hydro would replace all light- and heavy-duty vehicles that meet the criteria shown in Table 1.

4.2.2 Alternative 2: Defer Replacements

Hydro considered deferring replacement of its light- and heavy-duty vehicles which have met the replacement criteria identified in Table 1. Hydro has determined that temporary deferral of a portion of its light-duty vehicle replacements is a viable option at this time. Heavy-duty equipment has a long lead time for procurement and is required for specific purposes which limit the short-term alternate backup options in the event of failure of existing heavy-duty vehicles. As such, deferring replacement of heavy-duty vehicles is not a viable alternative at this time.

4.3 Proposed Alternative

Hydro is proposing to defer a material portion of light-duty vehicle replacements and replace four light-duty vehicles and eight heavy-duty vehicles. The remaining light-duty vehicles which meet the replacement criteria will be evaluated as part of Hydro's review of its light-duty vehicle fleet management strategy.

5.0 Project Description

This project is for the replacement of four light-duty vehicles and eight heavy-duty vehicles. The purchase of light-duty vehicles includes two fully electric vehicles. The project estimate is provided in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	478.0	477.0	1,943.0	**2,898.0**
Labour	29.5	29.5	33.3	**92.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	7.5	1.1	0.4	**9.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	28.2	60.2	244.1	**332.5**
Contingency	25.8	25.4	98.8	**150.0**
Total	**569.0**	**593.2**	**2,319.6**	**3,481.8**

This is a three-year project due to anticipated COVID-19-related delays in delivery times. The majority of the larger vehicles that are requisitioned in the first year will not be delivered until the third year of the project. The replacement of all proposed vehicles is scheduled to be complete prior to the end of 2024.

6.0 Conclusion

Hydro has chosen to defer replacement of a portion of its light-duty vehicles at this time pending the outcome of a review of its light-duty fleet. Hydro acknowledges that this deferral is temporary and cannot be sustained in the long term; however, Hydro does not believe that this temporary deviation from its typical replacement schedule will negatively impact reliability as the vehicles which are being deferred can be rented in the short term, if required. The four light-duty and eight heavy-duty vehicle replacements which are proposed under this project are required for the reliable operation of Hydro's light- and heavy-duty vehicle fleet.

Appendix A

List of Vehicles and Aerial Devices Scheduled for Replacement

Table A-1: Light-Duty Vehicles Scheduled for Replacement

Type	Description	Projected km	2021 Price ($)	Condition	Life-to-Date Maintenance ($)	Age When Replaced (Years)
SUV[3]	V2850 2015 Chevrolet Equinox	205,000	48,000 (electric)	age/km/ maintenance cost	8,753	7
SUV	V2869 2015 Chevrolet Equinox	185,000	48,000 (electric)	Age/ maintenance cost	17,557	7
Pickup Truck	V2843 2014 Chevrolet	210,000	58,000	km	7,276	8
Pickup Truck	V2955 2016 Chevrolet 2500	216,000	58,000	km	7,507	6

Table A-2: Heavy-Duty Vehicles Scheduled for Replacement

Type	Description	Projected km	2021 Price ($)	Condition	Life-to-Date Maintenance (Estimated) ($)	Age When New Unit Arrives (Years)
Boom MHAD[4]	V4533, 12 Intl 7500 (Max-Force)	105,000	380,000	age/engine/rust	56,753	11–12
Boom MHAD	V4534 12 IHC 7500 (Max-Force)	115,000	380,000	age/rust/ maintenance cost	132,210	11–12
KBoom Truck	V4537, 12 Intl 7500 (Max-Force)	238,000	250,000	age/rust/km/ maintenance cost	178,839	11–12
Line Body	V4541, 12 Intl 7500 (Max-Force)	142,000	170,000	age/rust/engine/ maintenance cost	83,959	11
Boom MHAD	V4557, 15 Intl 7500 (Max-Force)	300,000	380,000	km/engine	72,916	8–9
Boom MHAD	V4560, 15 Intl 7500 (Max-Force)	270,000	380,000	km/engine	75,472	8–9
46’ Material Handler	V4547 Freightliner M2 106	300,000	370,000	km/engine	77,348	8–9
46’ Material Handler	V4559 Freightliner M2 106	320,000	370,000	km/engine	108,607	8–9

[3] Sport-utility vehicle (“SUV”).
[4] Material handling aerial device (“MHAD”).

Tab 8: Perform Software Upgrades and Minor Enhancements

2022 Capital Budget Application

Perform Software Upgrades and Minor Enhancements (2022) – Hydro Place

July 2021

A report to the Board of Commissioners of Public Utilities

Perform Software Upgrades and Minor Enhancements (2022) – Hydro Place

Category:	General Properties – Information Systems – Software Applications
Definition:	Pooled
Classification:	Normal
Investment Classification:	General Plant

Executive Summary

This project involves upgrading software applications used by Newfoundland and Labrador Hydro's ("Hydro") Operating Technology ("OT") group to maintain the Supervisory Control and Data Acquisition ("SCADA") system, as well as applications that support Hydro lines of business such as customer service, drafting, and transmission and rural operations. Specifically, in 2022, Hydro proposes to upgrade software versions of products which provide hydrology management, electrical resource planning, lightning predictive analysis, server system monitoring, electrical meter reading, and frequency monitoring services. Additionally, Hydro proposes to include in the scope of this project minor unforeseen enhancements to software applications which may be required during 2022.

The purpose of the upgrades identified in this project is to ensure existing software to support the Energy Management System ("EMS") and specific business needs are updated to the current versions, will be vendor supported, and are secure to support reliable operations. Deferral of software system upgrades and enhancements would impact the efficiency of Hydro's operations. Replacement is not required as the existing software is performing adequately and minor enhancements can be performed to address the issues identified. Therefore, Hydro proposes upgrading and enhancing the identified software systems in 2022 as it is the least-cost alternative to address the required changes.

The estimated cost of the work reflected in this proposal is $621,700. All planned work is scheduled for completion by the end of 2022.

Contents

1.0 Introduction

This project involves upgrading software applications used by Hydro's OT group to maintain the SCADA system, as well as applications that support Hydro lines of business such as customer service, drafting, and transmission and rural operations. This project also provides for minor enhancements to software applications in response to unforeseen requests to address changing business needs.

2.0 Background

Hydro's OT software systems and computer applications range from engineering drafting tools, controls systems, geographic information systems, financial calculators, planning tools, network analysis tools, and customer utility systems. These systems and applications are used by employees on a daily basis to manage the business. The systems and applications are reviewed regularly to effectively plan necessary enhancements.

2.1 Existing Equipment

Hydro uses a number of applications in customer service, operations, and engineering processes across the business. These Hydro-specific Information Technology and OT applications either directly or indirectly support the EMS.

In 2022, enhancements or upgrades to the following systems are planned to be completed as part of this project:

- The operational data store ("ODS") for EMS database technology that is used to store and manage data collected from the SCADA system. A copy of a subset of data from existing data Historian systems will be created in a secure location outside the core EMS to enhance overall EMS security, performance and reliability by eliminating inbound traffic for data queries.
- Hydro's OT server networks will be further separated into Bulk Electric System ("BES") and several non-BES segments and the corresponding software solutions which are considered as non-BES will be migrated to these non-BES networks. The following software will be migrated, which will require resources to update/upgrade the following systems:
  - Meter reading software;
  - Resource planning software;
  - Hydrology management software;

  - Lightning monitoring software;
  - Frequency monitoring software;
  - Remote access software;
  - System/user authentication software;
  - Mobile EMS View: Web application to provide reporting from EMS; and
  - Electronic file transfer ("EFT") application that allows secure internal file transfers into Hydro non-BES network from administrative network.

- A server system-management suite of applications that is used to monitor the hardware health of the BES and non-BES environments including all servers, workstations, and network infrastructure. It is also used for preventative and corrective maintenance for our virtualized environments as well providing an IP[1] address management database. To ensure overall system stability and reliability, additional licenses need to be acquired to accommodate new devices added for monitoring and software upgraded to the latest release level.
- An industrial automation application that is used to provide an HMI[2] for controlling automated networks in various locations, including Holyrood Thermal Generating Station. The versions of the applications need to be upgraded to the latest release levels to ensure reliability and protect against security vulnerabilities.
- The Planned System Equipment Outage System is an in-house built application/database used by many areas of Hydro. The system is used for all planned equipment outages, for both capital projects and operational maintenance. The Hydro communications/email platform that the system uses will be upgraded to an incompatible version and the underlying operating system and database platform is out of date and, as such, this application/database needs to be rewritten for another platform. A redesign would also be required to apply the latest business rules and processes to meet current requirements and access restrictions.

2.2 Operating Experience

Hydro's business systems and processes require regular planned upgrades and enhancements to maintain efficient and reliable operations. In addition to planned upgrades and enhancements of major

[1] Internet Protocol ("IP").
[2] Human-Machine Interface ("HMI").

systems, Hydro reviews minor upgrade and enhancement requests each year and, where justified, completes the requests or plans for future execution.

3.0 Justification

This project supports Hydro's ability to efficiently respond to changing business needs. Software application and functional requirements are diverse and quickly evolve, as do the technology platforms that the software applications use. The purpose of the upgrades identified in this project is to ensure existing software to support the EMS and specific business needs are updated to the current versions, will be vendor supported, and are secure to support reliable operations.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral;
- Alternative 2: Replace the systems; and
- Alternative 3: Upgrade and enhance the systems.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Under this alternative, systems would be operated without any upgrades or enhancements, resulting in the continued execution of some manual operations which would have otherwise been addressed by the proposed upgrades.

Deferral of software system upgrades and enhancements would impact the efficiency of Hydro's operations and have information system reliability and security impacts. As such, Hydro does not consider this alternative to be viable.

4.2.2 Alternative 2: Replace the Systems

Under this alternative, the systems described in Section 2.1 would be replaced with alternative off-the-shelf solutions written by third-party vendors. This would include engaging vendors through the request for proposals process and creating new capital projects to replace them. Replacement is not required, as the existing software is performing adequately and minor enhancements can be performed to address the issues identified. Replacement is also a more expensive alternative to upgrading and enhancing.

4.2.3 Alternative 3: Upgrade and Enhance the Systems

Under this alternative, the previously described software systems would be upgraded and enhanced as required. Requests from local users and operating areas for additional upgrades and enhancements may also be completed under this project in 2022, if they are determined to be justified. This alternative will ensure Hydro's software systems are up to date and fully supported, ensuring reliable and secure operation of Hydro's infrastructure.

4.3 Proposed Alternative

Hydro proposes upgrading and enhancing the identified software systems in 2022. This alternative is the least-cost alternative to address the required changes.

5.0 Project Description

For 2022, this project will upgrade electrical resource planning, lightning predictive analysis, server system monitoring, electrical meter reading and frequency monitoring applications.

Enhancements will be completed to the Planned System Equipment Outage System by improving integration processes, forms functionality, and system reporting capabilities. Enhancements will also be made to the ODS, EFT, and EMS View and device/user authentication systems to improve overall EMS security.

Additionally, unforeseen requests received in 2022 for justifiable upgrades and enhancements will be completed within the approved budget for this project where possible. Such unplanned work will be reported in Hydro's 2022 Capital Expenditures and Carryover Report.[3]

[3] Due to be filed March 1, 2023.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	94.0	0.0	0.0	**94.0**
Labour	253.2	0.0	0.0	**253.2**
Consultant	9.8	0.0	0.0	**9.8**
Contract Work	161.4	0.0	0.0	**161.4**
Other Direct Costs	11.1	0.0	0.0	**11.1**
Interest and Escalation	19.4	0.0	0.0	**19.4**
Contingency	72.8	0.0	0.0	**72.8**
Total	**621.7**	**0.0**	**0.0**	**621.7**

The anticipated project schedule is shown in Table 2.

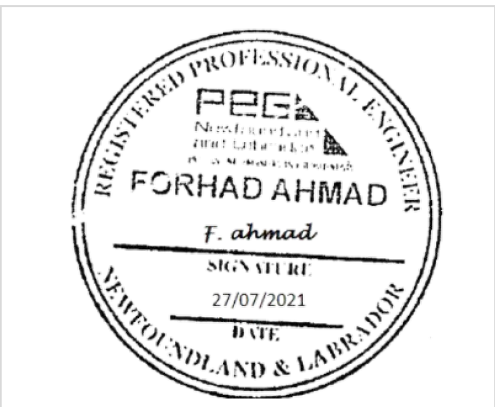
Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Create request for proposals and review schedules	January 2022	March 2022
Design:		
Conduct business requirements, complete detailed design, and create project plan	January 2022	April 2022
Procurement:		
Award request for proposals, secure resources, and order materials	February 2022	May 2022
Construction:		
Build software enhancements and install hardware	May 2022	November 2022
Commissioning:		
Go live with enhancements	September 2022	November 2022
Close Out:		
Close out project	November 2022	December 2022

6.0 Conclusion

Hydro maintains many software systems to support its business processes. Upgrades and enhancements are planned on a regular basis to continually improve software systems and their functionality. For 2022, Hydro has continued to combine its upgrade and enhancement budgets into a single project for improved administration and execution efficiency. This project includes planned upgrades and enhancements and also allows Hydro to respond to additional requests for system improvements that cannot be deferred to a subsequent year.

Tab 9: Purchase 85’ Material Handler Aerial Device on Track Unit



2022 Capital Budget Application

Purchase 85’ Material Handler Aerial Device on Track Unit

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Purchase 85' Material Handler Aerial Device on Track Unit

Category:	Transmission and Rural Operations – Tools and Equipment
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") uses aerial devices wherever possible to efficiently perform maintenance and upgrade work on its distribution and transmission assets. Hydro must have access to functional and reliable equipment to safely and efficiently maintain its system.

To replace equipment which is due for retirement, Hydro plans to purchase new equipment that will increase work efficiency and its application of live line techniques. Since implementing its Live Line Program in 2018, more than 250,000 customer outage hours have been avoided with the use of live line techniques.

This project proposes the purchase of an 85' Category A insulated aerial device on an off-road track unit to access transmission lines and structures in off-road locations. Hydro currently has only one tracked aerial device within the 85' range. This equipment only permits live line work with insulated tools on voltages up to 69 kV. Hydro's transmission line voltages consist of 69 kV, 138 kV, and 230 kV. The unit Hydro is proposing to purchase will facilitate live line work on transmission lines with voltages up to 230 kV.

This project is estimated to cost approximately $1,353,900 and is scheduled for completion in 2024.

Contents

1.0 Introduction

Newfoundland and Labrador Hydro (”Hydro”) uses aerial devices wherever possible to efficiently perform maintenance and upgrade work on its distribution and transmission assets. With some existing off-road equipment due for replacement, Hydro plans to purchase new equipment that will increase work efficiency and its application of live line techniques on transmission lines with voltages up to 230 kV. Since implementing its Live Line Program in 2018, more than 250,000 customer outage hours have been avoided with the use of live line techniques.

2.0 Background

Hydro maintains a fleet of off-road track equipment to perform work in off-road locations; some of this equipment is due to be replaced. With the addition of an 85’ Category A[1] aerial device track unit, Hydro plans to retire two existing units, a 2001 Bombardier crew carrier and a 1999 Bombardier Muskeg equipped with a boom, that have exceeded their service life.

2.1 Existing System

Hydro does not have an off-road track unit with an 85’ Category A insulated boom; Hydro currently has only one tracked aerial device within the 85’ range. The existing unit is a 100’ Category B insulated aerial device on a track unit which only allows live line work with insulated tools on voltages up to 69 kV. Hydro’s transmission line voltages consist of 69 kV, 138 kV, and 230 kV. This existing unit is a 2005 model and is now 16 years old. It is the only insulated unit available within the company to service Hydro’s transmission lines across the province.

2.2 Operating Experience

The existing fleet of equipment used for off-road transmission line work is limited and does not allow Hydro to apply the most efficient work methods. The proposed equipment will further improve the application of Hydro’s Live Line Program on transmission lines in off-road areas and allow Hydro to respond more efficiently to transmission outages and trouble calls.

[1] American National Standards Institute ANSI A92.2 Category A.

3.0 Justification

Performing work with aerial devices is safe and efficient and reduces customer impacts. For work on transmission lines in off-road locations, Hydro currently has only one insulated aerial device to service transmission lines across the province. Hydro is proposing to retire two units that are due for replacement and replace with a single 85' material handler aerial device on a heavy-duty off-road track. This will increase Hydro's ability to complete transmission line work efficiently, reduce response times to issues on the transmission system, and further expand its ability to apply live line techniques.

4.0 Analysis

4.1 Identification of Alternatives

- Alternative 1: Deferral.
- Alternative 2: Purchase 85' material handler aerial device on track unit.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

With the upcoming retirement of equipment used to support off-road transmission line work, Hydro has to plan for replacement. Deferral of the replacement of end-of life equipment is not an acceptable alternative. Additionally, the proposed equipment will result in improved efficiencies for Hydro and reduced response time to issues on the transmission system.

4.2.2 Alternative 2: Purchase 85' Material Handler Aerial Device on Track Unit

Under this alternative, Hydro will retire two units, which are due for retirement, and replace them with an 85' Category A aerial device on track machine with a power line technician bucket, jib, and winch, required for transmission work.

4.3 Proposed Alternative

Hydro is proposing to purchase an 85' material handler aerial device on track unit.

5.0 Project Description

This project proposes the purchase of an 85' Category A insulated aerial device on track unit for work on transmission lines and structures. The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	1,060.0	0.0	**1,060.0**
Labour	18.2	14.9	7.1	**40.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	1.3	83.9	60.3	**145.5**
Contingency	0.9	106.9	0.4	**108.2**
Total	**20.4**	**1,265.7**	**67.8**	**1,353.9**

This is a three-year project due to the anticipated procurement timeline and high demand for this particular vehicle.

The anticipated project schedule for the purchase of 85' material handler aerial device on a heavy-duty off-road track unit is presented Table 2.

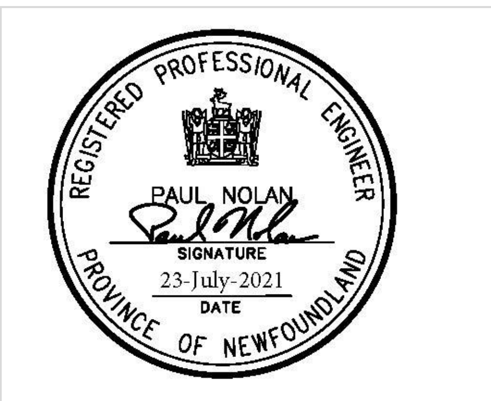
Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	January 2022	February 2022
Technical Specifications:		
Develop technical specifications	March 2022	March 2022
Procurement:		
Tender and award	March 2022	April 2022
Delivery:		
Have new unit delivered to operating group	October 2023	November 2023
Close Out:		
Project completion certificate and lessons learned	January 2024	March 2024

6.0 Conclusion

The purchase of an off-road track unit with an 85' Category A aerial device will replace two existing units and allow Hydro to complete transmission line work more efficiently. This equipment will also allow Hydro to further expand its application of live line techniques and reduce customer impacts.

Tab 10: Terminal Station Refurbishment and Modernization



2022 Capital Budget Application

Terminal Station Refurbishment and Modernization (2022–2023)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Terminal Station Refurbishment and Modernization (2022–2023)

Category: Transmission and Rural Operations – Terminal Stations

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces or refurbishes failing or failed terminal station assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Hydro's philosophy for the assessment of equipment and the selection and justification of projects is outlined in the Terminal Station Asset Management Overview – Version 6 ("Asset Management Overview") included as Attachment 1 to this report.

In the 2022 Capital Budget Application, Hydro proposes the following activities under the Terminal Station Refurbishment and Modernization project:

- Replacement of instrument transformers;
- Replacement of disconnect switches;
- Refurbishment and modernization of power transformers;
- Replacement of terminal station lighting;
- Replacement of battery banks and chargers;
- Refurbishment of equipment foundations;
- Installation of fire suppression systems in control buildings; and
- Protection, control, and monitoring replacements and modernization.

Hydro will execute the majority of these activities in a multi-year approach, with all activities scheduled for completion before the end of 2023.

The total project estimate is $9,221,600.

Contents

List of Attachments

1.0 Terminal Station Refurbishment and Modernization Project

Terminal stations perform a critical role in the transmission and distribution of power across the province. Terminal stations contain electrical equipment including, transformers, circuit breakers, instrument transformers, disconnect switches, and all associated protection and control relays and equipment required to protect, control, and operate the province's electrical grid. Terminal stations act as transition points in the transmission system and interface points with the lower voltage distribution and generation systems. Hydro has 69 terminal stations across the Island and Labrador Interconnected Systems.

Hydro executes a robust capital program to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. Hydro's capital program sees the replacement and refurbishment of equipment based on Hydro's long-term asset management strategy as outlined in the Asset Management Overview.

2.0 Terminal Station Refurbishment and Modernization 2022 Projects

The Asset Management Overview outlines Hydro's asset management programs as they relate to terminal station equipment. The assets designated for replacement, refurbishment, or modernization herein have been selected by Hydro's asset management staff to align with Hydro's commitment to the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. Unless otherwise stated, there are no viable alternatives for the refurbishment or replacement of the equipment designated herein, as continued operation of the assets without refurbishment or replacement would put the reliability of the electrical system, or the safety of the public or those who operate the system, at risk. The philosophy for assessment, selection, and justification of these projects is found in the Asset Management Overview.

2.1 Electrical Equipment

The following electrical equipment upgrades and/or refurbishments are planned for 2022:

- Replace instrument transformers;
- Replace disconnect switches;
- Refurbish and upgrade power transformers;
- Replace station lighting; and
- Replace battery banks and chargers.

2.1.1 Replace Instrument Transformers

The estimate of direct costs for this project is shown in Table 1.

Table 1: Direct Costs Estimate for the Replace Instrument Transformers Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	69.0	65.4	0.0	**134.4**
Labour	27.2	113.2	0.0	**140.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	8.8	0.0	**8.8**
Interest and Escalation	3.8	17.6	0.0	**21.4**
Contingency	9.7	18.8	0.0	**28.5**
Total	**109.7**	**223.8**	**0.0**	**333.5**

Project Scope

Hydro replaces instrument transformers due to physical or electrical deterioration, or to comply with federal regulations regarding the use of polychlorinated biphenyls, as detailed in Section 4.1.1 of the Asset Management Overview. Hydro plans to replace the instrument transformers in Table 2. All of the identified instrument transformers are planned to be replaced before the end of 2023.

Table 2: Instrument Transformer Replacements

Station	Equipment ID	Replacement Criteria
Massey Drive	B2T2 'A' phase CT[1]	Age (55)
Massey Drive	B2T2 'B' phase CT	Age (55)
Massey Drive	B2T2 'C' phase CT[2]	Age (55)
Bay d'Espoir Terminal Station 1	B1 'B' phase CVT[3]	System Concern[4]
Bay d'Espoir Terminal Station 1	B2 'B' phase CVT	System Concern
Bay d'Espoir Terminal Station 1	B3 'B' phase CVT	System Concern
Holyrood	TL268 (242) CØ, CVT	Condition
Wabush Terminal Station	L24 (L2304) AØ, CVT	Condition

2.1.2 Replace Disconnect Switches

The estimate of direct costs for this project is shown in Table 3.

Table 3: Direct Costs Estimate for the Replace Disconnect Switches Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	112.0	61.0	0.0	**173.0**
Labour	99.3	342.0	0.0	**441.3**
Consultant	20.8	20.8	0.0	**41.6**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	6.2	47.6	0.0	**53.8**
Interest and Escalation	11.0	43.2	0.0	**54.2**
Contingency	23.8	47.1	0.0	**70.9**
Total	**273.1**	**561.7**	**0.0**	**834.8**

Project Scope

Hydro replaces disconnect switches when damaged beyond refurbishment, when parts required for refurbishment are unavailable due to obsolescence, when it is not economical to refurbish, or when switches are damaged or defective and have reached a service life of 50 years, as detailed in Section 4.1.2 of the Asset Management Overview. Hydro plans the replacement of the disconnect switches in Table 4. All of the identified disconnect switches are scheduled to be replaced before the end of 2023.

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[1] Current transformer ("CT").
[2] Current transformer no longer required and will be replaced with post insulators.
[3] Capacitor voltage transformer ("CVT").
[4] Bay d'Espoir TS1, B1, B2, and B3 CVTs to be replaced with potential transformers to mitigate transient voltages on unit breakers.

Table 4: Disconnect Switches Replacements

Station	Equipment ID	Replacement Criteria
Bay d'Espoir	B1B10-2	Condition + Age (55)
Indian River	B1L363-1	Condition + Age (53)
Massey Drive	B2GT-1	Condition + Age (54)
South Brook	L22-2/L22G-2	Obsolescence + Age (54)
Stony Brook	B1T1	Obsolescence + Age (51)
Sunnyside	L100L109-2/L109G	Condition + Age (54)
Wabush Terminal Station	B1T5/T5G[5]	Condition + Age (48)
Wabush Terminal Station	CAP-2G	Condition

2.1.3 Refurbish and Upgrade Power Transformers

The estimate of direct costs for this project is shown in Table 5.

Table 5: Direct Costs Estimate for the Refurbish and Upgrade Power Transformers Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	10.0	893.5	0.0	**903.5**
Labour	284.7	660.7	0.0	**945.4**
Consultant	73.6	92.0	0.0	**165.6**
Contract Work	363.0	695.0	0.0	**1,058.0**
Other Direct Costs	29.0	132.9	0.0	**161.9**
Interest and Escalation	32.9	167.0	0.0	**199.9**
Contingency	76.0	247.4	0.0	**323.4**
Total	**869.2**	**2,888.5**	**0.0**	**3,757.7**

Project Scope

Hydro carries out a number of refurbishment and upgrade activities on power transformers, including:

- Oil reclamation or replacement;
- Oil dehydration;
- Corrosion remediation;
- Refurbishment to address leaks;
- Tap changer overhauls;
- Bushing replacements;

[5] Installation and commissioning only.

- Protective device replacements;
- Cooling fan/radiator replacement; and
- Major refurbishment, which may include combinations of the above.

Hydro also installs online dissolved gas analysis ("DGA") devices on critical power transformers. Hydro's power transformer refurbishment and modernization philosophies can be found in Section 4.1.6 of the Asset Management Overview. Hydro plans to complete refurbishments and upgrades on the following power transformers:

2022

- Grand Falls Frequency Converter T2: Oil refurbishment;
- Hinds Lake T1: leak refurbishment and internal inspection; and
- Hinds Lake T2: leak refurbishment.

2023

- Massey Drive GT1 Major Refurbishment: replace bushings (HV[6]) and transformer oil moisture reduction;
- Rocky Harbour T1 Major Refurbishment: replace bushings (HV, LV,[7] and X0[8]), transformer oil moisture reduction and painting;
- Stephenville T3 Major Refurbishment: replace bushings (HV, LV, and N[9]), replace radiators (12), replace gas piping fittings and gas relay fittings, leak refurbishment, install online DGA monitor, and painting;
- Upper Salmon T1 Major Refurbishment: replace bushings (HV and N), oil processing, and leak repair;
- Western Avalon GT1 Major Refurbishment: replace bushings (HV) and transformer oil moisture reduction;

[6] High voltage ("HV").
[7] Low voltage ("LV").
[8] Neutral located on low-voltage winding ("X0").
[9] Neutral ("N").

- Buchans GT1: HV and H0[10] bushing replacement;
- Glenburnie T1: replace bushings (HV, LV, and N);
- Holyrood T3: replace bushings (HV and N);
- Happy Valley T4: install online oil dehydrator and online DGA monitor;
- Oxen Pond T3: refurbish tap changer;
- Happy Valley T2: install online DGA monitor;
- Hardwoods T4: install online DGA monitor; and
- South Brook T1: install online DGA monitor.

2.1.4 Replace Station Lighting

The estimate of direct costs for this project is shown in Table 6.

Table 6: Direct Costs Estimate for the Replace Station Lighting Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	82.0	0.0	**82.0**
Labour	22.1	102.7	0.0	**124.8**
Consultant	9.9	10.9	0.0	**20.8**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.9	0.9	0.0	**1.8**
Interest and Escalation	1.7	13.7	0.0	**15.4**
Contingency	3.3	19.6	0.0	**22.9**
Total	**37.9**	**229.8**	**0.0**	**267.7**

Project Scope

Hydro replaces or adds station lighting due to deteriorated physical condition or inadequacy of existing lighting in order to ensure adequate station lighting during the night for the safety of operations personnel, as detailed in Section 4.1.11 of the Asset Management Overview. Hydro assessed the terminal station lighting in the Buchans and Hardwoods Terminal Stations and identified significant corrosion and moisture ingress issues impacting the function of the lighting systems. Hydro plans to replace the station lighting in the Buchans and Hardwoods Terminal Stations starting in 2022.

[10] Neutral located on high-voltage winding ("H0").

2.1.5 Replace Battery Banks and Chargers

The estimate of direct costs for this project is shown in Table 7.

Table 7: Direct Costs Estimate for the Replace Battery Banks and Chargers Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	22.4	72.0	0.0	**94.4**
Labour	47.3	44.4	0.0	**91.7**
Consultant	57.2	25.0	0.0	**82.2**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	9.1	0.9	0.0	**10.0**
Interest and Escalation	6.3	12.9	0.0	**19.2**
Contingency	13.6	14.2	0.0	**27.8**
Total	**155.9**	**169.4**	**0.0**	**325.3**

Project Scope

The service life of flooded cell batteries and valve-regulated lead-acid batteries is approximately 20 years and 10 years, respectively. Battery chargers have a service life of 20 years. Hydro replaces battery banks and chargers that meet this age criteria. Hydro also replaces battery banks and chargers if testing shows that they are deteriorating or are approaching insufficient capacity, as detailed in Section 4.1.9 of the Asset Management Overview. Hydro plans to replace battery banks in the following locations:

- St. Anthony Diesel Plant Terminal Station (in 2022);
- English Harbor West Terminal Station (in 2022); and
- Hardwoods Terminal Station (in 2023).

Hydro plans to replace battery chargers in the following location:

- South Brook Terminal Station (in 2023).

2.2 Civil Works and Buildings

The following Civil Works and Buildings activities are planned for 2022:

- Refurbish equipment foundations; and
- Install fire suppression.

2.2.1 Refurbish Equipment Foundations

The estimate of direct costs for this project is shown in Table 8.

Table 8: Direct Costs Estimate for the Refurbish Equipment Foundations Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	226.8	0.0	0.0	**226.8**
Consultant	101.7	0.0	0.0	**101.7**
Contract Work	169.7	0.0	0.0	**169.7**
Other Direct Costs	31.4	0.0	0.0	**31.4**
Interest and Escalation	31.9	0.0	0.0	**31.9**
Contingency	53.0	0.0	0.0	**53.0**
Total	**614.5**	**0.0**	**0.0**	**614.5**

Project Scope

Hydro refurbishes concrete foundations in terminal stations when the foundations have deteriorated severely, compromising structural integrity if not addressed, as detailed in Section 4.2.1 of the Asset Management Overview. Based on a condition assessment, Hydro plans to refurbish equipment foundations in the Barachoix and Linton Lake Terminal Stations.

2.2.2 Install Fire Suppression

The estimate of direct costs for this project is shown in Table 9.

Table 9: Direct Costs Estimate for the Install Fire Suppression Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	16.9	60.6	0.0	**77.5**
Consultant	8.0	20.0	0.0	**28.0**
Contract Work	0.0	318.0	0.0	**318.0**
Other Direct Costs	0.0	1.9	0.0	**1.9**
Interest and Escalation	1.7	32.5	0.0	**34.2**
Contingency	2.5	40.1	0.0	**42.6**
Total	**29.1**	**473.1**	**0.0**	**502.2**

Project Scope

Hydro is installing fire suppression systems in all 230 kV terminal station control buildings due to station criticality, as detailed in Section 4.2.2 of the Asset Management Overview. Hydro plans to install a fire suppression system in the Buchans Terminal Station control building in 2022–2023.

2.3 Protection, Control, and Monitoring Refurbishment and Upgrades

The estimate of direct costs for this project is shown in Table 10.

Table 10: Direct Costs Estimate for the Protection, Control, and Monitoring Refurbishment Upgrades Project ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	544.4	8.5	0.0	**552.9**
Labour	326.5	1,142.0	0.0	**1,468.5**
Consultant	32.4	4.9	0.0	**37.3**
Contract Work	0.0	107.9	0.0	**107.9**
Other Direct Costs	12.0	72.9	0.0	**84.9**
Interest and Escalation	46.2	150.7	0.0	**196.9**
Contingency	61.0	76.5	0.0	**137.5**
Total	**1,022.5**	**1,563.4**	**0.0**	**2,585.9**

2.3.1 Project Scope

Hydro has an ongoing program to replace electromechanical and obsolete solid-state relays with modern digital relays, improving reliability and functionality. Hydro's approach to protection, control, and modernization asset management is detailed in Section 4.3 of the Asset Management Overview.

Hydro plans to replace the following protective relays for the following in 2022–2023:

- Transformer T6 (Wabush Terminal Station);
- Line 4 (Wabush Terminal Station);
- Transformers GT1 and T3 (Stephenville Terminal Station);
- Transformer T1 (Stony Brook Terminal Station);
- Transformer T2 (Stony Brook Terminal Station);
- Transformer T3 (Holyrood Terminal Station); and
- Unit G3 (Holyrood Generating Station).

Hydro assesses the condition of legacy breaker failure protection systems in 230 kV stations during regular maintenance procedures. Through these assessments, Hydro has identified the requirement to replace the breaker failure protection in the Deer Lake Terminal Station.

Hydro will also install digital fault recorders in the Wabush Terminal Station to improve the analysis of system events in the area served by the terminal station.

Hydro will also upgrade existing reclosing packages for the Sunnyside B1L03 and Holyrood B1L65 breakers to ensure that single-phase tripping returns the faulted phase to service automatically and does not result in the loss of the line.

Hydro will also refurbish or replace protection and control panels, wiring, cables, or trenches that may require alteration, replacement, or addition to existing wiring due to deterioration from environment conditions, accidental damage, or the modification/addition of protection and control equipment.

3.0 Conclusion

This report provides information and justification related to the projects Hydro is proposing to undertake on its terminal stations under its Terminal Station Refurbishment and Modernization Program in 2022–2023.

The estimate for this project is shown in Table 11.

Table 11: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	757.8	1,182.4	0.0	**1,940.2**
Labour	1,050.8	2,465.6	0.0	**3,516.4**
Consultant	303.6	173.6	0.0	**477.2**
Contract Work	532.7	1,120.9	0.0	**1,653.6**
Other Direct Costs	88.6	265.9	0.0	**354.5**
Interest and Escalation	135.5	437.6	0.0	**573.1**
Contingency	242.9	463.7	0.0	**706.6**
Total	**3,111.9**	**6,109.7**	**0.0**	**9,221.6**

Due to the large number of activities enveloped in this project, it is not practical to provide individual project schedules. Detailed project schedules will be developed at project initiation. A typical high-level schedule for a multi-year project is as follows:

- Year 1: planning, design, and procurement; and
- Year 2: construction, commissioning, and close out.

All activities are scheduled to be completed before the end of 2023.

Attachment 1

Terminal Station Asset Management Overview

Version 6

2022 Capital Budget Application

Terminal Station Asset Management Overview
Version 6

July 2021

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has developed an ongoing capital program to replace or refurbish assets as they reach the end of their design life or require attention due to obsolescence or anticipated failure.

Before 2017, Hydro's terminal station projects could be divided into two categories: (1) stand alone and (2) programs. Programs included projects that are proposed year after year to address the upgrade or replacements of deteriorated equipment, such as disconnects or instrument transformers, and have similar justification each year. Stand alone would include projects that do not meet the definition of a program. Hydro has typically had as many as 15 separate program-type terminal station projects in its capital budget applications, with each program based upon a particular type of asset.

Starting with the 2017 Capital Budget Application ("CBA"),[1] Hydro implemented a change to how the terminal station projects are submitted for consideration by the Board of Commissioners of Public Utilities ("Board"). Hydro has consolidated the programs into the Terminal Station Refurbishment and Modernization project ("Project"), thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro and allowing Hydro to look for opportunities to realize efficiencies by improving coordination of capital and maintenance work in terminal stations.

In 2019, Hydro submitted a revised Terminal Station Asset Management Overview ("Asset Management Overview") to provide an updated overview of Hydro's asset maintenance philosophies in one document. Hydro will submit the Project within annual CBAs going forward, proposing required terminal station work and referencing this Asset Management Overview document.

[1] "2017 Capital Budget Application," Newfoundland and Labrador Hydro, July 28, 2016.

Contents

1.0 Introduction

Hydro has 69 terminal stations that contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical grid.

Hydro's Asset Management System governs the life cycle of its terminal station assets. This system monitors, maintains, refurbishes, replaces, and disposes of assets with the objective of providing safe, reliable electrical power in an environmentally responsible manner at least cost. Within this system, assets are grouped, such as breaker, transformers, grounding systems, buildings, and sites. This allows the asset managers to establish consistent practices for equipment specification, placement, maintenance, refurbishment, replacement, and disposal. These practices mean that the monitoring, assessments, action justifications for capital refurbishment, and replacement for asset-sustaining projects are consistent. Hydro established programs which enact these practices for groups or sub-groupings of assets, for example high-voltage switch replacements.

Part of Hydro's annual capital program is a sustained effort to ensure the safety and reliability of terminal station assets. Historically, the Board's approval for this effort has been requested by Hydro submitting either individual projects for particular assets, or programs for station-sustaining work in its CBA. This approach can result in a segmented view of the expenditures to sustain station assets. For example, in the 2016 CBA, there were 15 separate program-type projects submitted. The expenditures detailed in these projects according to the Board's classifications are normal capital expenditures. This situation provides an opportunity to increase regulatory efficiency.

With the 2017 CBA, Hydro consolidated planned terminal station-sustaining work into the Project. Additionally, Hydro submitted the Terminal Station In-Service Failures to cover the replacement or refurbishment of failed equipment, or incipient failures. Hydro is utilizing the Asset Management Overview as a reference for both projects to streamline and focus information submitted. The Asset Management Overview provides supporting information which was historically, annually presented for similar classification projects in the CBA. The remainder of this document provides information as to the assets involved, an overview of each asset program, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

Hydro will provide an updated Asset Management Overview as it implements changes to its asset management philosophies appropriate for inclusion in the Asset Management Overview.

1.1 Changes in Version 6

Hydro submitted Version 6 of this document in the 2022 CBA. All material updates in this version are shaded in grey and are summarized below:

- Addition to Section 4.1.1: added system concern as a criterion for instrument transformer replacements; and
- Removed frequency monitoring additions from Section 4.3.1.

Minor changes to syntax have been made to improve readability. These minor changes have not been shaded.

2.0 Background

2.1 Newfoundland and Labrador Hydro's Terminal Stations

Terminal stations play a critical role in the transmission and distribution of electricity. Terminal stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system, and interface points with the lower voltage distribution and generation systems. Hydro has 69 terminal stations throughout Newfoundland and Labrador.

2.2 Terminal Station Infrastructure

Stations contain the following infrastructure, which is described throughout this report:

- Transformers;
- Circuit breakers;
- Instrument transformers;
- Disconnect, bypass, and ground switches;
- Surge arresters;
- Grounding;

- Buswork;
- Steel structures and foundations;
- Insulators;
- Control buildings;
- Protection and control relays;
- Yards, fences, and access roads;
- Battery banks;
- Terminal station lighting; and
- Synchronous condensors

Many of Hydro's terminal stations were constructed in the 1960s. Annual capital commitment is needed to sustain terminal station assets to ensure that Hydro can continue to provide customers with reliable electrical service.

3.0 Terminal Station Capital Projects

3.1 Historical Terminal Station Capital Projects

In the 2016 CBA there were 22 individual terminal station projects which accounted for $30 million, or 16% of the capital budget. Historically, Hydro's terminal station projects were divided into two categories: (1) stand alone and (2) programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets, such as disconnects or instrument transformers, and have similar justification and other information presented each year. Of the 22 individual terminal station projects proposed in 2016, 15 were program-type projects. In the 2017 CBA, Hydro consolidated the historical station projects into the Project.

3.2 Hydro's Approach to Terminal Station Capital Project Proposals

The programs now included in the Project are:

- Upgrade circuit breakers;
- Replace disconnect switches;
- Install fire protection;

- Replace surge arresters;
- Upgrade terminal station foundations;
- Refurbish control buildings;
- Replace station lighting;
- Replace battery banks and chargers;
- Upgrade terminal station for mobile substation;
- Install breaker bypass switches; and
- Protection and control refurbishment and upgrades.[2]

The Project excludes:

- Transformer replacement and transformer spares: Although transformer replacement fits within the description of a terminal station program, these projects often have unique justification and a high project cost and, therefore, are proposed separately.
- Activities which cannot be scheduled for inclusion in a CBA, as these will be submitted as either supplemental to the CBA or executed in the Terminal Stations In-Service Failures project.
- Activities in response to additional load or reliability requirements, as these projects generally have unique justification and will be proposed separately.
- Activities in response to significant isolated issues in a particular station such as replacement of a failed power transformer, as these projects generally have unique justification, the projects will be proposed separately.

Hydro continues to maintain individual records with regards to asset capital, maintenance, and retirement expenditures and performance, which will be queried to support the development of the annual capital plan.

[2] As noted in the "2017 Capital Budget Application," Newfoundland and Labrador Hydro, July 28, 2016, vol. II, tab 13, the 2016 Upgrade Terminal Station Protection and Control Upgrade, Upgrade Protective Relays, Upgrade Fault Recorders, Upgrade Data Alarm Systems, and Install Breaker Failure Protection projects were combined in the Asset Management Overview and the Project as the Protection and Control Refurbishment and Upgrades Program.

This document is submitted to the Board as part of the 2022 CBA. Hydro will annually submit proposals for the Terminal Station Refurbishment and Modernization project and Terminal Station In-Service Failures project referencing the most recent Asset Management Overviews. Future CBAs will not include a copy of the Asset Management Overview unless Hydro revises its contents. When the Asset Management Overview is revised, Hydro will clearly denote such changes, highlighted in grey, for review and approval by the Board.

3.3 Benefits of This Approach

As supporting information for programs changes infrequently, referencing the Asset Management Overview in the Project documentation will eliminate the preparation and review of repetitious information. Hydro estimates that this approach could save up to $120,000[3] annually, not including time and costs for review by the Board and parties.

Hydro has a proactive Asset Management System which strives to anticipate future failures so that refurbishment or replacement can be incorporated into a CBA. However, there are situations were immediate refurbishment or replacement, which has not be included in an CBA, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure so as to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging terminal station assets unanticipated failures may increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a Terminal Station In-Service Failures project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

Hydro expects the Project will provide opportunities whereby Hydro can further optimize capital and maintenance work so as to minimize outages to customers and equipment as personnel look to further coordinate work by location.

[3] If the work undertaken in Hydro's 2017 Capital Budget Application's Terminal Station Refurbishment and Modernization project had been submitted as 12 individual projects, it is estimated preparation would be approximately $10,000 per project.

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High-Voltage Instrument Transformer Replacements

The protection, control, and metering devices such as protective relaying, power quality monitors, and kWh meters used in generation and transmission systems are not manufactured to handle the currents and voltages inherent to those systems. Measurement of the electricity's currents and voltages are provided to these devices through a current transformer and a potential transformer, respectively. Current transformers and potential transformers are collectively known as instrument transformers. Hydro has approximately 900 individual high-voltage instrument transformers within the Island and Labrador Interconnected Systems.

A high-voltage instrument transformer consists of an insulated electrical primary and secondary winding, tank, and bushing components. The insulation system involves the use of insulating oil or dry type insulation and a high-voltage porcelain bushing which allows the safe connection of the winding to high-voltage conductors. The winding is enclosed in a steel tank.

Figure 1: 69 kV Current Transformer (Left) and Potential Transformer (Right)

Hydro manages planned budgeted Instrument Transformer replacements in five categories:

1) Condition
2) Polychlorinated Biphenyl Compliance Replacements
3) Manufacturer and model
4) Age; and
5) System Concern.

Condition

Deterioration or damage to the various instrument transformer components can result in the failure of the unit to provide accurate measurements to metering, protection, and control devices, which may affect the safe and reliable operation of the generation and transmission systems. Failure could also result in an oil spill. Also, in some situations pieces of the instrument transformer may be forcibly projected resulting in a safety risk for personnel in the area or damage to other infrastructure.

Damage to an instrument transformer normally results from vandalism, impacts from catastrophically failed equipment, or accidental contact of mobile equipment. Upon such incidents, Hydro assesses the electrical and physical integrity of an instrument transformer to determine if replacement is required.

Hydro monitors instrument transformers for physical and electrical deterioration by conducting regular visual inspections of the units as part of its station inspection program plus regularly scheduled station infrared inspections and electrical insulation testing.

Physical deterioration involves conditions such as oil leaks, rusting, or small chips and cracks in the insulation. Figure 2 shows an example of rusting on a potential transformer tank.

Figure 2: Rusting Potential Transformer

Electrical deterioration is identified by conducting power factor testing at intervals which is used to establish the rate and level of insulation degradation. Hydro uses Doble Engineering Company to provide assistance with assessment of the test results, as required.

On an ongoing basis, Hydro's asset management personnel review the unit deterioration information and determine when corrective maintenance or unit replacement is required. Hydro conducts minor instrument transformer corrective maintenance such as painting and small bushing chip treatment. External services to economically undertake major corrective maintenance or unit refurbishments do not exist, so units requiring major corrective maintenance or refurbishments are replaced.

PCB Compliance Replacements

Environment Canada's PCB Regulations requires that by 2025 all instrument transformers will not have a PCB concentration greater that 50 mg/kg. Instrument transformers are sealed oil filled units, where the oil, which acts as an electrical insulator, has been known to contain PCBs for equipment prior to 1985. Due to the age of the units and the risk of introducing contamination such as air into the unit, which could impact the electrical integrity of instrument transformers, Hydro does not sample instrument transformers. Therefore, establishing the actual PCB concentration in an instrument transformer is not possible. Hydro, in consultation with manufacturers, has established that units manufactured before 1985 are suspected to contain PCBs in concentration levels greater than or equal to 50 mg/kg. Thus Hydro has a program to replace all suspect oil-filled instrument transformers before 2025.

Manufacturer and Model

In 2010, Hydro experienced a failure of a 230 kV Asea IMBA current transformer. The failure analysis recommended this manufacturer and model be replaced over time. These replacements are included in this program. The last of these replacements is planned for 2024.

Age

Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions. Original equipment manufacturers ("OEM") recommend that the life of an instrument transformer is approximately 30–40 years. Recent in-service failures occurred between 20–39 years of life (3 of which occurred between 29–39 years of life).

System Concern

System concern refers to a transient response of a specific make and model of instrument transformer to a specific system transient condition that can contribute to over-stressing (and possibly damage) equipment connected nearby. For example, following four 230 kV circuit breaker failures at Bay d'Espoir Terminal Station 1 during the period of 2018–2019, a transient study identified three instrument transformers with a system concern that likely contributed to over-stressing these circuit breakers and thereby contributed to their failure.

Exclusions from Instrument Transformer Replacement Program

Modern-day circuit breaker technology includes current transformers embedded in the circuit breaker bushings. Therefore, where possible, external current transformers will be displaced by bushing current transformers as circuit breakers are replaced, and such current transformers are not included in this program.

4.1.2 High-Voltage Switch Replacements

High-voltage switches are used to isolate equipment either for maintenance activities or for system operation and control ("disconnect switches"). Switches are also used to bypass equipment to prevent customer outages while work is being performed on the equipment. Disconnect switches are an important part of the Work Protection Code as they provide a visible air gap (i.e., visible isolation) for utility workers. Work protection is defined as "a guarantee that an ISOLATED, or ISOLATED and DE-ENERGIZED, condition has been established for worker protection and will continue to exist, except for authorized tests." Proper operation of disconnect switches is essential for a safe work environment and for reliable operation.

The basic components of a disconnect switch are the blade assembly, insulators, switch base and operating mechanism. The blade assembly is the current carrying component in the switch and the operating mechanism moves it to open and close the switch. The insulators are made of porcelain and insulate the switch base and operating mechanism from the current carrying parts. The switch base supports the insulators and is mounted to a metal frame support structure. The operating mechanism is operated either manually, by using a handle at ground level to open and close the blade, or by a motor-operated device, in which case the switch is known as a motor-operated disconnect. A disconnect and its associated components are shown in Figure 3.

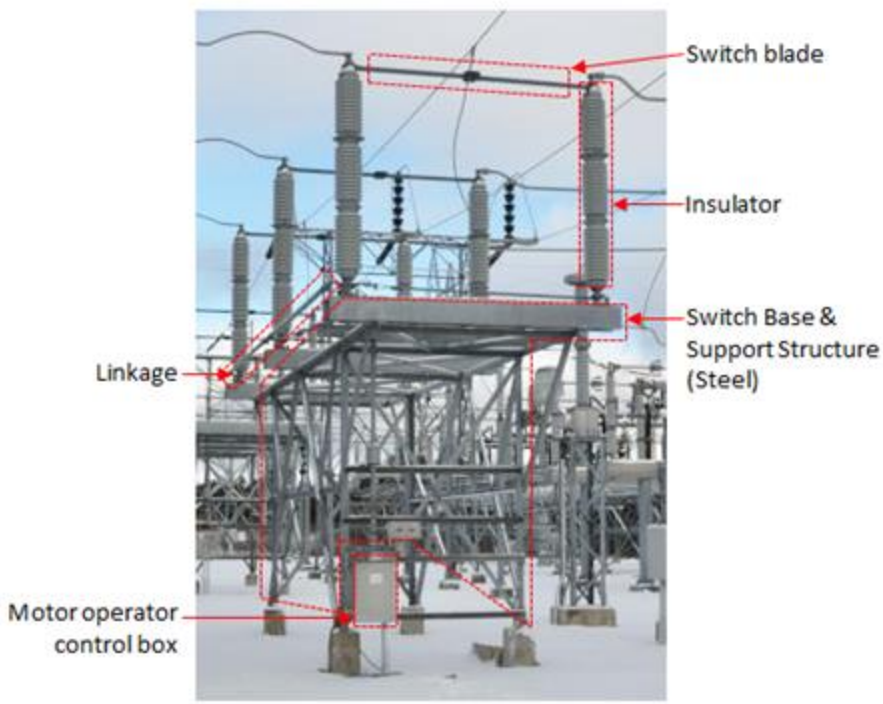

Figure 3: Various Components of a High-Voltage Disconnect Switch

Hydro monitors the condition of its switches by conducting regular visual inspections of the units as part of its station inspection program and its infrared inspection program and by reviewing reports from the JDE E1 work order system or staff who operate the switch, outlining problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If the required parts are available then repairs are undertaken as part of ongoing maintenance. Switches that have operating deficiencies and have reached a service life of 50 years or greater are designated for replacement. Switches that have no replacement parts available due to obsolescence, damaged beyond repair, or cannot be economically repaired and do not require immediate replacement are designated for replacement under this program.

Figure 4 shows an example of a badly damaged disconnect switch.

Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrester Replacement

Surge arresters (also known as lightning arresters) are used on critical terminal station equipment to protect that equipment from voltage due to lightning, extreme system operating voltages, and switching transients, collectively called “overvoltages.” In these situations, voltage at the equipment can rise to levels which could damage the equipment’s insulation. The surge arresters act to maintain the voltages within acceptable levels. Without surge arresters, equipment insulation could be damaged and faults could result during overvoltages. Hydro typically has surge arresters installed on the high- and low-voltage sides of power transformers rated 46 kV and above.

Figure 5 shows the arresters on a 230 kV power transformer.

Figure 5: Western Avalon Terminal Station Transformer T3 230 kV Surge Arresters

Surge arresters can fail because of the cumulative effects of prolonged or multiple overvoltages. When a surge arrester fails, it is not repairable and must be replaced immediately otherwise the major equipment may be exposed to damaging overvoltages. The older arrester designs have a higher incidence of failure than the newer designs.

Hydro's surge arrester asset management program replaces surge arresters based upon the following criteria:

- Removal of gapped type arresters with zinc oxide design due to enhanced performance;
- Replacement of units due to a condition identified through visual inspections for chips or cracks or electrical testing such as power factor testing;
- If failures occur on a given transformer, all arresters on both the high and low side are considered for replacement either immediately or in a planned fashion; and

- If transformers are being planned for maintenance or other capital work, consideration is given to changing aged arresters on a common outage. Hydro targets replacement at 40 years of age, to reduce the risk of in-service failures and minimize service interruptions.

4.1.4 Insulator Replacement

Insulators provide electrical insulation between energized equipment and ground. When an insulator fails and a fault occurs, safety hazards and/or customer outages may occur.

Insulators consist of insulating material such as glass, porcelain, and metal end fittings to attach the insulator to the structure and the conductor. The metallic hardware is mated with the porcelain or glass insulator using cement. There are different styles of insulators. An example of a station post insulator is shown in Figure 6.

Terminal stations contain post type, cap and pin-top, multi-cone, and suspension type insulators.

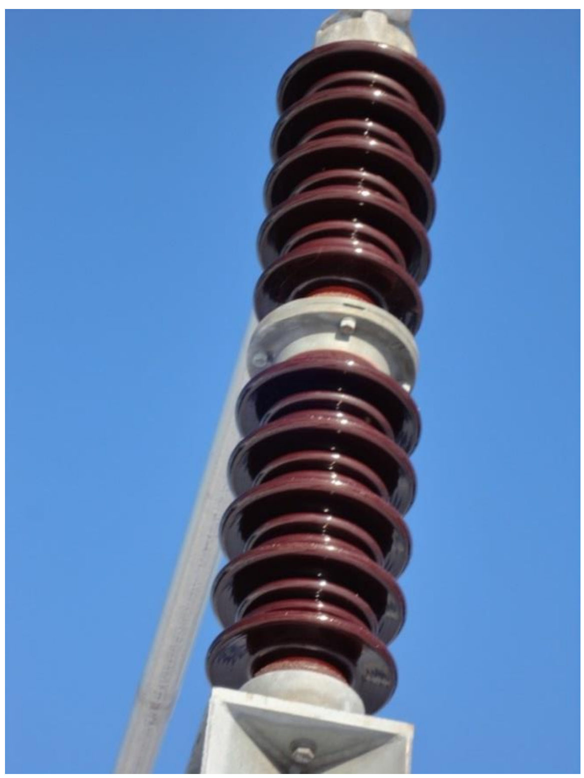

Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

For insulators using porcelain, cement is used in mating the porcelain and metal hardware. Some older insulators have been damaged by a phenomenon known as cement growth. This is a common problem in the utility industry. In such situations, water is absorbed into the concrete, during freeze/thaw cycles, causing swelling of the cement placing stress upon the porcelain. Over time, the increasing pressure caused by cement growth will crack or break the porcelain resulting in insulator failure. In such situations, porcelain may fall presenting a safety hazard to crews or damaging equipment below. Also faults resulting in outages to customers often occur, when insulator failure leads to flash over. Some time ago, insulator manufacturers identified and researched cement growth problems and have improved their cement quality to eliminate this problem.

Hydro carries out detailed insulator surveys by geographical area. Hydro identifies any insulator types known to be prone to failure due to cement growth and replaces these insulators under this program.

4.1.5 Grounding Refurbishment and Upgrades

The grounding system in a terminal station or distribution substation consists of copper wire used in the ground grid under the station, gradient control mats for high-voltage switches, and bonding wiring connecting the structure and equipment metal components to the ground grid. In the event of a ground fault, electrical potential differences will exist in the grounding system. If the grounding system is inadequate or deteriorated these differences may be hazardous to personnel. These potential differences are known as step and touch potentials. Effective station grounding reduces these potentials to eliminate the hazard.

Figure 7: Typical Grounding Connection on Terminal Station Fence

To determine whether grounding upgrades are required, Hydro performs a step and touch potential analysis of the terminal station or distribution substation. Step and touch potential analysis involves the gathering of field data and conducting analysis in order to determine if ground grid modifications are required to eliminate step and touch potential hazard. This engineering is conducted in accordance with IEEE[4] Standard 80-2000. Grounding systems with hazardous step and/or touch potentials are upgraded, by adding additional equipment bonding, gradient control mats, or copper wire to the station grounding grid. In the case where the terminal station grounding infrastructure has deteriorated with age, or is damaged due to accidental contact or vandalism, the grounding system is refurbished by repairing damage or replacing missing infrastructure. Upgrades and refurbishments are made in accordance with Hydro's Terminal Station Grounding Standard.

4.1.6 Power Transformer Upgrades and Refurbishment

Power transformers are a critical component of the power system. Transformers allow the cost-effective production, transmission, and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system and allow for economic construction and operation of the electrical system.

Hydro has 118 power transformers and three oil-filled shunt reactors 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

The basic components of a power transformer are:

- Transformer steel tank containing the metal core and paper insulated windings, oil which is part of the insulating system, and a gasket system which keeps the oil from getting into the environment;
- Bushings mounted to the top of the transformer tank, which connects the windings to the external electrical conductors;
- Radiators and cooling fans, which remove heat for the transformer's internal components;
- On-Load tap changer, which is a device attached internally or externally through which transformer voltages are maintained at acceptable levels; and

[4] Institute of Electrical and Electronics Engineers ("IEEE").

- Protective devices to ensure the safe operation of the transformer such as gas detector relays, oil level and temperature relays, and gauges.

Figure 8 shows a picture of a 75 MVA, 230/66 kV power transformer at the Hardwoods Terminal Station.

Figure 8: Power Transformer

Transformers are expensive components of the electrical system. Hydro, like many North American utilities, is working to maximize and extend the life of its transformers by regularly assessing their condition; executing regularly scheduled maintenance and testing and undertaking refurbishment or corrective actions as required. Transformers regularly undergo visual inspection as part of Hydro's terminal station inspection and scheduled preventive maintenance and testing, to identify concerns regarding the following transformer conditions:

- Insulating oil and paper deterioration;

- Oil moisture content;
- Oil leaks;
- Tank, radiators, and other component rusting/corrosion;
- Tap changer component wear or damage;
- Damaged/deteriorated and PCB-contaminated bushings;
- Failure of the protective devices; and
- Cooling fan failures.

Details on the assessment procedures and corrective action for each of these concerns are provided below.

Transformer Oil Deterioration

The insulating oil in a transformer and its tap changer diverter switch is a critical component of the insulation system. Normal operation of a transformer will cause its oil to deteriorate. Deterioration results from a number of causes such as heating, internal arcing of electrical components, or ingress of water moisture into the transformer. Deterioration of the oil will affect its function in the insulation system and may damage the paper component of the insulation system. Unacceptable levels of deterioration can affect the reliable operation of the transformer. To ensure that the oil in a transformer is of an acceptable quality, Hydro has an oil monitoring program, in which an oil sample is obtained periodically[5] from each transformer and analyzed by a professional laboratory. The test results are assessed to determine the level of deterioration. If an unacceptable level of deterioration is identified, required corrective action is identified by asset management personnel. This action entails either the refurbishment of the oil to improve its quality or the replacement of the oil.

Moisture Content

Oil samples are also analyzed to determine their moisture content. Moisture in a power transformer may be residual moisture or may result from the ingress of atmospheric moisture. Oil and insulating paper with high moisture content has a reduced dielectric strength; therefore, its performance as an electrical insulator is diminished. To address transformers with high moisture content, Hydro will either

[5] The sampling period is annual for most transformers and tri-annually for some.

install an online molecular sieve dry-out system (which circulates and dries the transformer oil without requiring an equipment outage) or perform a hot oil dry out (which circulates and dries the transformer oil and requires an equipment outage).

Oil Leaks and Corrosion

Transformer oil leaks are an environmental hazard and as oil is part of the insulation system, unchecked leaks can affect the safe and reliable operation of a transformer. Leaks can be caused by a number of factors, including failed gaskets or severely corroded radiators, tank piping, and other steel components. Transformers are visually inspected for leaks as part of the regularly scheduled terminal station inspection program and assessed by asset management personnel to determine the level of corrective action. Minor action such as small repairs, patching, and minor painting is undertaken as part of the maintenance. Work requiring major refurbishments and replacements such as radiator or bushing replacements, gasket replacements and tank rusting refurbishment is undertaken under this program.

On-Load Tap Changer

On-load tap changer diverter switches, which are externally mounted on the tank, adjust the voltage by changing the electrical connection point of the transformer winding. This involves moving parts, which are subject to wear and damage. Additionally, in older non-vacuum designed diverter switches, arcing occurs during the movement, leading to deterioration of the insulating oil. This wear and deterioration can lead to failure of the tap changer. Oil testing techniques have been developed by professional laboratories which provide assessments of the condition of the parts and oil. Oil samples are obtained annually from each on-load tap changer to perform a tap changer activity signature analysis by the laboratory. This analysis provides a condition assessment of the tap changer oil and components. Hydro typically implements the laboratory’s sampling interval recommendations. This ranges from continued or increased annual sampling, planned refurbishment, or immediate removal from service, inspection, and repair. The latter two activities are covered by this project. Another component covered by this project is to correct leaking seals between tap changer diverter switches and the transformer main tank. Currently, Hydro has several transformers that show low levels of combustible gases, such as acetylene, due to gasses migrating from the tap changer diverter switch compartment to the main tank.

Bushings

In addition to the aforementioned leaking bushings, Hydro must also address suspected bushings to have PCB levels not compliant with the latest PCB regulations, as well as bushings with degraded electrical properties.

The latest regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg. Hydro has approximately 450 sealed bushings that were manufactured prior to 1985 which are suspected to contain PCBs greater than 50 mg/kg. Some sealed bushings have sampling ports to allow sampling; however, Hydro does not sample due to small quantity of oil in bushings and the risk of contamination during sampling. Bushings which are known or suspected of having unacceptable PCB levels are replaced.

Hydro performs power factor testing on bushings every six years as part of the transformer preventive maintenance. When power factor results indicate unacceptable electrical degradation, bushings are scheduled for replacement.

Protective Devices and Fans

Protective devices and cooling fans are tested during visual inspections and preventive maintenance, and are replaced when they fail to operate as designed or their condition warrant replacement. In addition, cooling fans are added where additional cooling is required due to increased loads.

Online Oil Analysis

In addition to oil quality, dissolved gas analysis ("DGA") is performed on oil. DGA analyzes the levels of dissolved gases in oil, which provides insight into the condition of the transformer insulation. The presence of gases can indicate if the transformer has been subjected to fault conditions or overheating, or if there is internal arcing or partial discharge occurring in the windings. The annual oil sample test can only provide an analysis of transformer condition at the time when the sample is taken. In 2015, as part of this program, Hydro began installing online dissolved gas monitoring on generator step-up ("GSU") transformers, to allow real-time, continuous monitoring of dissolved gases in oil. This continuously monitors the transformer and provides early fault detection. Continuous data is also a useful tool for personnel to use to trend gases to help schedule repairs or replacement prior to in-service failures, improving the overall reliability of the Island Interconnected System. Continuous monitoring enables Hydro to reduce unplanned outages and lessen the probability of equipment in-service failure.

This program was extended to non-GSU transformers in 2017, with online DGA being installed on critical power transformers on the Island Interconnected System. The factors used to determine the criticality score were submitted to the Board in a report on the June 2, 2014.[6] Hydro has identified 49 transformers for installation of online DGA devices between 2019 and 2024.

4.1.7 Circuit Breaker Refurbishment and Replacements

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers through its fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect reliability and safety of the electrical system resulting in failure of other equipment and the occurrence of an outage affecting more end users. Hydro has over 230 terminal station circuit breakers in service with a voltage rating of 46 kV or greater.

Currently, Hydro maintains three different types of high-voltage circuit breakers:

1) Air blast circuit breakers use high-pressure air to interrupt currents and will be at least 38 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained to replace air blast circuit breakers on an accelerated schedule by the end of 2020. This work is covered under a separate project and is not part of the work outlined in the Asset Management Overview. Hydro has since modified this program and is targeting completion in 2023.
2) Oil circuit breakers use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained for the replacement of ten oil circuit breakers up to 2020 which were not compliant with Environment Canada’s PCB regulations. Hydro has since modified this program and is targeting completion of that scope in 2022. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

[6] “Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers,” Newfoundland and Labrador Hydro, July 2, 2014.

3) Sulphur hexafluoride (“SF_6”) circuit breakers use SF_6 gas to interrupt current and installation of these breakers started in 1979 and continue for all new installations.

Figure 9: Air Blast Circuit Breakers (Left), SF_6 Circuit Breakers (Middle), and Oil Circuit Breakers (Right)

As presented in the 2016 CBA project Upgrade Circuit Breakers – Various Sites, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. In 2018, Hydro added 66 kV-rated breakers to also be refurbished after 20 years. Replacement of SF_6 circuit breakers rated at 66 kV and above will be planned after 40 years of service. However as SF_6 circuit breakers come due, a further condition assessment will be completed to determine if more life can be achieved through other means such as an overhaul. Some SF_6 circuit breakers may require replacement before the 40-year service life period based upon their condition and operational history. Hydro expects to replace an average of seven breakers and overhaul three breakers per year for the 5-year period from 2022 to 2026.

4.1.8 Station Service Refurbishment and Upgrades

The power required to operate the various terminal station and distribution substation, collectively referred to as “station” equipment and infrastructure, is provided by the station service system. The station service system provides ac[7] and dc[8] power to operate the equipment in a station.

The ac station service is generally supplied by one or more transformers in the station. Due to their criticality, 230 kV terminal stations have a redundant station service feed, feed either through a redundant transformer tertiary, supplied from Newfoundland Power’s electrical system where available, or by a diesel generator. Common ac station service loads are:

[7] Alternating current (“ac”).
[8] Direct current (“dc”).

- Transformer cooling fans;
- Anti-condensation heaters;
- Station lighting;
- Control building HVAC;[9]
- Control building lighting;
- Air compressors; and
- Battery chargers.

The dc station service is supplied by a battery bank which is charged from the ac station service. The dc station service provides power to critical devices in the station and is designed to allow operation of the station in the event of an ac station service failure. Hydro's dc station service system is a 125 V system in the majority of the stations with some lower voltage stations and telecommunications equipment having 48 V systems. Common dc station service loads are:

- Circuit breaker trip and close circuits and charging motors;
- Protection relays;
- Emergency lighting;
- Disconnect switch motor operators for local/remote operation; and
- Telecommunications equipment.

As terminal station equipment is replaced, added, or upgraded, the ac and dc station service loads may increase. Upon the installation of new equipment in the terminal station, Hydro carries out a station service study to determine the loading on the station service system. In the event that the new station service loads exceed the design load of the system, upgrades such as cable, circuit breaker panel, splitter, and transfer switch replacements or additions are required. Replacement of station service transformers is not included in this program as they are addressed separately in the CBA, under the Replace Power Transformers project, if required.

[9] Heating, ventilation, and air conditioning ("HVAC").

4.1.9 Battery Banks and Chargers

Battery banks and their chargers supply dc power to critical station infrastructure, such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment. Battery banks are designed to provide a minimum of eight hours of auxiliary power to critical infrastructure in the event of a loss of ac station service supply. The majority of Hydro's battery banks consist of lead-acid flooded-cell type batteries whose capacity deteriorates over time. Hydro currently completes discharge testing on criticality A and B battery banks (after 10 years and then every 5 years for flooded cell and every 2 years for valve regulated) and will plan replacements if the battery bank's capacity has fallen to 80% or less of its rated capacity. Also, due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years while valve-regulated lead-acid batteries are replaced after 10 years.

Figure 10: 125 Vdc Terminal Station Battery Bank

4.1.10 Install Breaker Bypass Switches

High-voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed from service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems,[10] this alternate path is accomplished using a bypass switch. When closed, the bypass switch allows electricity

[10] A radial system is an electrical network that has only one electrical path between the source and the load.

to flow around the breaker allowing the breaker to be safely de-energized while maintaining service continuity.

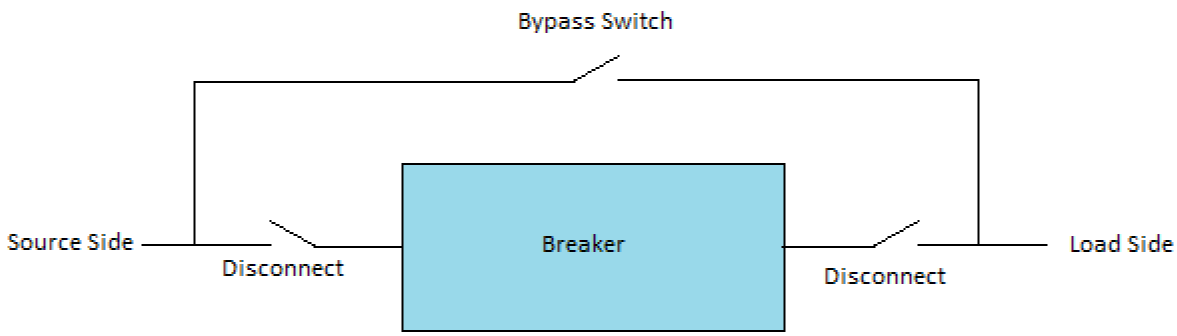

Figure 11: Example of Bypass Switch Installation

Listed in Table 1 are five radial systems, servicing multiple customers, where breakers are installed without bypass switches. In order to ensure service continuity during breaker downtime, Hydro is considering installation of breaker bypass as noted in Table 1.

Table 1: Circuit Breakers Without Bypass Switches

Breaker Location	Customers Affected
Bottom Waters L60T1	2,253 Bottom Waters area customers
Buchans B2T1	665 Buchans area Newfoundland Power customers and Duck Pond Mine
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1,900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2,340 South Brook area customers.

Hydro put a hold on this program in 2018 and is looking closer at only doing this work when other major terminal station work is planned or if there is a low-cost solution. Doyles B1L15 had a low-cost bypass installed in the first quarter of 2020 through an in-service failure project to facilitate the topping up of an ongoing leak in breaker B1L15.

4.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment, as well as for deterring theft and vandalism in terminal stations. Hydro utilizes a variety of lighting technologies and configurations, depending on the application and vintage of the lighting system. Over time, exposure to the elements can cause physical deterioration, such as corrosion, leading to moisture ingress which impacts the function of the lighting system. Additionally, some legacy lighting technologies have become obsolete.

Under this program, Hydro will replace deteriorated lighting systems as they become unable to provide adequate illumination of the terminal station and have become obsolete or beyond repair. Hydro will replace legacy lighting systems with modern, efficient lighting technologies whenever possible.

Figure 12: Corroded Ballast Requiring Replacement

Figure 13: Light Fixture Showing Perforations due to Corrosion, Enabling Moisture Ingress

4.1.12 Synchronous Condensers

Hydro maintains two synchronous condensers located at Wabush Terminal Station. Each condenser undergoes major and minor inspections on a three-year rotating cycle with minor inspections performed on both year one and year two of the cycle, and a major inspection performed on year three. Each involves a standard list of checks, tests, and general maintenance as well as any additional items that have been identified for follow-up based on the results of previous inspections.

The minor inspections involve function testing, vibrations checks, lube oil system maintenance and oil sampling, disassembly and inspection of top half of bearings, clearance checks, electrical tests, visual inspections, as well as cleaning and general maintenance including replacement of various gaskets, filters and hardware.

The major inspections expand on the same activities performed under the minor inspections by also rotor and stator inspection, disassembly and inspection of the bottom half of the bearings, and replacement of the thrust bearings.

4.2 Civil Works and Buildings

4.2.1 Equipment Foundations

Reinforced concrete foundations support high-voltage equipment and structures in Hydro's terminal stations. The majority of these structures formed part of the original station construction and support critical terminal station equipment and buswork.

The service life of galvanized steel structures varies depending on the operating environment but can exceed 100 years outliving the foundations on which they are built. A number of the foundations in Hydro terminal stations have deteriorated significantly due to repeated exposure to damaging freeze/thaw cycles, weathering, and age, leading to concerns over their integrity. Examples of degraded structure foundations are shown in Figure 14 and Figure 15

Figure 14: Structure B1T1 Bottom Brook Terminal Station

Figure 15: Structure L01L37-1 Western Avalon Terminal Station

To ensure foundations perform as per the original design intent, severely deteriorated concrete foundations must be refurbished or replaced. Failure to complete repairs could result in a catastrophic failure, causing outages or personal injury. Hydro has carried out engineering inspections of all 230 kV stations and identified foundations requiring repairs. Additionally, Hydro performs visual inspections of foundations every 120 days during regular terminal station inspections. Foundations identified for repair are addressed under this program.

4.2.2 Fire Protection

Hydro's terminal station control buildings contain combustible materials. As these facilities are unattended, a fire could spread causing severe damage to protection and control wiring and equipment which would cause extended and widespread outages. Restoration of a terminal station severely damaged by fire to normal operation could take months.

Hydro is installing fire suppression systems in its 230 kV terminal stations to protect the control cabinets and cables and any other critical equipment from being destroyed by a fire without damaging sensitive electronic equipment and wiring.

In the 2015 and 2016 CBA Install Fire Protection projects, Hydro received approval to install fire protection in the Holyrood and Bay d'Espoir Terminal Stations. Due to their criticality, Hydro intends to continue its program to install fire suppression systems in all 230 kV terminal stations.

4.2.3 Control Buildings

Terminal station control buildings contain critical station infrastructure such as protection, control, and monitoring equipment; telecontrol equipment; station service equipment; and compressed air systems. Many control buildings also contain office, breakroom, and washroom facilities for use by Hydro crews when working in the station. As the equipment in control buildings is critical to the function of the terminal station, it is imperative that Hydro ensures the structural integrity, weather tightness, and security of its control buildings. While addressing these issues, Hydro also ensures that building auxiliaries such as electrical, plumbing, and HVAC systems function properly to ensure reliable and safe operation and use of the terminal station and the control building.

Typical refurbishment activities for control building involve replacement of the roof membrane (Figure 16), siding, and doors (Figure 17), and may also include replacement of electrical equipment (such as distribution panels, transfer switches, or low-voltage disconnects), plumbing (such as water service entries and internal plumbing), and HVAC (such as intake and exhaust fans, louvers, heaters, and air conditioning equipment).

In its 2016 CBA, Hydro submitted its "Upgrade Office Facilities and Control Buildings Condition Assessment and Refurbishment Program Asset Management Strategy Plan,"[11] which outlined Hydro's approach to address aging and failing building infrastructure. Hydro will undertake the refurbishment of control buildings under the Project.

[11] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. III, tab 23.

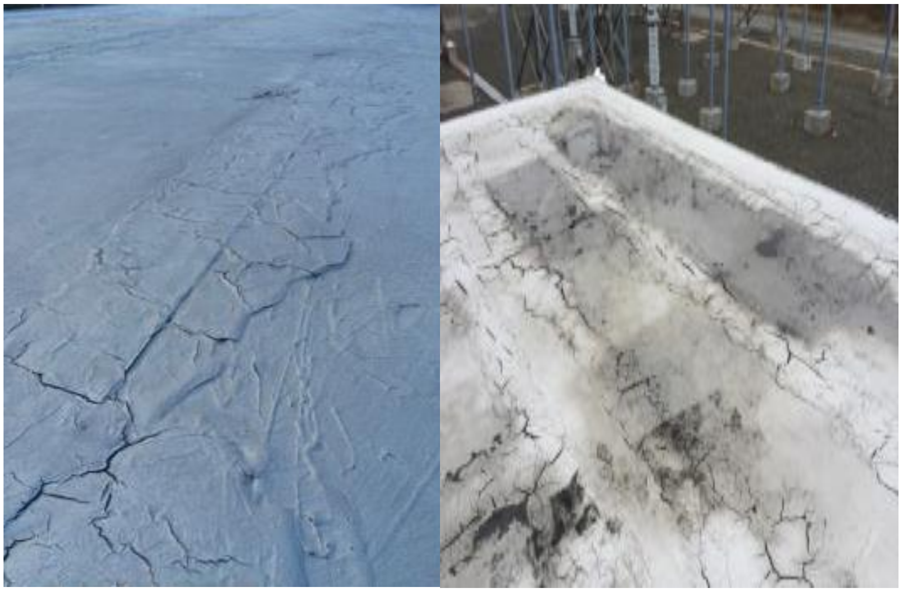

Figure 16: Terminal Station Control Buildings (Come by Chance and Sunnyside) Showing Cracking and Deterioration of the Roof Membrane System

Figure 17: Building Exterior Cladding and Exterior Doorways Displaying Severe Rusting and Deterioration

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

The terminal station protection and control system automatically monitors, analyzes, and causes action by other equipment, such as breakers, to ensure the safe, reliable operation of the electrical system or to initiate action when a command is issued by system operators. The protection and control system also provides indications of system conditions and alarms and allows the recording of system conditions for analysis. Hydro carries out capital work on various protection and control equipment, including:

- Protective relays;
- Breaker failure protection;
- Circuit breaker reclosing controllers;
- Tap changer controls;
- Data alarm systems;
- Digital fault recorders; and
- Cables and panels.

Electromechanical and Solid State Protective Relay Replacement

Protective relays monitor and analyze the operation conditions of the electrical system. When a relay identifies unacceptable operating conditions, such as a fault, it will initiate an action to isolate the source of the condition by commanding high-voltage equipment such as breakers to operate. Protective relays play a crucial role in maintaining system stability and preventing hazardous conditions from damaging electrical equipment or harming personnel.

Older relays existing on Hydro’s system are the electromechanical and older solid state types and lack features such as data storage and event recording capability. Modern digital multifunction relays are used to replace these older style relays as they have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality, and offer greater dependability and security, enhancing system reliability. Digital and electromechanical relays are showing in Figure 18.

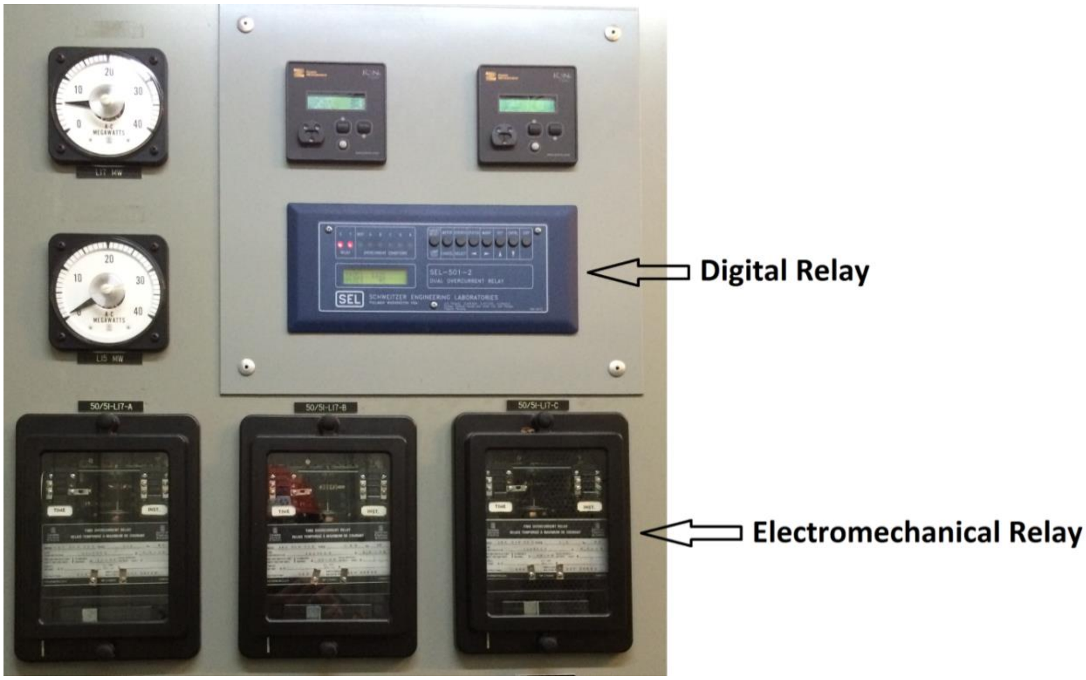

Figure 18: Digital and Electromechanical Relays

In its report dated August 1, 2014,[12] Hydro stated it ". . . plans to review its existing transformer, bus, and line protections in an effort to develop plans for future implementation of modern digital relays with data storage and fault recording capabilities." To fulfill this commitment, Hydro completed the following:

- A review of all transformer, bus, and line protection on 230 kV, 138 kV, and 69 kV systems, including data storage and fault recording capabilities; and
- A plan to replace all existing electromechanical transformer, bus, timer, and line protection relays with modern digital relays. The 230 kV relays are the priority for the first phase of the plan, with 138 kV and 69 kV to follow.

As part of the annual Terminal Station Refurbishment and Modernization project, Hydro will continue to execute the replacement of 230 kV electromechanical and obsolete solid-state transformer, line, and bus relays with modern digital multifunction relays, which began in 2016 under the Replace Protective Relays Program. Additionally, in line with Hydro's response to CA-NLH-037 as part of the 2016 CBA,

[12] "Report to the Board of Commissioners of Public Utilities Related to Alarms, Event Recording Devices, and Digital Relays," Newfoundland and Labrador Hydro, August 1, 2014, at s. 3.1

Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program Hydro will continue to install these upgrades.

Furthermore, in 2021 as part of the annual Terminal Station Refurbishment and Modernization project, Hydro has begun the replacement of protection relays in the Wabush Terminal Station on 46kV feeders. Each replacement is currently planned to coincide with the replacement of the circuit breaker associated with that protection.

Breaker Failure Protection

Protective relaying is designed to trip a breaker during fault conditions to remove the fault from the electrical system so as to minimize equipment outages and maintain system stability and safe, reliable operation. When a breaker does not properly isolate a fault, other breakers will be commanded to trip to isolate the fault. This will result in larger outages but will ensure isolation of the original fault in a time to minimize damage to equipment and minimize impact to the system. The failure of a breaker to isolate a fault when commanded is called a breaker failure.

Prior to 2014, breaker failure protection was implemented only in Hydro's 230 kV terminal stations. In 2014, Hydro completed a review of breaker failure protection in 66 kV and 138 kV terminal stations. Hydro also developed a protection and control standard, Application of Breaker Failure Relaying, calling for breaker failure protection on transmission breakers rated at 66 kV and above. From this review, Hydro identified 20 terminal stations requiring breaker failure protection.

As part of Hydro's 2016 CBA, Hydro proposed and received Board approval for the installation of breaker failure protection in three terminal stations.[13] As part of the annual Terminal Station Refurbishment and Modernization project, Hydro will continue its plan to execute the installation of breaker failure protection in the remaining terminal stations. As well, Hydro has identified concerns with the reliability of legacy breaker failure in 230 kV stations and will be replacing as necessary under this program.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

- Ensure the load bus voltage is regulated as prescribed by the setting;

[13] *Public Utilities Act*, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

- Minimize the current that circulates between the transformers, as would be due to the tap changers operating on inappropriate tap positions; and
- Ensure the controller operates correctly in multiple transformer applications regardless of system configuration changes or station breaker operations and resultant station configuration changes.

Current tap changer controls are of similar vintage as the power transformers dating back to the late 1960s and require replacement. Recent feedback from the tap changer paralleling control supplier indicated older equipment has capacitors that will dry out over time resulting in control issues. Additionally, it was recommended the same controller model be applied to all transformers to optimize tap changing control. The control issues as described by the supplier have been seen by Hydro staff at numerous sites.

Hydro started replacing tap changer paralleling controls in 2019 beginning at the Western Avalon Terminal Station.

Equipment Alarm Upgrades

Alarms inform the Energy Control Centre ("ECC") and operating personnel that equipment and relaying requires attention and are communicated to the ECC and/or displayed locally on the station annunciator.

Figure 19: Annunciator Commonly Found in Hydro Terminal Stations

Hydro's review of alarms, event recording devices, and digital relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

Hydro's internal study identified required increases to alarm detail to the ECC for five 230 kV terminal stations. Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive Terminal Stations were assessed. Hydro proposed and received approval to implement the proposed upgrades at the Stony Brook terminal station as part of the 2016 CBA project Upgrade Data Alarm Systems – Stony Brook.[14] Hydro will continue its plan to install improved data alarm management as part of the Terminal Station Refurbishment and Modernization project, with the remaining stations being addressed in future CBAs.

Digital Fault Recorders

Digital fault recorders record analog electrical data, such as voltage, frequency, and current as well as digital relay contact positions, at a high resolution to allow Hydro to determine the cause and location of an electrical fault. This data allows Hydro to restore service in a timely manner, address system configurations and settings to mitigate the impact of future faults, and improve the protection of critical

[14] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. I, sec. D.

electrical infrastructure. Hydro has digital fault recorders deployed in several stations and has a program to install digital fault recorders in areas where Hydro does not have sufficient coverage to allow the analysis of faults.

Protection and Control Cable and Panel Modifications

This program will cover protection and control panels and wiring that may require alteration, replacement, or addition to existing wiring due to deterioration from environment conditions, accidental damage or the modification/addition of protection and control equipment.

Tab 11: Terminal Station
In-Service Failures

2022 Capital Budget Application

Terminal Station In-Service Failures (2022)

July 2021

A report to the Board of Commissioners of Public Utilities

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Terminal Station In-Service Failures (2022)

Category: Transmission and Rural Operations – Terminal Stations

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in its annual Capital Budget Application. The identification is done through the preventive maintenance program using various condition based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into capital budget applications. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of a failure, the identification of an incipient failure, or determination of faster than anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal electrical system operations, corrosion, etc.

Hydro is proposing that within this project it will undertake the immediate capital refurbishment and replacement work[1] required for terminal stations to maintain safe and reliable operation and to ensure the availability of capital spares[2] required to support such work. These activities will be undertaken in accordance with the philosophies outlined throughout the "Terminal Station Asset Management Overview" (see Volume II, Schedule 8, Tab 10). Examples of the activities that may be undertaken in this

[1] This project excludes work which can be executed as either unforeseen or capital budget supplemental projects.
[2] Capital spares are major spare parts that meet the definition of capital assets that are kept on hand to be used in the event of an unexpected breakdown or failure of equipment thereby expediting the return of the equipment to service. Capital spares are important in reducing periods of interruption in the generation and transmission of electricity.

project are outlined in Appendix A. Hydro uses historical data and the judgement of asset management personnel to predict the magnitude of the Terminal Station In-Service Failures project budget.

2.0 Background

2.1 Operating Experience

The 2020 Terminal Station In-Service Failures project consisted of 11 corrective actions with a total expenditure of approximately $1.1 million. The corrective actions are detailed in Appendix A.

3.0 Project Justification

Due to the nature of terminal station systems and equipment, unanticipated failures and deterioration will occur. This project provides an effective and timely means to undertake the immediate capital refurbishment and replacement work required for terminal stations to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work.

Deferral of work that is justified under this project could result in a detrimental impact to customer power supply or an unacceptable risk to worker or public safety.

4.0 Project Description

Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for its terminal stations to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions; however, throughout 2022, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

The estimate for this project is shown in Table 1. Hydro has reassessed the Terminal Station In-Service Failures project budget for 2022 based on the actual expenditures from 2018,[3] 2019,[4] and 2020[5] and decreased the budget from the $1.8 million proposed and approved in the 2021 Capital Budget Application.

[3] Approximately $2.3 million.
[4] Approximately $1.7 million.
[5] Approximately $1.1 million.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	590.3	0.0	0.0	**590.3**
Labour	136.7	0.0	0.0	**136.7**
Consultant	47.6	0.0	0.0	**47.6**
Contract Work	80.0	0.0	0.0	**80.0**
Other Direct Costs	10.9	0.0	0.0	**10.9**
Interest and Escalation	34.5	0.0	0.0	**34.5**
Contingency	0.0	0.0	0.0	**0.0**
Total	**900.0**	**0.0**	**0.0**	**900.0**

As there is no planned refurbishment or replacement work or capital spares acquisitions, no project schedule is provided for those activities.

Work executed under this project in 2022 will be reported to the Board in Hydro's 2022 Capital Expenditures and Carryover Report, and also provided in 2023 as part of the 2024 Capital Budget Application.

5.0 Conclusion

The Terminal Station In-Service Failures project allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. This project will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support terminal station operations.

Appendix A

2020 In-Service Failure Activities

Table A-1: 2020 In-Service Failure Activities

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Breaker Refurbishment Doyles and St. Anthony Terminal Stations	297.7	B1L15 at Doyles Terminal Station and B1C3 at St. Anthony Terminal Station are 69 kV circuit breakers that had been identified as leaking sulfur hexafluoride (“SF_6”) gas to atmosphere. The leaking of SF_6 to atmosphere is an environmental concern with the gas being known as the most harmful greenhouse gas. Leaking gas could result in a flashover of the breaker or a catastrophic failure resulting in loss of service to customers and compromising the integrity of the electrical system in the area.	The 69 kV breakers B1L15 at Doyles Terminal Station and B1C3 at St. Anthony Terminal Station were refurbished. At Doyles, the terminal station configuration was such that the breaker was unable to be isolated from the electrical system to facilitate the breaker refurbishment. To avoid an extended customer outage, a bypass disconnect switch was installed at Doyles. This bypass arrangement will provide benefits for future maintenance as well.
Transformer T1 On-Load Tap Changer Overhaul St. Anthony Diesel Plant	222.6	A test of the St. Anthony Diesel Plant Terminal Station T1 tap changer identified an abnormal dissipation of energy, indicating fault or wear activity to the extent that there was risk of imminent failure.	Transformer T1 On-Load Tap Changer was overhauled.
Replacement of Four Relay Test Sets Various Locations	214.1	Four relay test sets located at Bishop’s Falls (2005 vintage), Whitbourne (2005 vintage), Stephenville (2005 vintage), and St. Anthony (2007 vintage) failed and required replacement. These sets are used by Protection and Control Technologists to complete preventative maintenance, troubleshooting and projects. Specifically, the relay test sets are used to check the condition of protective relays and current transformer secondary circuits as well as to complete commissioning of new equipment.	Four replacement relay test sets were purchased.
Replacement of Power Transformer Protective Devices Various Locations	152.4	Inspections of 23 power transformer protective devices revealed that the devices had failed or were at risk of imminent failure, due to moisture ingress resulting in electrical contact corrosion.	23 power transformer protective devices were replaced.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Breaker B2T4 Rebuild Bay d'Espoir Terminal Station 1	65.5	In 2019, 230 kV Breaker B2T4 failed and was replaced under the 2019 In Service Failures project. The failed breaker was sent to a factory for rebuild to serve as an onsite spare.	The failed 230 kV Breaker B2T4 was rebuilt by the original equipment manufacturer ("OEM") and returned to Bay d'Espoir in 2020 as an onsite spare. The OEM covered the factory rebuild cost and Hydro covered the shipping costs to and from the factory.
Purchase Spare Disconnect Switch Bay L'Argent Terminal Station	40.7	In 2019, a 145 kV disconnect was used from the stand-by equipment pool to replace a failed disconnect switch at Bay L'Argent Terminal Station. In order to maintain adequate spare availability, a replacement 145 kV disconnect was required.	One spare 145 kV disconnect switch was purchased for the stand by equipment pool.
Synchronous Condenser 2 ("SC2") Human Machine Interface ("HMI") Upgrade Wabush Terminal Station	23.2	The existing HMI for SC2 was no longer functional and vendor support for the associated software was discontinued. The HMI is required to provide oversight of operating parameters and access to logged historical operating data for the synchronous condenser. Failure to have access to this data will result in the unavailability of key information for operations oversight, failure/event analysis and management purposes.	The existing HMI for SC2 was upgraded with new software.
Purchase Spare Synchronous Condenser Breaker Wabush Terminal Station	22.1	Synchronous Condenser Breakers 4-1, 12 1A, 12-1B, 4-2, 12-2A, and 12-2B are approximately 50 years old and there have been several issues found with these breakers on recent unit inspections that required emergency repair, which extended the length of the equipment outages. Due to the age and recent maintenance issues of these breakers, it was determined a spare was required in the event of failure.	A spare synchronous condenser breaker was purchased.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Surge Arrester Replacement Holyrood and Massey Drive Terminal Stations	16.3	Surge arresters H1, H2 and H3 on Station Service Transformer SST1-2 at Holyrood Terminal Station and H1 and X1 on Transformer T3 at Massey Drive Terminal Station failed Doble testing during planned preventive maintenance checks, resulting in the requirement for immediate replacement.	Surge arresters H1, H2 and H3 on SST1-2 at Holyrood Terminal Station and H1 and X1 on T3 at Massey Drive Terminal Station were replaced.
Disconnect Switch L2L38 Replacement Holyrood Terminal Station	15.0	On August 31, 2020, an attempt was made to close disconnect switch L2L38. The disconnect switch was inoperable and required immediate replacement.	Disconnect Switch L2L38 was replaced with an available spare.
Replace Bus 13 Differential Protection Relays Bay d'Espoir Terminal Station 2	11.4	Three Bus 13 differential protection relays malfunctioned on three separate occasions in 2020. The relays were electro-mechanical overcurrent type and were obsolete. Immediate replacement was required to ensure protection systems were operating correctly.	Three Bus 13 differential protection relays were replaced.

Tab 12: Wood Pole Line Management Program

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ANDRE C. MARSHALL
SIGNATURE
JULY 28, 2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Wood Pole Line Management Program (2022)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Wood Pole Line Management Program (2022)

Category:	Transmission and Rural Operations – Transmission
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

Executive Summary

The Wood Pole Line Management Program is a condition-based program that uses reliability-centered maintenance principles and strategies.[1] Under the program, data from transmission line inspections is analyzed on an annual basis and recommendations are made, as required, for refurbishment or replacement of line components, including poles, structures, hardware, and conductors. Recommended work is completed in subsequent years. Inspection data and refurbishment or replacement of assets is recorded in a centralized database which is used for future analysis and tracking.

The purpose of the Wood Pole Line Management Program is to detect and treat deteriorating wood poles and line components before the integrity of a structure is jeopardized. If the deterioration of the structure or components is not detected early, the reduced integrity of the structure could affect the reliability of the line. It could also lead to increased failure costs and, potentially, customer interruptions. Safety issues and hazards for Newfoundland and Labrador Hydro ("Hydro") personnel and the general public could also result from wood poles which have weakened structural integrity.

Work planned for 2022 under the Wood Pole Line Management Program is expected to cost approximately $1,603,500.

[1] Reliability-centered maintenance is a maintenance strategy that is implemented to optimize the maintenance program of a company or facility.

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1.0 Introduction

As wood poles age, their preservative retention levels decrease and the poles become increasingly vulnerable to deterioration by different agents, including fungi and insects. Wood poles must be regularly inspected and treated to proactively identify and assess deterioration.

The Wood Pole Line Management Program is an annual program that promotes early detection of deteriorated poles and other line components. Early detection is required to avoid potential safety hazards and identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the expected useful life of the poles. This program is a least-cost strategy to wood pole line management, as investments made in regular inspection and early detection of issues extends the useful life of the poles, supports the deferral of line reconstruction, and prevents forced outages.

2.0 Background

Hydro first initiated the Wood Pole Line Management Program as a pilot study in 2003 and subsequently determined that the program should continue as a long-term asset management and life extension program. The Wood Pole Line Management Program was presented to the Board of Commissioners of Public Utilities ("Board") as part of Hydro's 2005 Capital Budget Application and was entitled "Replace Wood Poles – Transmission."

2.1 Existing System

Hydro maintains approximately 2,300 km of wood pole transmission lines operating at voltages of 69 kV, 138 kV, and 230 kV. These lines consist of over 23,000 poles of varying ages from new to 56 years old. As of 2021, approximately 95% of Hydro's transmission pole assets are more than 20 years old; approximately 55% are more than 40 years old.

Prior to 2003, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections only. In 1998, Hydro began to collect core samples from select poles to test for preservative retention levels and pole decay. The results of early tests raised concerns regarding the general preservative retention levels in the poles. This testing confirmed that there were poles in Hydro's system that had a preservative level below that which is necessary to maintain the required design criteria. During this period, certain poles were replaced because the preservative level had decreased to the point that decay had advanced and the pole was no longer structurally sound.

These inspections and the analysis of the data confirmed that a more rigorous wood pole line management program was required.

Figure 1 illustrates typical wood pole inspection techniques conducted in the Wood Pole Line Management Program. Figure 2 provides examples of wood pole inspection results.

Figure 1: Wood Pole Line Management Inspection Techniques. Clockwise from Bottom Left: (1) Field Data Collector, (2) Installing Boron Treatment, (3) Climbing Inspection, (4) Destructive Testing at Memorial University of Newfoundland

Figure 2: Examples of Wood Pole Inspection Results

Hydro's experience with the Wood Pole Line Management Program has demonstrated that the expected useful life of transmission lines can be extended by more than 15 years through early inspection and refurbishment.

The anticipated useful life of a wood pole transmission line that is not subject to inspection or maintenance is approximately 40 years. As of 2021, Hydro has 27 wood pole transmission lines that have surpassed this anticipated useful life. Of these lines, 22 are over the age of 45 years, with the oldest wood pole line having been installed 56 years ago in 1965. The extension of the useful life of these poles can be attributed to the inspection, treatment, and refurbishment that Hydro has conducted on the transmission lines. For details, please refer to "Interim Report – Review of the Current WPLM Program"[2] and "Progress Report #2 (2012–2017) Review of the Current Wood Pole Line Management (WPLM) Program."[3]

3.0 Justification

There are no viable alternatives to undertaking the activities outlined in this program. The program employs a balanced ten-year inspection cycle that includes inspection, treatment, and replacement, as required, following reliability-centered maintenance principles. Deferral of the program would be detrimental to program execution, effectiveness, and resource balancing.

In 2004, the Board determined that this approach was justified and prudent, stating:

> This approach is a more strategic method of managing wood poles and conductors and associated equipment and [the Board] is persuaded that the new WPLM Program, based on RCM principles, will lead to an extension of the life of the assets, as well as a more reliable method of determining the residual life of each asset. One of the obvious benefits of RCM will be to defer the replacement of these assets thereby resulting in a direct benefit to ratepayers.[4]

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[2] Filed as part of Hydro's "2013 Capital Budget Application," Newfoundland and Labrador Hydro, rev. August 31, 2012 (originally filed August 8, 2012), vol. II, tab 17, app. B. <http://pub.nl.ca/applications/ARCHIVE/NLH2013Capital/files/application/NLH2013Application-WoodPoolLineMgt.pdf>.

[3] Filed as part of Hydro's "2019 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2018, vol. I, 2019–2023 Capital Plan, app. C. <http://pub.nl.ca/applications/NLH2019Capital/applications/2019%20CBA%20-%20Volume%201%20-%20Rev%201%20-%202018-10-09.PDF>

[4] Order No. P.U. 53(2004) Reasons for Decision at p.23/13-18.

Hydro committed to providing the Board with annual updates on the program, including progress summaries of the work completed to date and a forecast of future program objectives. The update is provided in this report.

4.0 Project Description

The Wood Pole Line Management Program is a condition-based program that uses the basic principles and strategies of reliability-centered maintenance. Under the Wood Pole Line Management Program, data from transmission line inspections is analyzed on an annual basis and recommendations are made for refurbishment or replacement of deteriorated line components including poles, structures, hardware, and conductors. Recommended work is generally completed in subsequent years; however, in cases where components are deemed unable to last until the time of their planned refurbishment, Hydro replaces or refurbishes in the current year. Such replacements are managed within the existing budget.

The purpose of the Wood Pole Line Management Program is to detect and treat deteriorating wood poles and line components before the integrity of the structures is jeopardized. If the deterioration of the structures or components is not detected early, the reduced integrity of the structure could affect the reliability of the line and present safety issues and hazards for Hydro personnel and the general public.

The Wood Pole Line Management Program inspection schedule generally plans to complete older lines first and works toward newer lines. The specific lines and the number of poles included in the program are reviewed on an annual basis and may be modified based on the following criteria: age; priority (radial or redundant); and known problems.

Sufficient long-term data derived from two complete ten-year inspection cycles will be required before Hydro can provide the quantitative benefits of the Wood Pole Line Management Program on transmission line reliability. The second Wood Pole Line Management inspection cycle is scheduled for completion by 2023. In the absence of long-term data, transmission line performance during ice storms may provide an indication of how the Wood Pole Line Management Program is impacting reliability.

In March 2008, there was a severe ice storm on the Avalon Peninsula. Hydro's test site at Hawke Hill recorded more than 25 mm of radial glaze ice, which exceeds the design load of the wood poles on the

Avalon Peninsula. There were no reported failures on the poles which were not structurally sound had been replaced during the first Wood Pole Line Management inspection cycle between 2003 and 2007. Additionally, there were no failures of Hydro's wood pole assets on the Avalon Peninsula in the ice storm of March 2010. The performance of these lines during ice storm conditions supports Hydro's continued proactive condition-based management program.

4.1 Historical Information

4.1.1 Historical Expenditures

The five-year historical cost information for the Wood Pole Line Management Program and the budget for 2021 are provided in Table 1.[5]

Table 1: Historical Wood Pole Line Management Program Expenditures ($000)

Year	Budget (A)	Actuals (B)	Difference (C) = (B) – (A)
2021	2,896.9	n/a	n/a
2020	2,792.7	2,882.6	89.9
2019	2,467.0	2,873.4	406.4
2018	3,532.9	3,185.6	(347.3)
2017	2,404.1	3,234.7	830.6
2016	2,919.0	3,180.0	261.0

4.1.2 Historical Replacement Information

Table 2 and Table 3 provide the statistics for pole and pole component replacement for the five-years prior to implementation of the Wood Pole Line Management Program and for the years since implementation of the program.

[5] Per-unit information is not available, as work is not defined by unit (e.g., line or structure number). The work completed varies based on the actual condition of the asset. In most cases, the work completed on any one structure is not related to the work on the next structure (e.g., one structure may require a pole replacement and the next structure may need a crossarm or an insulator replacement). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration, voltage, age, and geographical location of the line.

Table 2: Annual Statistics of Pole and Pole Component Replacement

Year	Poles	Crossarms	Knee Bracing	Cross Bracing
2020	30	54	7	6
2019	32	26	7	9
2018	29	19	1	9
2017	31	32	36	76
2016	38	39	28	23
2015	50	14	15	5
2014	57	11	10	6
2013	34	8	88	8
2012	32	14	4	4
2011	53	19	80	22
2010	60	20	45	58
2009	81	12	14	25
2008	93	27	27	25
2007	97	31	11	19
2006	142	30	18	21
2005	98	47	43	58
2004[6]	51	13	12	22
2003	31	29	13	55
2002	126	53	6	61
2001	21	16	2	2
2000	44	30	21	30
1999	135	7	20	2
Total	**1,365**	**551**	**508**	**546**

Table 3: Statistics of Pole and Pole Component Replacement

Period	Poles	Crossarms	Knee Bracing	Cross Bracing	Comments
1999–2003	357	135	62	150	5 Years Before Wood Pole Line Management
2004–2020	1,008	416	446	396	17 Years Since Wood Pole Line Management

[6] Wood Pole Line Management Program began in 2004.

4.2 Review of 2020 Wood Pole Line Management Program

One of the objectives of the 2020 program was to inspect, test and treat 2,363 poles and associated line components. Table 4 summarizes the 2020 inspections.

Table 4: 2020 Inspections Completed

Regions	Line Name	Year In Service	Voltage Level (kV)	Planned Number of Poles to Inspect	Actual Number of Poles Inspected	Percent Complete[7]
Eastern	TL 219	1990	138	325	327	101%
Central	TL 220	1970	69	170	174	102%
	TL 233	1973	230	410	411	100%
	TL 251	1981	69	119	116	97%
	TL 254	1988	69	216	200	93%
Western	TL 209	1971	230	183	178	97%
	TL 243	1978	138	159	159	100%
Northern	TL 226	1970	69	253	259	102%
	TL 227	1970	69	48	49	102%
	TL 257	1988	69	480	488	102%
Totals				**2,363**	**2,361**	**100%**

Another objective of the 2020 Wood Pole Line Management Program was the refurbishment of defective components identified in previous inspections. A summary of the work completed in 2020 is provided in Table 5.

Table 5: Summary of 2020 Refurbishment

Component	Region				Total
	Eastern	Central	Western	Northern	
Poles	0	12	17	1	**30**
Crossarms	2	44	4	4	**54**
Cross Bracing	-	6	-	-	**6**
Knee Bracing	-	7	-	-	**7**
Foundations	-	1	1	-	**2**
Miscellaneous (Insulators, Hardware, etc.)	29	36	8	45	**118**

[7] Rounded to a whole percentage point.

4.3 Update of 2021 Wood Pole Line Management Program

The inspection and treatment work scheduled for 2021 is summarized in Table 6. This work is scheduled to be executed between June 2021 and October 2021.

Table 6: 2021 Inspection Plan

Region	Line No.	Year Built	Age of Line	Target Number of Poles to Inspect
Eastern	TL 219	1990	31	307
Central	TL 210	1969	52	104
	TL 220	1970	51	8
	TL 222	1967	54	222
	TL 234	1981	40	226
	TL 260	1990	31	301
Western	TL 233	1973	48	314
Northern	TL 241	1983	38	203
	TL 259	1990	31	601
Total				**2,286**

A program to refurbish the issues identified in the 2020 inspection program began in spring 2021 and will continue into fall 2021. This includes the replacement of 22 poles, 27 crossarms, 5 sets of cross bracing, 14 sets of knee bracing, and other components. A list of the refurbishment work scheduled for completion in 2021 is provided in Table 7.

Table 7: 2021 Refurbishment Plan

Component	Region				Total
	Eastern	Central	Western	Northern	
Poles	-	19	-	3	**22**
Crossarms	-	13	13	1	**27**
Cross Bracing	-	3	2	-	**5**
Knee Bracing	-	14	-	-	**14**
Foundations	6	1	-	2	**9**
Miscellaneous (Insulators, Hardware, etc.)	32	51	14	26	**123**

4.4 Budget Estimate

The project estimate shown in Table 8 includes the inspection and treatment of the lines identified for 2022 and the estimated costs of refurbishment or replacement of poles in 2022 which are identified as requiring such work through the inspections.

In 2022, only poles and items deemed as requiring immediate attention will be replaced or refurbished. Required refurbishment identified in 2021 inspections will be scheduled for 2023. This is to introduce a one year gap between inspections and the refurbishment that is identified from them. This "gap year" will allow for better planning and more accurate cost estimating going forward. As such, the 2022 budget for this project, shown in Table 8, is materially less than last year's budget for the Wood Pole Line Management Program as it does not include estimated costs for replacements and refurbishments identified through 2021 inspections, with the exception of those deemed as requiring immediate attention.

The 2021 inspections were not complete as of the date this report was completed. To establish a projected cost of refurbishment or replacement, a percentage of poles inspected are assumed to be requiring refurbishment or replacement based on the Iowa curve (shown in Appendix A) depending on their age and group.[8] Poles rejected in the field will be analyzed with respect to reliability issues, and if rejected after structural analysis, a recommendation to refurbish or replace will be made.

Using the Iowa curve, the anticipated pole replacement rate is calculated and used to estimate the future refurbishment costs. A schedule of the pole inspections from 2021–2026 is provided in Appendix A. Table A-1 also provides the anticipated pole rejection rate for each year.

The Wood Pole Line Management Program budget for 2023 and beyond will be established in future Capital Budget Applications.

[8] Iowa curves display functional failures or retirements of asset classes. They were developed in a study at the University of Iowa. Each curve represents a probability distribution and has a series of attributes. The curves support realistic forecasting of the remaining life of groups of assets.

Table 8: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	63.8	0.0	0.0	**63.8**
Labour	1,012.0	0.0	0.0	**1,012.0**
Consultant	50.0	0.0	0.0	**50.0**
Contract Work	125.0	0.0	0.0	**125.0**
Other Direct Costs	293.6	0.0	0.0	**293.6**
Interest and Escalation	4.9	0.0	0.0	**4.9**
Contingency	54.2	0.0	0.0	**54.2**
Total	**1,603.5**	**0.0**	**0.0**	**1,603.5**

4.5 Project Schedule

The annual project schedule involves many transmission lines and is dependent on the annual work load and availability of outages. Work scheduled for 2022 will commence as early in the year as system conditions allow. The schedule is determined during the spring of each year.

5.0 Conclusion

The Wood Pole Line Management Program is an important part of Hydro's ongoing maintenance. It is aligned with Hydro's responsibility to provide safe and reliable service to customers at the lowest possible cost. Therefore, Hydro proposes to continue the Wood Pole Line Management Program in 2022.

Appendix A

Wood Pole Line Management Inspection Schedule 2021–2026

Table A-1: Wood Pole Line Management Inspection Schedule and Expected Pole Rejection Rates (Summary)

Year	No. of Poles Inspected	Estimated Approximate Pole Rejection Rate	Estimated No. of Poles Rejected
2021	2,286	1.3%	29
2022	2,363	1.1%	26
2023	2,503	1.3%	33
2024	2,256	2.9%	66
2025	2,000	3.9%	77
2026	2,493	3.3%	83

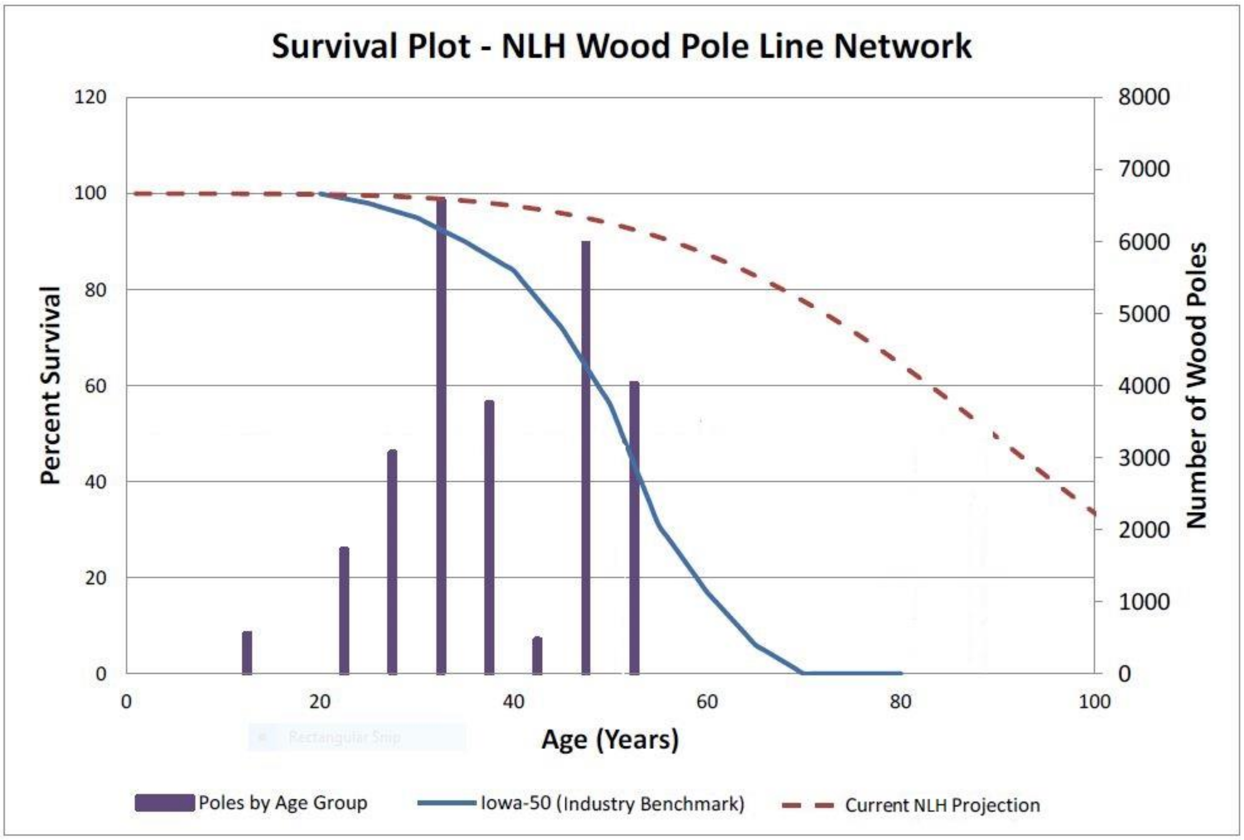

Figure A-1: Iowa Curve

Tab 13: Overhaul Diesel Units

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7/15/21
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NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Overhaul Diesel Units (2022)
Various

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Overhaul Diesel Units (2022) – Various

Category: Transmission and Rural Operations – Generation

Definition: Pooled

Classification: Normal

Investment Classification: Renewal

Executive Summary

To support the continued safe and reliable operation of diesel units, Newfoundland and Labrador Hydro ("Hydro") is proposing to overhaul seven diesel engines and one alternator in 2022 based on forecast operating hours for these units.[1]

Hydro has 23 diesel generating stations, 18 of which are the sole source of power to the community. The two main components of a diesel unit include the engine and alternator. Diesel engines are overhauled or replaced[2] approximately four times during the life of the diesel generation unit ("genset"), while the alternator is overhauled once during the life of the genset. Units are overhauled based on Hydro's established criteria which requires overhaul for 1,200 rpm units every 30,000 operating hours and 1,800 rpm units every 20,000 hours. Overhauls are required to ensure each engine is able to meet its expected life of 120,000 hours for 1,200 rpm units and 100,000 for 1,800 rpm units. The units identified for overhaul in 2022 are all projected to meet the above-noted criteria by 2022.

Diesel generating stations are isolated and, in most cases, are the sole sources of power to the community. Deferral of this program is not appropriate as regular maintenance in accordance with Hydro's established criteria is required to support the units' ability to reliably operate to the full expected life. Further, to defer or skip an overhaul would increase the risk of an engine or generator failure, resulting in reduced reliability of the generating station.

[1] Occasionally, a unit experiences an issue that necessitates an unplanned overhaul or reaches the operating hours at which it requires overhaul earlier than anticipated. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer the completion of one of the planned units. Additionally, should one of the planned units not reach the operating hours required to necessitate overhaul in 2022, Hydro will not complete the overhaul until such time that the criteria for overhaul has been met.

[2] Hydro has determined that in some cases it may be more cost effective to replace the engine with a new one instead of overhauling it. When both overhaul and replacement are options, Hydro will select the least-cost option.

The estimate for this project is $1,360,500 and all planned work is scheduled to be complete by the end of 2022.

Contents

List of Appendices

1.0 Introduction

Hydro has 23 diesel generating stations; 18 of these diesel generating stations are isolated and the sole source of power to the community, serving a total of approximately 4,400 customers. Each generating station has between three and six gensets with rated output from 40 kW to 2,500 kW. The gensets across Hydro's system range in age from less than 1 year to 53 years. As of July 2021, the operating hours on Hydro's gensets range from 535 to over 122,000.

In 2022, the genset models proposed for overhaul within this report are anticipated to reach or exceed the operating hour threshold for recommended overhauls based on the rotational speed of the unit. All of Hydro's gensets operate at either 1,200 or 1,800 rpm.

2.0 Background

A diesel genset is the combination of a diesel engine with an electric alternator[3] used to generate electrical energy as shown in Figure 1. Gensets can be classified in one of three ways, depending on their mode of operation:

1) Continuous;
2) Prime; and
3) Standby/Emergency.

Continuous and prime gensets are similar as they function as the main source of power and are designed to operate continuously or for extended periods of time. The primary difference between the two is that continuous gensets are designed to operate continually with a consistent load while prime gensets are designed to operate for long durations at variable load. Standby/Emergency gensets are to be run only when there is an outage or in a backup situation. For Hydro, prime power gensets are the class purchased based on the mode of operation for use in its isolated locations.

[3] An alternator is an electric generator that converts mechanical energy to electrical energy in the form of alternating current.

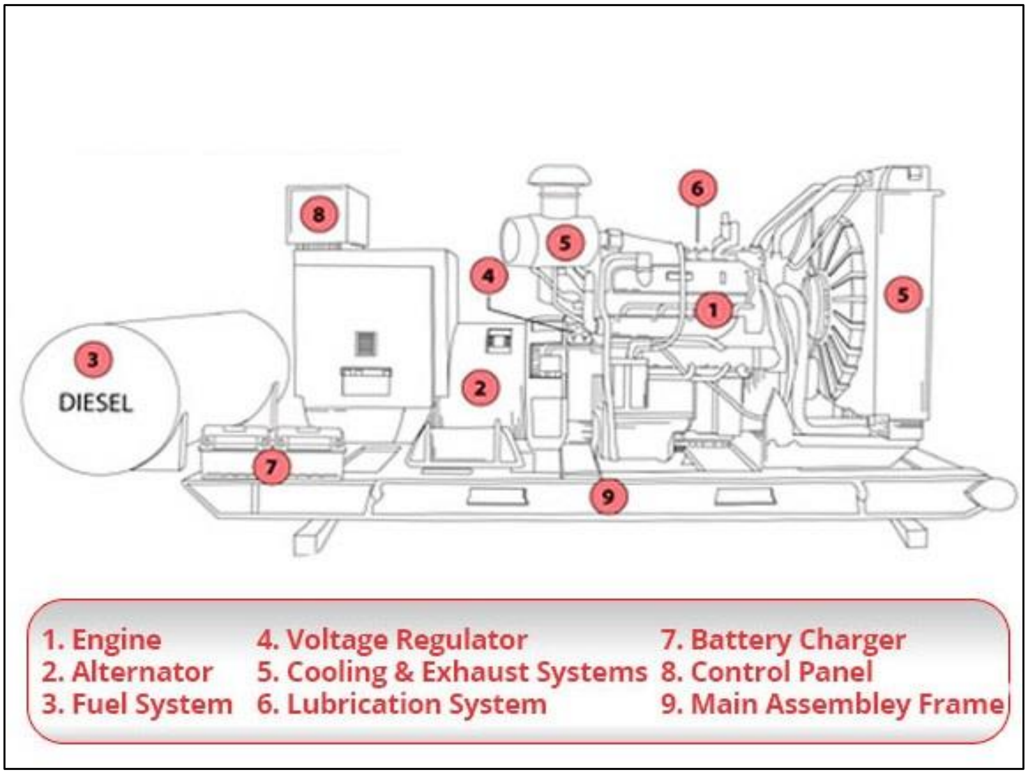


Figure 1: Diesel Genset

2.1 Existing System

Hydro’s prime power gensets are overhauled based on the rotational speed of the unit. Units that operate at 1,800 rpm are overhauled after 20,000 hours of service and units that operate at 1,200 rpm are overhauled after 30,000 hours. For both 1,200 and 1,800 rpm units, the alternators are typically overhauled once in the lifetime of the genset, generally after 40,000–60,000 hours of operation.

The diesel engines and alternator planned for overhaul in 2022 based on their projected operating hours are listed in Table 1.[4]

[4] Occasionally, a unit experiences an issue that necessitates an unplanned overhaul or reaches the operating hours at which it requires overhaul earlier than anticipated. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer the completion of one of the planned units. Additionally, should one of the planned units not reach the operating hours required to necessitate overhaul in 2022, Hydro will not complete the overhaul until such time that the criteria for overhaul has been met.

Table 1: 2022 Planned Overhauls

Genset Location and Unit Number	Engine Rating (kW)	Engine Speed (rpm)	Alternator Rating[5] (kW)	Age (Years)	Year of Last Overhaul
Nain 2085	1,375	1,800	1,275	13	2019
Paradise River 585	88	1,800	50	12	2018
Mary's Harbor 2090	725	1,800	725	9	New
Norman's Bay 581	50	1,800	50	12	2016
Rigolet 2081[6]	529	1,800	455	16	2017
Rigolet 2101	545	1,200	545	4	New
Grey River 2067	232	1,800	136	19	2015

2.2 Operating Experience

All the models identified in Table 1 are operational with most in regular daily service. Hydro maintains an engine overhaul program based on operating hours to maximize the life of its gensets.

3.0 Justification

This project is required to maintain reliable operation of the diesel engines and alternators. Diesel generating stations are isolated and, in most cases, are the sole sources of power to the community. To defer or skip an overhaul would increase the risk of an engine or generator failure, resulting in reduced reliability of the generating station.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Defer overhauls to a future year; and
- Alternative 2: Complete overhauls as planned.

[5] The Alternator Rating is also the rating for the unit, unless the engine rating is smaller.
[6] Both the engine and alternator for Rigolet 2081 are planned for overhaul.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

This alternative involves continued operation of the gensets beyond Hydro’s established and accepted criteria for engine overhauls. Doing so would increase the likelihood of engine failure and reduced reliability for the communities these gensets serve. This presents an unacceptable level of risk and is therefore not recommended.

4.2.2 Alternative 2: Complete Overhauls

Complete the planned overhauls to support the continued safe and reliable operation of Hydro’s diesel generating stations. This alternative is consistent with Hydro’s established criteria for engine overhauls.

4.3 Proposed Alternative

Hydro proposes to complete the planned overhauls to maintain reliable operation of its diesel generating facilities. When both replacement and overhaul options are possible, Hydro will select the least-cost option during execution of the project.

4.4 Replacement versus Overhaul

During the 2018 overhauls, it was determined that the cost of overhaul parts had increased materially and were subject to fluctuation. Based on this information, Hydro has determined that in some cases it may be more cost effective to replace the engine with a new one instead of overhauling it. New engines are also covered by a manufacturer’s warranty. In these cases, the engine must be available for delivery within acceptable time frame. While there are no alternatives to executing the project on an engine that has reached the timing for intervention, when both overhaul and replacement are possible and available options, Hydro will select the least-cost option.

Overhauls which are performed on alternators by a third party, Siemens, have no alternative. The alternators are cleaned and rewound if necessary.

5.0 Project Description

Based on forecast operating hours and Hydro's established criteria for overhaul of diesel units, Hydro has identified the following units to be due for overhaul in 2022:

- Nain 2085 (engine);
- Paradise River 585 (engine);
- Mary's Harbor 2090 (engine);
- Norman's Bay 581 (engine);
- Rigolet 2081 (engine and alternator);
- Rigolet 2101 (engine); and
- Grey River 2067 (engine).

As the cost of parts may fluctuate, Hydro will determine the cost of the overhaul parts and replacement engines in early 2022 and select the least-cost option with acceptable delivery time frames. If an overhaul occurs, it will include replacement or refurbishment of such items as pistons, liners, main bearings, connecting rod bearings, fuel injectors, oil cooler, turbo charger, water pump, oil pump, cylinder heads, fuel lines, fuel pumps, and gaskets.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	832.0	0.0	0.0	**832.0**
Labour	247.2	0.0	0.0	**247.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	20.0	0.0	0.0	**20.0**
Other Direct Costs	75.6	0.0	0.0	**75.6**
Interest and Escalation	70.2	0.0	0.0	**70.2**
Contingency	115.5	0.0	0.0	**115.5**
Total	**1,360.5**	**0.0**	**0.0**	**1,360.5**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Schedule annual overhauls	February 2022	September 2022
Procurement:		
Purchase overhaul components	March 2022	October 2022
Installation:		
Complete overhaul	April 2022	November 2022
Commissioning:		
Testing after overhaul	April 2022	November 2022
Close Out:		
Release for service and asset assignment	December 2022	December 2022

6.0 Conclusion

To support the continued safe and reliable operation of Hydro's diesel units, Hydro is proposing the overhaul of seven diesel engines and one alternator in 2022. Hydro completes overhauls on 1,200 rpm engines after 30,000 hours of operation with replacement after 120,000 hours. Engines that operate at 1,800 rpm are overhauled after 20,000 hours with replacement after 100,000 hours. Hydro has determined, based upon the cost of replacement parts, installation, and travel that it may be cost effective to replace an engine instead of overhauling it, if a replacement engine is available with an acceptable delivery time frame. Hydro will choose whether to replace or overhaul based on which option is the least-cost alternative for each engine.

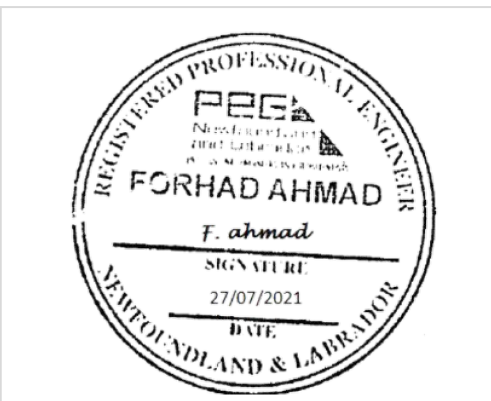
Appendix A

Genset Model Overhaul List – Three-Year Forecast

Table A-1: Genset Overhaul List – Three-Year Forecast

Unit	Forecast Year of Overhaul
2022	
Nain 2085	2022
Paradise River 585	2022
Rigolet 2081	2022
Rigolet 2101	2022
Mary's Harbour 2090	2022
Norman's Bay 581	2022
Grey River 2067	2022
2023	
Hopedale 2054	2023
Paradise River 324	2023
Rigolet 2065	2023
St. Lewis 2080	2023
2024	
McCallum 2064	2024
Postville 2084	2024
Charlottetown 2089	2024
Mary's Harbour 2093	2024
Port Hope Simpson 2100	2024

Tab 14: Purchase 46' Material Handler Aerial Device on Track Unit



2022 Capital Budget Application

Purchase 46’ Material Handler Aerial Device on Track Unit

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Purchase 46’ Material Handler Aerial Device on Track Unit

Category:	Transmission and Rural Operations – Tools and Equipment
Definition:	Other
Classification:	Normal
Investment Classification:	General Plant

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) uses aerial devices wherever possible to efficiently perform maintenance and upgrade work on its distribution and transmission assets. Hydro must have access to functional and reliable equipment to safely and efficiently maintain its system.

To replace equipment which is due for retirement, Hydro plans to purchase new equipment that will increase work efficiency and its application of live line techniques. Since implementing its Live Line Program in 2018, more than 250,000 customer outage hours have been avoided with the use of live line techniques.

Hydro does not have an off-road track unit with a 46’ Category B aerial device. Hydro currently has two 65’ aerial devices on larger track units but, due to their physical size, these units cannot always be used in areas with restricted right-of-way access, common in distribution applications. This project proposes the purchase of a 46’ Category B aerial device on an off-road track machine with power line technician bucket, jib, and winch to perform work on Hydro’s assets which cannot be reached with on-road equipment.

The estimated cost is approximately $758,000 and the project is scheduled for completion in 2024.

Contents

1.0 Introduction

Hydro uses aerial devices wherever possible to efficiently perform maintenance and upgrade work on its distribution and transmission assets. With some existing off-road equipment due for replacement, Hydro plans to purchase new equipment with improved off-road capabilities. This will allow Hydro to work more efficiently and increase its application of live line techniques in remote areas. Since implementing its Live Line Program in 2018, more than 250,000 customer outage hours have been avoided as a result of the use of live line techniques.

2.0 Background

Hydro maintains a fleet of off-road track equipment to perform work in off-road locations; some of this equipment is due to be replaced. With the addition of a 46' Category B[1] aerial device track unit, Hydro plans to retire two existing units—a 2000 Bombardier track muskeg with a knuckle boom and a 2008 Powertraxx. The new unit has better maneuverability, allowing Hydro to work more efficiently in off-road locations to minimize customer outages.

2.1 Existing System

Hydro does not have an off-road track unit with a 46' Category B aerial device. Hydro currently has two 65' aerial devices on larger track units but, due to their physical size, these units cannot always be used in areas with restricted right-of-way access, common in distribution applications.

2.2 Operating Experience

The existing fleet of equipment used for off-road work is not always effective for completing live line work, particularly in remote locations. The proposed equipment will improve work efficiency and the application of Hydro's Live Line Program in off-road areas and reduce customer impacts.

3.0 Justification

Performing work with aerial devices is safe and efficient and reduces customer impacts. However, in off-road locations, work sites cannot always be accessed with an aerial device. Hydro is proposing to retire

[1] American National Standards Institute ANSI/A92.2 Category B.

two units that are due for replacement and replace with a 46’ material handler aerial device which has greater off-road capabilities and features that will increase work efficiency.

4.0 Analysis

4.1 Identification of Alternatives

- Alternative 1: Deferral; and
- Alternative 2: Purchase 46’ material handler aerial device on track unit.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

To maintain system reliability and effectively respond to system issues, Hydro must maintain a reliable fleet of equipment. Deferring the planned retirement of equipment that has reached the end of its service life is not an acceptable alternative. The unit chosen to replace the two retire units will provide improved access to off-road work sites and increased application of efficient live line techniques.

4.2.2 Alternative 2: Purchase 46’ Material Handler Aerial Device on Track Unit

Under this alternative, Hydro will retire the two units which are due for retirement and replace them with a 46’ Category B aerial device on an off-road track machine with power line technician bucket, jib, and winch.

4.3 Proposed Alternative

Hydro proposes to purchase a 46’ Category B insulated device on track unit. It has features which make it possible for Hydro to complete live line work in remote locations, reducing customer outages.

5.0 Project Description

This project proposes the purchase of a 46’ Category B insulated device on track unit.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	580.0	0.0	**580.0**
Labour	18.2	14.9	4.7	**37.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	1.3	45.2	33.9	**80.4**
Contingency	0.9	58.7	0.2	**59.8**
Total	**20.4**	**698.8**	**38.8**	**758.0**

The anticipated project schedule is presented in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Project setup, develop scope statement, etc.	January 2022	February 2022
Technical Specifications:		
Develop technical specifications	March 2022	March 2022
Procurement:		
Tender and award	March 2022	April 2022
Delivery:		
Have new unit delivered to operating group	October 2023	November 2023
Close Out:		
Project completion certificate and lessons learned	January 2024	March 2024

6.0 Conclusion

Since implementing a Live Line Program in 2018, Hydro has realized significant benefits in work efficiency and reduced customer impacts. The purchase of an off-road track unit with a 46' Category B aerial device will replace two existing units and allow Hydro better access to off-road work sites and increased application of efficient live line techniques.

Tab 15: Replace Metering System

LICENSED PROFESSIONAL ENGINEER
09621
JOSHUA MANUEL
Joshua Manuel
SIGNATURE
07/28/2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Replace Metering System

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Replace Metering System

Category: Transmission and Rural Operations – Metering

Definition: Other

Classification: Justifiable

Investment Classification: Service Enhancements

Executive Summary

Metering is a core function of Newfoundland and Labrador Hydro's ("Hydro") service obligation. Accurate metering of electricity usage is necessary to provide quality service to customers. Hydro currently has three separate metering systems in place. These include manually-read meters and two versions of automated metering infrastructure ("AMI") meters the TS1 and PLX systems, which utilize power line carrier ("PLC") technology to enable data retrieval.

The TS1 metering system is currently at the end of its useful life and must be replaced. The system is no longer supported by the vendor and the increased inability to communicate with the meters is contributing to an increase in manual meter reading costs. Meters which utilize PLC technology for data retrieval are no longer being developed by metering manufacturers as they are switching to other communication means that provide increased communication capacity with less expensive equipment requirements. Therefore, Hydro has decided not to choose a PLC solution to replace TS1. Hydro believes this is also the appropriate time to propose a transition away from the use of manual meter reading in determining customer's demand and energy usage.

Hydro is proposing to transition to the use of a drive-by automatic meter reading ("AMR") system which uses a vehicle-mounted radio in data collection. This is the same meter reading approach used by Newfoundland Power. This project will replace all manually-read meters and TS1 meters. However, since the PLX solution is still working reasonably well and is still supported by the manufacturer, Hydro plans to monitor its performance in determining when to discontinue the use of PLX meters. Hydro believes this two-staged approach in transitioning away from PLC technology reflects its least-cost obligation in providing service.

The full transition to an automated meter reading approach will contribute to a safer work environment for Hydro's meter readers. Implementation of a modern metering solution will enable cost savings through greater efficiency in meter reading and the reduction of administration effort required to manage meter reading and the correction of billing errors. The proposed drive-by AMR system has been proven to be reliable through its use by Newfoundland Power and the drive-by AMR system costs are materially less than the AMI systems available.

Safety is a key factor contributing to Hydro's decision to transition away from the use of manually-read meters. The use of AMR technology in general can: reduce the total driving time required to read meters, eliminate the need for a meter reader to exit their vehicle to obtain a reading, reduce the total time spent walking on customers' property being exposed to weather elements, eliminate the difficulty in gaining access to elevated and indoor meters, and materially reduce the risk of animal attacks, all of which provide the opportunity for safer working conditions and reduced safety-related incidents.

This project will be completed over three years with metering equipment tender development and award in 2022 and meter installation and system integration in 2023 and 2024. The estimated cost of the proposed solution is $5,375,800.

Implementing the proposed drive-by AMR system will provide reliable service to customers at the lowest possible cost and contribute to a safer work environment for Hydro's meter readers.

Contents

1.0 Introduction

Metering is a core function of Hydro's service obligation. Hydro provides electrical service to approximately 39,000 customers[1] which are supplied through an electricity meter for which Hydro is responsible for determining customer usage on a monthly basis. Approximately 91% of the meters are energy-only meters and the remaining 9% record cumulative energy usage and the maximum monthly demand.

Each year, Hydro's capital budget provides for expenditures to purchase and install electrical demand and energy meters. Capital expenditures are driven by connecting new customers to the electrical system, federal regulations governing revenue meters, and improving safety and productivity.

Hydro employs the use of AMI[2] (49% of meters) and manual meter reading (51% of meters) in collecting customer usage data. There are two types of AMI used by Hydro, the TS1 (29% of meters) and PLX systems (20% of meters), both of which utilize PLC to enable data retrieval. Meters which utilize PLC technology for data retrieval are no longer being developed by metering manufacturers as they are switching to other communication means that provide increased communication capacity with less expensive equipment requirements.

The TS1 metering system is currently at its end-of-life and must be replaced. The system is no longer supported by the vendor and the increased inability to communicate with the meters is contributing to an increase in manual meter-reading costs. Hydro believes this is also the appropriate time to propose a transition from the use of manual meter reading in determining customer's demand and energy usage.

Hydro is proposing to transition to the use of a drive-by AMR system which uses a vehicle mounted radio in data collection. This is the same meter-reading approach used by Newfoundland Power. This project will replace all manually-read meters and TS1 meters. However, since the PLX solution is still working reasonably well and is still supported by the manufacturer, Hydro plans to monitor its performance in determining when to discontinue the use of PLC and propose replacement of the approximate 7,800 PLX meters. Hydro believes this two-staged approach balances its obligation to provide reliable service in metering customers while also giving consideration to the project cost.

[1] Excludes street and area lighting.
[2] AMI systems allow for real-time communication with the meter which gives the ability to send commands to the meter and to retrieve information rapidly.

2.0 Background

2.1 Existing System

Hydro's current metering system is comprised of three different types of meters, as follows:

1) Manually read meters;
2) Landis+Gyr AMR TS1 system; and
3) Landis+Gyr AMR PLX system.

Manually-read meters require meter readers to read directly from the meter and manually record the reading information either through a handheld unit or on paper. Hydro's manually-read meter system consists of 17,095 energy-only meters and 2,548 meters that record energy and demand.

The TS1 system that utilizes PLC communications is currently at its end-of-life. Hydro's TS1 system consists of 10,845 energy meters and 580 meters that record energy and demand. In 2014, the vendor announced it would be discontinuing support for the TS1 metering system and Hydro stopped purchasing TS1 meters at that time. Hydro has approximately 1,900 TS1 meters in service with which it cannot communicate and must read manually. Hydro has also replaced approximately 800 TS1 meters with meters that must be manually read. The continued use of the TS1 system is contributing to high operating costs as a result of meter troubleshooting, increased manual meter reading, and the increased requirement to bill customers based on estimated readings, leading to increased calls from customers and the requirement to regularly make billing adjustments.

The PLX system was partially implemented as the replacement for the TS1 system in 2016; PLX also uses PLC technology. It is still supported by the manufacture, although it is decreasing in relevance as utilities move away from PLC technology for meter reading. Hydro's PLX system consists of 7,557 energy-only meters and 253 meters that record demand and energy. Approximately three quarters of the PLX meters are on the Labrador Interconnected System. Due to the use of PLC technology and high purchase cost, there is a risk of obsolescence.

2.2 Replacement System

The TS1 meters have been at their end-of-life since 2014 and are also currently underperforming in many areas. The TS1 meter underperformance has been caused by communication issues leading to meters having to be manually read or estimated. While Hydro has not yet experienced material problems with the PLX system, PLC systems are no longer being developed by metering manufacturers as they are switching to other communication means that provide increased communication capacity with less and more inexpensive equipment. As a result, Hydro has decided not to choose a PLC solution to replace TS1.

The continued use of manual meter reading by Hydro creates concerns with respect to billing accuracy and meter reader safety. The use of manual meter reading also contributes to high operating costs and creates billing accuracy concerns for customers. In 2020, Hydro estimated approximately 60,000 monthly bills and was required to reissue cancelled and corrected bills to more than 800 customers.

Newfoundland Power currently utilizes a drive-by meter reading system for its service area. Hydro partnered with Newfoundland Power in testing the drive-by system over the past winter and was satisfied with its performance. Customers that participated in the pilot project experienced improved service through reduced billing estimates and the reduced requirement for billing adjustments to correct over or under billing. The use of the drive-by AMR system saved time in data retrieval and reduced the risk of injury to meter readers in performing their duties. The pilot project also gave Hydro the opportunity to become familiar with the functionality of the system.

To comply with Hydro’s obligation to accurately bill customers, Hydro believes it is appropriate to replace all TS1 meters and all meters that require manual reading with a drive-by AMR system. The PLX system is not at end-of-life and is still supported by the manufacturer. Hydro will continue to monitor the performance of the PLX system to determine when it would be optimal to fully transition from the use of PLC data retrieval.

3.0 Justification

This project is required to replace the obsolete TS1 system as well as the current manually-read meters with a reading technology that does not require manual entry. The full transition to an AMR approach will contribute to a safer work environment for Hydro’s meter readers. Implementation of a modern metering solution will enable cost savings through greater efficiency in meter reading, and the reduction of administration effort required to manage meter reading and the correction of billing errors. The proposed drive-by AMR system has proven to be reliable through its use by Newfoundland Power. Additionally, the drive-by AMR system costs materially less than the AMI systems available.

While the proposed AMR system does not enable the billing of time-of-use ("TOU") rates, a recent review conducted by Dunsky Energy Consulting[3] concluded that the Island system benefits of TOU pricing could not justify the additional cost of a full implementation of an AMI system at this time.

Implementing the proposed drive-by AMR system will provide reliable service to customers at the lowest possible cost.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Deferral;
- Continued use of manually-read meters;
- Installation of AMI system; and
- Installation of AMR drive-by system.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Deferral is not a reasonable alternative as the TS1 meters are currently obsolete and require replacement. If Hydro does not replace the TM1 system, Hydro will not be meeting its obligation to accurately bill customers on a monthly basis.

4.2.2 Alternative 2: Continue Use of Manually-Read Meters

Under this approach, the TS1 meters would be replaced with manually-read meters. Manual meter reading and data entry introduces a greater risk of errors in the readings and also results in a greater volume of estimated readings due to meter inaccessibility at different times of the year. Estimated readings are based on historical usage for customers that lead to over/under billing, customer inquiries, and billing adjustments which, in turn, has a negative impact on Hydro's customer relations. Replacing the TS1 meters with the manual meters will exacerbate Hydro's current metering issues.

[3] "Conservation Potential Study – Final Report (Volume 1 – Results)," Dunsky Energy Consulting submitted as Attachment A to Newfoundland Power's response to PUB-NP-104 in relation to the *Rate Mitigation Options and Impacts Reference* proceeding.

Increasing the number of meters to be manually read will increase Hydro's operating costs, further increases customer billing accuracy concerns, and increase safety concerns for meter readers.

4.2.3 Alternative 3: Installation of AMI System

Under this approach, Hydro would install metering technology that uses mesh radio networks to transmit readings from meters to centralized collection points. However, the up-front costs of an AMI mesh system are significantly higher than other metering solutions considered to address Hydro's current metering issues. As previously noted, a recent review conducted by Dunsky Energy Consulting concluded that the Island system benefits of TOU pricing could not justify the additional cost of a full implementation of an AMI system at this time.

4.2.4 Alternative 4: Installation of AMR Drive-By System

Under this approach, Hydro would install meters with built-in radios to transmit meter readings remotely to replace TS1 meters and meters that are manually read. Meter readers would be equipped with a tablet or handheld unit that is paired with a radio to read meters as they drive through their respective routes. Hydro would continue to maintain the PLX system and monitor its performance to determine when to propose to complete the transition from the use of PLC technology in data retrieval. This alternative is the least-cost option to address Hydro's current metering issues.[4]

4.3 Proposed Alternative

The proposed alternative for the metering system replacement is the replacement of the TS1 system and the manually-read meter system with an AMR drive-by system.

Hydro completed a cost-benefit analysis for the three alternatives described above. This analysis is summarized in Table 1.

Table 1: Alternative Comparison

Alternatives	Cumulative Net Present Value (to the year 2022) ($)	Difference in Cumulative Net Present Value and Least-Cost Alternative ($)
Alternative 2: Continue with Manually-Read Meters	20,298,727	8,570,010
Alternative 3: Mesh AMI System	16,322,023	4,593,306
Alternative 4: AMR Drive-By System	11,728,717	-

[4] As the PLX system is working reasonably well and is also an AMR system, there would be minimal savings associated with replacing the PLX system at this time.

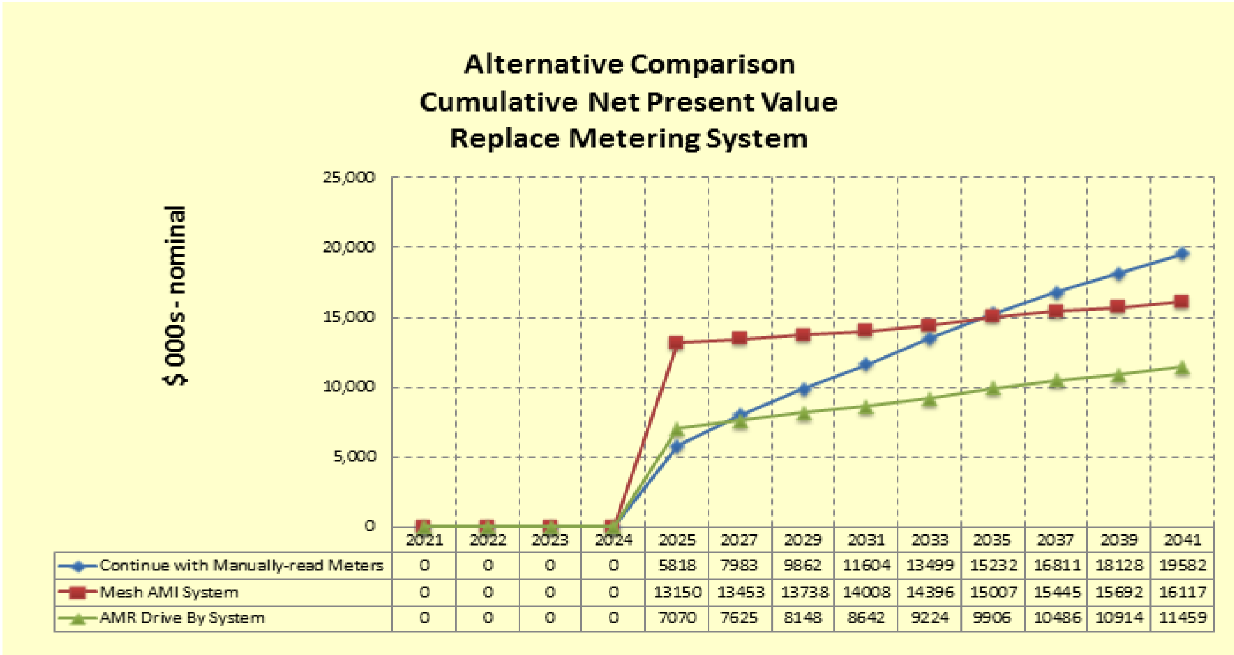


Figure 1: Alternative Comparison

5.0 Project Description

This project will replace Hydro's current manually-read meters and TS1 meters with a drive-by AMR system. The project scope will consist of the following:

- Replacement of existing meters with the appropriate type of replacement meter as follows:[5]
  - 28,056 energy-only meters; and
  - 3,131 demand and energy meters;
- Purchase of meter reading equipment that will be required to read the meters, including tablets, radios, and handhelds;
- Purchase of the required software for the operation of this new system;
- Installation of all purchased meters and radios; and
- Installation and integration of the software into Hydro's billing infrastructure.

[5] There are also a relatively small number of under-performing PLX meters to be replaced under this project (i.e., 116 energy-only meters and 3 demand and energy meters).

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	324.5	2,522.8	47.0	**2,894.3**
Labour	138.7	672.3	532.4	**1,343.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	189.9	111.4	**301.3**
Interest and Escalation	29.4	311.3	269.2	**609.9**
Contingency	23.0	169.3	34.6	**226.9**
Total	**515.6**	**3,865.6**	**994.6**	**5,375.8**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Develop project scope statement and schedule and conduct risk review	January 2022	February 2022
Design:		
Complete detailed engineering design	February 2022	June 2022
Procurement:		
Tender and award metering equipment	July 2022	September 2022
Construction:		
Complete site installation works	January 2023	November 2024
Commissioning:		
Final inspection and acceptance	October 2024	December 2024
Close Out:		
Interest cut-off, as-build drawings, and project close out	December 2024	December 2024

6.0 Conclusion

The need for reliable metering is essential to Hydro’s business and customer relationships. This project is required to replace obsolete TS1 meters and to replace manually-read meters with a reading technology that does not require manual reading and data entry. Installation of an AMR drive-by system in combination with maintaining the PLX metering system is the least-cost alternative to address the TS1 obsolescence as well as to improve the safety of meter readers, improve billing accuracy and to provide quality metering service and billing service to customers using the least-cost option.

Tab 16: Additions for Load – Distribution System

LICENSED PROFESSIONAL ENGINEER
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July 28, 2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Additions for Load (2022) – Distribution System – Mary's Harbour Voltage Conversion

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Additions for Load (2022) – Distribution System – Mary’s Harbour Voltage Conversion

Category:	Transmission and Rural Operations - Distribution
Definition:	Clustered
Classification:	Normal
Investment Classification:	System Growth

Executive Summary

The Mary’s Harbour distribution system is comprised of a single 4.16 kV distribution line or feeder that connects customers to the diesel generating station. This feeder serves the coastal Labrador towns of Mary’s Harbour and Lodge Bay.

Recently, Newfoundland and Labrador Hydro (“Hydro”) received a service request that substantially increased Hydro’s load forecast for this isolated system. This increase in load has caused violations of Hydro’s Distribution Planning Criteria. Further deferral of this project will result in an increased risk of damage to customer equipment or customer equipment malfunction.

Hydro performed an analysis of numerous alternatives to address the criteria violations including reconductoring, installation of a new bank of voltage regulators, voltage conversion, and advancing the time frame for interconnection with other southern Labrador communities. Hydro completed an economic evaluation for each of these options and determined that converting the voltage of the Mary’s Harbour distribution system from 4.16 kV to 25 kV is the least-cost alternative.

The estimated cost of this project is $1,075,200 and project completion is planned for September 2023.

Contents

List of Attachments

1.0 Introduction

Hydro provides electrical service to residents in select rural communities within the province through the use of electrical distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that directs power from the substation to customers throughout the community.

As new customers are added to distribution systems and existing customers use more electrical power, both the peak demand and energy requirements of communities grow. At times, to support additional peak demand and energy requirements, Hydro must upgrade and add new infrastructure to ensure the continued supply of reliable power.

The electrical infrastructure in Mary's Harbour consists of a diesel generating station coupled with a substation and distribution system that together supply electricity to both Mary's Harbour and Lodge Bay. Mary's Harbour is located in southern Labrador, as shown in Figure 1.

Figure 1: Labrador Electrical System

In September 2019, Hydro received a preliminary service request for a new large customer in Mary's Harbour. This request was finalized in March 2020 and indicates that the facility is expected to be in operation during the summer of 2021. The facility will have a peak demand of 507 kW during the summer and a non-summer peak load of 192 kW.

Based on load flow analysis, this additional load will cause a portion of the Mary's Harbour distribution system to experience voltages that violate Hydro's Distribution Planning Criteria, provided in Attachment 1, during the summer of 2021. Voltage levels at the end the distribution line servicing the area of expected growth will be lower than Hydro's normal low voltage limit but above Hydro extreme low voltage planning criteria. Although the system cannot remain in this condition for the long term, Hydro determined that the violation was not severe enough to deny service until the system was upgraded. Hydro has undertaken the analysis and determined that voltage conversion of the Mary's Harbour distribution system operating voltage from 4.16 kV to 25 kV is the least-cost option.

2.0 Background

2.1 Existing System

The Mary's Harbour distribution system is comprised of a single 4.16 kV distribution line, also known as a feeder, which connects customers to the diesel generating station. This feeder serves the coastal Labrador towns of Mary's Harbour and Lodge Bay. Mary's Harbour has population of approximately 340 residents[1] and the town of Lodge Bay has approximately 70 residents.[2] The primary and neutral conductors of the Mary's Harbour system mainly consist of 1/0 AASC.[3] The source of power for the Mary's Harbour distribution system is the Mary's Harbour Diesel Generation Station and the St. Mary's River Energy[4] Mini-Hydro plant.[5] The layout of the distribution system, including the location of the diesel plant and expected area of load growth, can be seen in Figure 2.

[1] 2016 Census data retrieved from Newfoundland and Labrador Community accounts.
[2] "Our Communities," Southern Labrador <http://www.southernlabrador.ca/home/communities.htm>.
[3] Aluminum alloy stranded conductor.
[4] St. Mary's River Energy is an independent power producer that sells energy to Hydro under a power purchase agreement.
[5] In 2021, Hydro expects to commission the St. Mary's River Energy Photo-Voltaic and Battery Energy Storage System which will then be added to the supply mix.

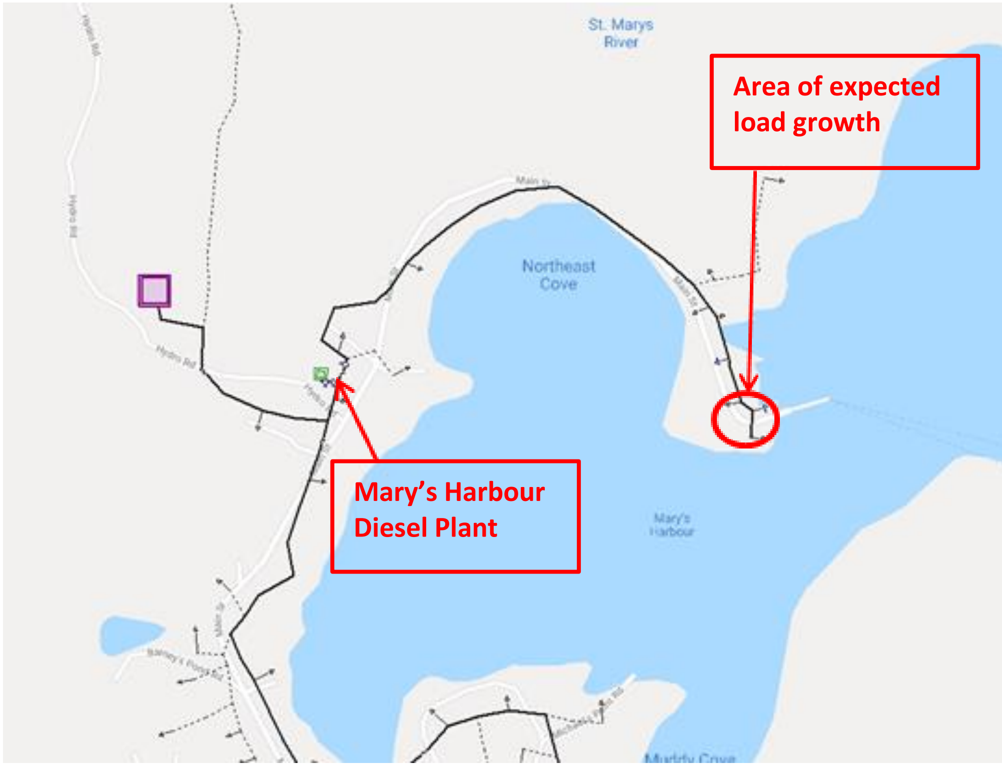

Figure 2: Layout of Mary's Harbour Distribution System

2.2 Operating Experience

The Mary's Harbour system is a summer peaking system that has been experiencing consistent load levels over the past seven years since the opening of a large fish plant in 2013. Since then, the energy requirement has slightly decreased year-over-year, while the peak load remains consistent. The peak load and energy consumption of the Mary's Harbour system from 2010 to 2020 is shown in Figure 3.[6]

[6] Values in Figure 3 are the system's gross peak loads recorded at the diesel generating station and include the power used by the station service load in addition to the community load.

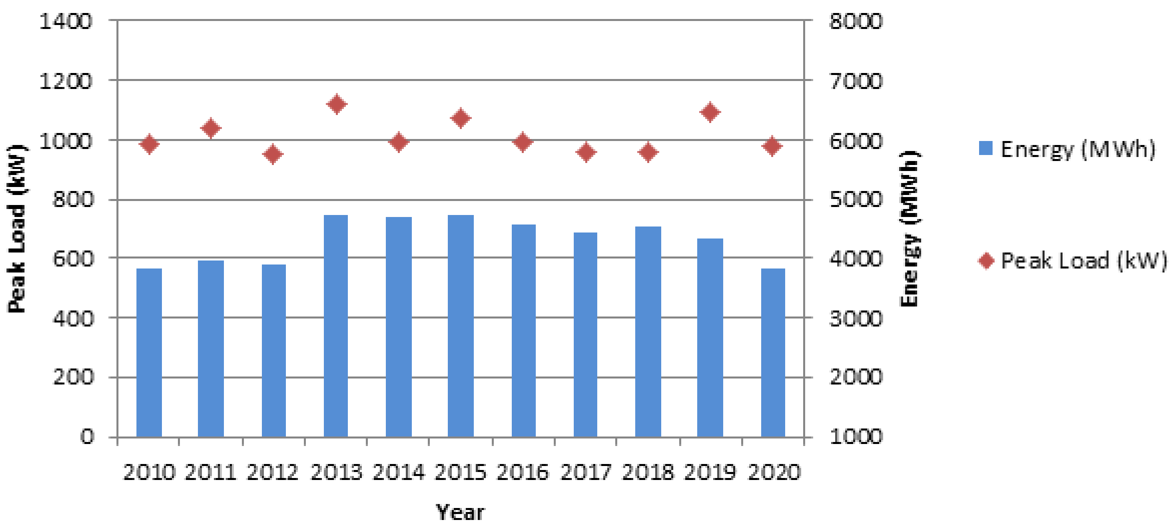

Figure 3: Mary's Harbour Historical Load

Hydro prepares forecasts of the anticipated loads on all of Hydro's distribution and isolated generation systems on an annual basis. These forecasts project the peak demands for each system and are used to determine the required amount of capacity that a distribution system or piece of equipment within the system must have to meet that demand. These yearly forecasts include the existing load on the system plus any expected load growth on the system. Table 1 shows the original spring 2020 Mary's Harbour forecast. Table 2 shows the revised spring 2020 forecast which includes the impact of the new service request.

Table 1: Spring 2020 Base Case Mary's Harbour Forecast[7]

	2021	2022	2023	2024	2025
Gross MWh	4,618	4,629	4,641	4,653	4,665
Gross Peak kW (Summer)	1,041	1,044	1,046	1,049	1,052
Gross Peak kW (Winter)	883	885	887	889	892

[7] Base case does not include the new cod plant.

Table 2: Spring 2020 Base Case Mary's Harbour Forecast – Cod Plant Included[8,9]

	2021	2022	2023	2024	2025
Gross MWh	5,213	5,464	5,476	5,488	5,500
Gross Peak kW (Summer)	1,167	1,177	1,180	1,182	1,185
Gross Peak kW (Winter)	994	1,006	1,008	1,010	1,013

3.0 Justification

This project is required to reliably meet the electricity needs of Hydro's customers on the Mary's Harbour distribution system. Hydro has completed a study of the Mary's Harbour distribution system to analyze the impact of unexpected load growth on the distribution system. The study has indicated that voltage levels at the end the distribution line servicing the area of expected growth are lower than Hydro's normal low voltage limit, but are above Hydro extreme low voltage planning criteria. When voltages are identified as within this range, plans must be made to resolve the low voltage issue, but delaying customer connection is not required in this case.

4.0 Analysis

4.1 Identification of Alternatives

Whenever distribution planning criteria violations are forecasted to occur on a distribution system, Hydro investigates various technical options to prevent the violations from occurring.

Hydro considered the following alternatives to address low voltages on the St. Mary's distribution system:

- Alternative 1: Deferral;
- Alternative 2: Upgrade distribution feeder from #1/0 AASC primary and neutral to a larger #4/0 AASC primary and #1/0 AASC neutral;
- Alternative 3: Upgrade distribution feeder from #1/0 AASC primary and neutral to a larger #477 ASC primary and #4/0 AASC neutral;
- Alternative 4: Install a set of voltage regulators;

[8] Hydro requested a detailed monthly consumption from the customer which has been reflected in this forecast.
[9] The amount of energy and capacity requested by the new customer is reflected in the forecast; however, the change in peak demand requirement does not equal the previous forecast plus the incremental capacity required by the new customer due to the customer's load factors and its contribution to system peak.

- Alternative 5: Advance the proposed voltage conversion of Mary's Harbour from 2030 to 2023; and
- Alternative 6: Advance the proposed interconnection of the Mary's Harbour distribution system to the proposed southern Labrador interconnected system from 2030 to 2024 and continue operation under normal low voltage conditions.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

Hydro will be in violation of its distribution planning criteria during the summers of 2021, 2022, and 2023. Although the low voltage violations are within the normal operating conditions and do not exceed Hydro's extreme operating conditions, it is not appropriate for Hydro to permit the low voltage violations to persist in the long term. Further deferral of this project will result in an increased risk of damage to customer equipment, or customer equipment malfunction.

4.2.2 Alternative 2: Reconductor with #4/0 Overhead Conductors

This alternative involves replacing 1,000 m of the feeder trunk which is currently comprised of a 1/0 AASC primary and neutral with a larger 4/0 AASC primary and 1/0 AASC neutral. The reconductoring will begin at the diesel generating station and continue along Main Street Road and end at the fish plants. A map of this alternative is shown in Figure 4. The capital cost to reconductor 1,000 m of three-phase distribution line is $312,300. This alternative will reduce electrical losses on the system which will save approximately $16,000 worth of fuel each year.

4.2.3 Alternative 3: Reconductor with 477 ASC Overhead Conductors

This alternative involves replacing 1,000 m of the feeder trunk which is currently comprised of a 1/0 AASC primary and neutral with a larger 477 ASC[10] primary and 4/0 AASC neutral. The reconductoring will begin at the diesel generating station and continue along Main Street Road and end at the fish plants. A map of this alternative is shown in Figure 4. The capital cost to reconductor 1,000 m of three-phase distribution line is $354,000. This alternative will reduce electrical losses on the system which will save approximately $24,700 worth of fuel each year.

[10] Aluminum-stranded conductor.

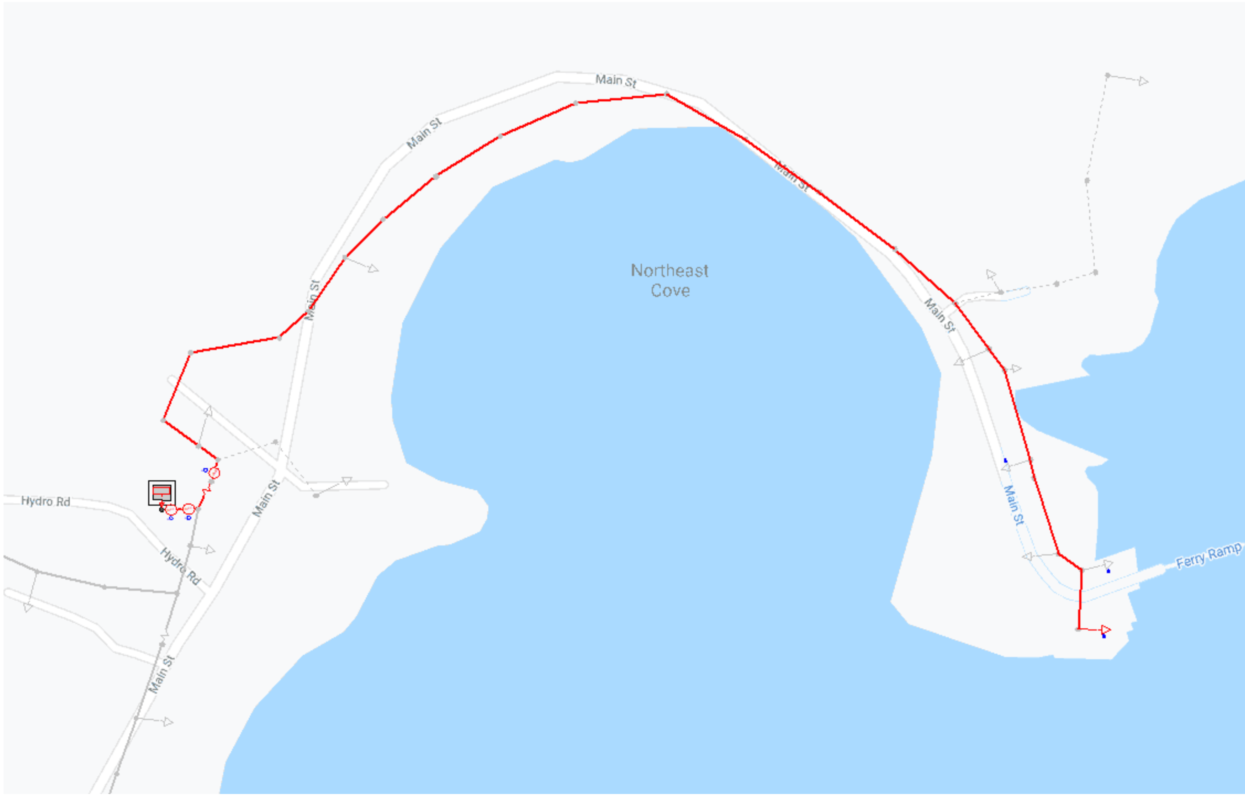

Figure 4: Section of Line to be Potentially Reconductored

4.2.4 Alternative 4: Install New Bank of 300 A Voltage Regulators

This alternative involves installing a bank of three 300 A voltage regulators in Mary's Harbour. The voltage regulators would be installed at or near the diesel generating station to ensure all customers receive regulated voltage. The capital cost to install three 300 A voltage regulators is $276,500. This alternative will not reduce electrical losses on the system.

4.2.5 Alternative 5: Voltage Conversion of Mary's Harbour Distribution System

This alternative involves converting the Mary's Harbour distribution system operating voltage from 4.16 kV to 25 kV. Voltage conversion of this line is required as part of phase 2 of Hydro's long-term supply plan for southern Labrador, which provides for interconnection of Mary's Harbour to Port Hope Simpson in 2030. Completing the project earlier alleviates the current voltage concerns and will also remove that portion of the 2030 scope.

Voltage conversion involves replacing all customer transformers on the system with dual voltage transformers. The initial capital cost to perform a voltage conversion in Mary's Harbour is approximately

$1,075,200. This alternative will reduce the electrical losses on the system which will save approximately $31,000 worth of fuel each year.

4.2.6 Alternative 6: Advance the Interconnection of Mary's Harbour to the Proposed Labrador South Interconnected System

This alternative involves advancing the proposed interconnection of Mary's Harbour to the proposed southern Labrador system from 2030 to 2024 and accepting the risk of low voltage during the peak seasons of 2022, 2023, and 2024. This alternative, however, was ruled out due to magnitude of costs associated with advancement of the planned interconnection of the Mary's Harbour system.[11]

4.3 Proposed Alternative

Based on the analysis of the six alternatives considered, Hydro performed a detailed cost-benefit analysis of the viable alternatives, comparing the two reconductoring alternatives, the voltage regulator alternative and the voltage conversion alternative. The economic evaluation included analyzing the capital costs required on the distribution system over a 20-year period as well as the fuel costs associated with electrical losses.[12] Hydro's analysis determined that voltage conversion of the Mary's Harbour distribution systems is the least-cost alternative and is therefore Hydro's proposed alternative.

Table 3 presents the CPW of the four economically viable alternatives and the difference in CPW between each alternative to determine which option is the least-cost alternative.

Table 3: Mary's Harbour Additions for Load Growth Cumulative Net Present Value to the Year 2021 ($)[13]

Alternatives	Cumulative Net Present Value ("CPW")	CPW Difference between Alternative and the Least-Cost Alternative
Voltage Conversion	1,148,253	
Re-conductor with 477 ASC	1,286,340	138,088
Re-conductor with #4/0 AASC	1,359,743	211,491
New Regulator – 300 A	1,543,265	395,013

[11] The estimated cost of interconnection of the Mary's Harbour system is $14.4 million.
[12] A 20-year study period was used to align with Hydro's long-term load forecast.
[13] Numbers may not add due to rounding.

5.0 Project Description

This project involves an upgrade in Mary's Harbour to address the load growth occurring in the community. The work being proposed in Mary's Harbour is to complete a voltage conversion of the distribution system supplying Marys' Harbour. This will include replacing all the customer distribution transformers and the Lodge Bay substation transformer. Table 4 shows the estimated cost for the project while Table 5 shows the schedule for the project.

Table 4: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	442.6	0.0	0.0	**442.6**
Labour	33.6	109.4	0.0	**143.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	279.6	0.0	**279.6**
Other Direct Costs	5.4	38.6	0.0	**44.0**
Interest and Escalation	20.8	54.3	0.0	**75.1**
Contingency	48.2	42.7	0.0	**90.9**
Total	**550.6**	**524.6**	**0.0**	**1,075.2**

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Start Date	End Date
Planning:		
Open job, develop project scope statement, and baseline schedule	January 2022	February 2022
Design:		
Detailed transmission and distribution design	January 2022	May 2022
Procurement:		
Procure materials	June 2022	Mar 2023
Construction:		
Voltage conversion	June 2023	July 2023
Commissioning:		
Acceptance inspection	June 2023	July 2023
Close Out:		
Project close out	August 2023	September 2023

6.0 Conclusion

System analysis indicates that the current distribution system in Mary's Harbour is experiencing voltage conditions that violate Hydro's distribution planning criteria due to a recent large service request.

An analysis of the Mary's Harbour distribution system has determined that the least-cost solution to accommodate the load growth is for Hydro to complete a voltage conversion of the distribution system at this time.

Attachment 1

Rural Planning Standard RP-S-003

Distribution Planning Criteria

RURAL PLANNING STANDARD

Distribution Planning Criteria

Doc # **RP-S-003**

Date: 2020/10/02

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 Purpose

Hydro's distribution planning criteria are established to ensure an adequate supply of power to customers served on Hydro's distribution systems. As a general rule to guide Hydro's planning activities the following criteria have been adopted.

2 Voltage Level Criteria

A) The range of normal operating voltage is based on the Canadian Standard CSA CAN3-C235-83 ("Preferred Voltage Levels…") and the CEA "Distribution Planner's Guide".

B) Voltage Unbalance – maximum 2% voltage unbalance.

C) Voltage Flicker Limit – maximum of 5% voltage flicker.

D) Temporary Overvoltage – maximum 110% overvoltage

2.1 Operating Voltage

Hydro uses the CSA standard *CAN3–C235–83 – Preferred Voltage Levels for AC Systems 0 – 50,000 V* as the guide for determining acceptable steady-state voltage limits at customers' service entrances. This is a National Standard of Canada that establishes a guideline for voltage standards for AC Systems in Canada. It was adopted by Hydro as its standard for the range of acceptable voltages that will be provided to customers and is used by utilities across Canada. A standard for voltage levels is necessary because the devices connected to the electrical system are designed to operate within a certain range of voltages. When voltages supplied to the device deviate from this acceptable range, the device can be damaged or fail to function properly. The standard is meant to ensure that the devices connected to the electrical system will receive voltage within their normal operating range so that they function normally and damage does not occur.

The standard refers to two separate operating conditions, normal and extreme. The normal operating condition is applied when the distribution system is operating as designed and not experiencing continuous operation outside design limits. The extreme operating condition is applied during continuous operation of a power system outside of design limits and planned capital or operating work is scheduled to be carried out to correct the issue. These conditions do not include voltages levels experienced during fault conditions or heavy starting loads.

Under normal operating conditions where there are no operational anomalies and the feeder is performing as designed, the customer service entrance voltage must be held between a minimum of 110 V for single-phase customers and 112 V for three-phase customers and a maximum of 125 V for a nominal 120 V service. Table 1 displays the normal and extreme operating condition nominal voltage ranges for many types of electrical services.

Table 1: Recommended Voltage Variation Limits for Circuits up to 1000V, at Service Entrances[1]

Nominal System Voltages	Voltage Variation Limits Applicable at Service Entrances			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single Phase (V)	**Lower Limit**		**Upper Limit**	
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three Phase 4-Conductor (V)				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/338	250/432	254/440
277/480Y	245/424	254/440	288/500	293/508
347/600Y	306/530	318/550	360/625	367/635
Three-Phase 3-Conductor (V)				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

The standard also states that primary service voltages are to be supplied within six percent of the nominal system voltage.

Under extreme operating conditions the distribution system is operating outside of the normal operating voltage limits and an operational anomaly has been identified on the system. In this case, work must be planned to correct the deficiency so that voltages remain within the normal operating condition limits. During extreme operating conditions, the customer service entrance nominal voltage must range from a minimum of 106 V for single-phase customers and 110 V for three-phase customers to a maximum of 127 V for a nominal 120 V service.

If the customer service entrance nominal voltage falls outside of the extreme voltage range as outlined in the CSA standard, emergency work must be completed as soon as possible to rectify the issue. If not, damage to customer equipment may occur. Hydro is responsible for ensuring voltage levels up to the service entrance, i.e. weatherhead, are within stated limits.

The above CSA standard has been adopted by Hydro to ensure customer service entrance voltages remain within the stated limits. However, planning engineers complete system design and analysis using nominal voltages on primary distribution feeders. To relate the two, the System Planning Department references the CEA Distribution Planners Manual. The manual provides estimates of the average voltage drop that

[1] From CSA standard CAN3–C235–83 (R2006) – Preferred Voltage Levels for AC Systems 0 – 50,000 V, Table 3 - Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances.

can be anticipated between the primary and the service entrance to define a minimum and maximum planning voltage on a 120 V base for the primary distribution line.

Table **2** and Table 3 outline the Hydro standard voltage drop for each line section and transformer between the primary conductor and the service entrance for single phase and three phase customers respectively.

Table 2: Preferred Voltage at the Primary for Single Phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage*		110	125
Voltage Drop at	Service Drop Wire	1	0.375
	Secondary Conductor	2	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		6	1.5
Voltage at Primary		116	126.5
Note: Some customers are supplied from express service drops. Therefore, no secondary voltage drop occurs under the light load condition. *** Hydro is responsible for voltage up to the service entrance.**			

Table 3: Preferred Voltage at the Primary for Three Phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage*		112	125
Voltage Drop at	Service Drop Wire	1	0.375
	Secondary Conductor	-	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		4	1.5
Voltage at Primary		116	126.5

Note: 3Φ General Service Customers are normally supplied from express drops off their own transformer bank. Therefore, no secondary voltage drop occurs.
*** Hydro is responsible for voltage up to the service entrance.**

Therefore, Hydro uses a planning voltage range of 116 V to 126.5 V on distribution primary lines, assuming a 120 V base.

2.2 Voltage Unbalance

Voltage unbalance occurs when loads are not equally distributed across all three phases of a distribution feeder. The percentage voltage unbalance is calculated as the maximum phase voltage deviation from the average voltage, divided by the average voltage, multiplied by 100%. It is common on many Hydro distribution systems to have long single phase lines with large end of line loads which can increase voltage unbalance. A feeder experiencing a high percentage of voltage unbalance can cause excessive motor heating, increasing the likelihood of failure.

2.3 Voltage Flicker

Voltage flicker is a transient phenomenon that occurs when large loads are switched on the system causing an instantaneous change in voltage. Usually this is experienced during motor starting or pick-up of a large customer load. In these cases, a dip in voltage is experienced due to the increase in current flow, causing lights to flicker. This can dim lighting and interrupt motor operation. Hydro will allow a maximum of 5% voltage flicker before work must be initiated to correct the problem. If voltage flicker worsens, the problem becomes much more noticeable and pronounced. Hydro addresses flicker at the operational level by setting limitations on the amount of current the system can supply to a customer without causing disturbances to other customers on the system.

2.4 Temporary Overvoltage

Temporary overvoltage is an increase in ac voltage greater than 1.1 pu for a duration longer than 1 min. Overvoltages can be the result of load switching (e.g., switching off a large load) or of variations in the reactive compensation on the system (e.g., switching on a capacitor bank). Poor system voltage regulation capabilities or controls can cause overvoltages.

3 Equipment Loading

Increases in customer load on distribution feeders can lead to overloading of overhead conductor and/or related equipment. A detailed load flow analysis will indicate areas which are experiencing current overloads during peak load conditions. Equipment affected by overloads includes transformers, circuit breakers, reclosers, voltage regulators and switches.

Equipment loading shall be no greater that 100% of its planning rating. These ratings indicated the maximum peak load permitted on a system component during normal operating conditions. It is recognised that under emergency or abnormal operating conditions, such as after recovering from extended outages, system components may be operated above the planning ampacity.

One abnormal operating conditions that is of particular importance when planning distribution systems is Cold Load Pick-Up (CLPU). CLPU is the amount of electricity that customers demand as they are re-energized after being without electrical service for an extended period of time. This is a function of the profile of customers/loads connected to a feeder. Generally, feeders with a high penetration of electric heating have the highest CLPU factors. The CLPU factor is defined as the CLPU divided by the normal winter peak load. If the maximum CLPU on a feeder is unknown, then the CLPU factor is assumed to be 2.0 and the duration is assumed to be 1.0 hour.

To manage CLPU on distribution system, utilities divide distribution feeder into sections so that not all load has to be picked up at the one time. This allows utilities to defer the substantial costs of upgrading s distribution system. However, doing this decreases the reliability of the system in terms of the System Average Interruption Duration Index (SAIDI) because customers are subjected to longer outages. For this reason only two designated sections may be permitted per feeder. These sections are separated by a sectionalizing switch that shall be located such that it maximized the planning ampacity for the system.

The optimum location for a sectionalizing switch is at the point where 66.67% of the load is on the first portion of the feeder and 33.33% of the load is on the second section of the feeder. Under this situation when recovering from an extended outage, when the first section of the feeder in energized the CLPU will be 133.3% (66.67% x 2) of the full feeder peak load. After this load settles the load on the first section will be back to 66.67% of the feeder peak load. When the second section of the feeder in energized, the load on the second feeder will be 66.67% of peak load (33.33% x 2) and the total feeder load will be 133.3% of peak load (66.67% first section + 66.67% second section).

To include CLPU and sectionalizing into Hydro's planning ratings the following formula is used.

- Planning Factor = Sectionalizing Factor * CLPU Factor

Where:

- CLPU Factor = CLPU load/winter peak load, (assumed as 2.0 unless system specific data is available)
- Sectionalizing Factor = amount of load in first section of feeder, (assumed to be 66.67% of feeder load unless physical constraints prevent this)

As a result the Planning Factor will range between 1.33 and 2.0, indicating a temporary loading between 133% and 200% of normal peak load when recovering from a CLPU event.

Planning ratings are determined based on Equipment Rating and Planning Factor which vary depending on the equipment being studied. Below is a summary on how Planning Ratings are calculated:

A) Transformers and Voltage Regulators: Planning Rating = 100% of name plate rating
B) Overhead Bare Conductor: Planning Rating = Winter Ampacity / Planning Factor
C) Reclosers: Planning Rating = Overload Capability/Planning Factor

3.1 Transformers and Voltage Regulators

The thermal limits of distribution step down transformers, and voltage regulators are based on IEEE – C57.91-1981. This standard shows the amount of load a transformer can withstand without affecting its service life. Although the amount of load on these transformer varies by transformer type, it is necessary to plan based on the worst case scenario so only the lowest overload capability will be utilized.

The planning ampacity for distribution transformers will depend on the configuration of the substation:

- In a distribution substation, the planning rating of the transformer will be 100% of the 30º C nameplate rating. By restricting the system peak load to the name plate rating, a 175% overload capability[2] provides capacity to restore a distribution system after an extended outage where CLPU is present.
- The planning ampacity for diesel plant substation transformer is provided in *RP-S-002 Rural Isolated Systems Generation Planning Criteria*

As stated above, CLPU on a particular distribution system may range from 133% of peak load to 200% of peak load depending on the sectionalizing ability of the distribution system. For distribution systems that contain one distribution feeder and where the CLPU exceeds 175% of the normal winter peak load, a sectionalizing switch may be required on the feeder to limit CLPU. Where substations contain two or more feeders and a CLPU potential greater than 175% of the name plate rating exists, in addition to sectionalizing, feeders may need to be restored on a sequential basis to limit CLPU.

[2] The 175% overload capability is based on a 25% loading bonus due ambient temperatures and a 50% loading bonus due to the equivalent load before a CLPU peak load.

3.2 Conductors

Overloads on bare overhead conductor are identified during load flow analysis for the particular distribution feeder. Hydro has adopted the IEEE738[3] method for calculating the continuous ampacity of overhead conductor based on ambient temperatures. Table 4 below shows the continuous and planning ampacities for Hydro's most commonly used aerial conductors.

Table 4: Conductor Planning Ratings

Size and Type	Cont. Labrador Winter Ampacity	Cont. Island Winter Ampacity	Planning Ampacities Planning Factor = 2.0		Planning Ampacities Planning Factor = 1.33	
			Lab Winter Ampacity	Island Winter Ampacity	Lab Winter Ampacity	Island Winter Ampacity
#4 Copper	226	196	113	98	170	147
#2 ACSR	244	213	122	107	183	160
1/0 AASC	358	317	179	159	269	238
2/0 AASC	412	365	206	183	309	274
2/0 ASCR	389	345	195	173	292	259
4/0 AASC	557	493	279	247	418	370
477 ASC	904	800	452	400	678	600

These ampacities indicate the maximum allowable amperage on an aerial conductor under any circumstance during winter. These calculations are based on the assumptions found in Hydro's Distribution Planning Assumptions Standard.

3.3 Reclosers

The planning rating for reclosers is based on the overload capability of the recloser. This overload capability varies by model type and manufacturer. For example, most of Hydro's reclosers are cooper VWVE reclosers. These reclosers have an overload capability of 150% for a maximum of 2 hours. Therefore the planning rating for reclosers will be overload capability of the recloser divided by the planning factor of the feeder. For the Cooper VWVE reclosers this will be 646 A.

3.4 Switches

Hydro has two standard types of switches, group operated switches and single-phase cutouts. Group operated switches are rated for load breaking and are operated by a single handle to break all phases at the same time. These switches do not use any fuses for line protection. Single-phase cutouts are used

[3] IEEE738 - IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors

for isolating sections of line once they have been de-energized, as they are not rated to break load. Cutouts, however, can be fused to a number of ratings depending on the protection requirements. For planning and analysis purposes, the System Planning Department uses 100% of the continuous current rating for switches. Gang switches are rated for 600A per phase, where solid blade (no fuse) cutouts are rated for 300A. If the cutout is fused, the rating then becomes the rating of the installed fuse.

3.5 Circuit Breakers

The planning rating for circuit breakers is based on the IEEE std C37.010-1979. This standard provides the overload capabilities of circuit breakers for ambient temperatures less than the 40 deg name plate rating.

3.6 Load Imbalance

Load imbalance occurs when customer loads are not equally distributed across all three phases of a distribution feeder. The percentage of load imbalance is calculated as the maximum phase load deviation from the average load, divided by the average load, multiplied by 100%. A highly unbalanced load on a feeder can lead to a high degree of voltage unbalance along the feeder due to varying voltage drop on the phase conductors. An unbalanced feeder will experience higher losses due to currents flowing in the neutral circuit.

Document Summary

Document Owner:	Rural Planning
Document Distribution:	Rural Planning

Revision History

Revision	Prepared by	Reason for change	Effective Date
1.0	Scott Henderson	Criteria added to DMS	2020/10/02
2.0	Scott Henderson	Modified transformer loading criteria to reflect 46kV transfer to TP	2020/10/02

Document Approvers

Position	Signature	Approval Date
Team lead, Rural Planning	Scott Henderson	2020/10/02

Document Control

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Tab 17: Install Fire Protection in Diesel Plants

2022 Capital Budget Application

Install Fire Protection in Diesel Plants (2022–2023) – Ramea

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Install Fire Protection in Diesel Plants (2022–2023) – Ramea

Category:	Transmission and Rural Operations – Generation
Definition:	Other
Classification:	Normal
Investment Classification:	Service Enhancement

Executive Summary

Most of the diesel generating stations owned and operated by Newfoundland and Labrador Hydro ("Hydro") are located in remote coastal areas of Newfoundland and Labrador and are not staffed 24 hours per day. There have been fires at several of these diesel generating stations, resulting in the loss of equipment and facilities, as recently as 2019 in Charlottetown, Labrador.

When these diesel generating stations were constructed, they were not fitted with automatic fire suppression systems. After experiencing a number of fires that caused large-scale station damage and unplanned power outages, Hydro started a program in 2014 to install automatic fire suppression systems. To date, six installations have been completed.

This project will install an automatic fire suppression system in the Ramea Diesel Generating Station. Engineering will start in 2022 for installation in 2023.

The estimated budget of this project is $1,928,800.

Contents

1.0 Introduction

Hydro currently owns and operates 23 diesel generating stations in different areas and communities of Newfoundland and Labrador. Hydro’s diesel generating stations are the only source of electric power in communities that are isolated from the interconnected electrical grid.

There have been serious fires at these diesel generating stations, resulting in the loss of equipment and facilities, as recently as 2019 in Charlottetown, Labrador. Starting in 2014, Hydro initiated a multi-year program to install automatic fire suppression systems in its diesel generating stations. To date, suppression systems have been installed in the Hopedale, L'Anse Au Loup, Cartwright, Nain, Postville, and Makkovik Diesel Generating Stations. As a continuation of the multi-year program, this project will install an automatic fire suppression system in the Ramea Diesel Generating Station which is shown in Figure 1 and Figure 2.

Figure 1: Ramea Diesel Generating Station

Figure 2: Ramea Diesel Generating Units

2.0 Background

The fire suppression systems installed since 2014 are automatic systems[1] that utilize an inert clean gas (nitrogen) and water stored in pressurized cylinders. In event of a fire, these systems spray a mix of nitrogen with very small water droplets. The nitrogen extinguishes the fire by displacing oxygen; water absorbs the heat from the fire with minimal wetting of the diesel generating station.

2.1 Existing System

The Ramea Diesel Generating Station is equipped with a fire detection system that consists of heat detectors, manual pull stations, fire alarm annunciation control panels, audible alarms, and auto dialers. The diesel generating station is not staffed 24 hours per day and does not have an automatic fire suppression system. If a fire is detected, an alarm will activate and the auto dialer will attempt to

[1] These automatic fire suppression systems were recommended for Hydro's diesel generating stations in a study completed in 2012 by Hatch Ltd., an engineering consulting firm.

contact the shift operator or Energy Control Centre in St. John's. In addition, the control panel, which interfaces with the diesel generating station's operating equipment, is activated to shut down all ventilation systems and online generators to reduce fire spread. The diesel generating station is also equipped with a number of portable fire extinguishers. If there is a fire, extinguishing it may be attempted by diesel generating station personnel if safe to undertake such action. There is a local volunteer fire department that can also respond.

2.2 Operating Experience

There have been fires at Hydro's diesel generating stations resulting in the loss of equipment and facilities. Significant total plant outages have been incurred along with reduced power supply for extended periods of time. Major fires in diesel generating stations include:

- Charlottetown on October 7, 2019, when the powerhouse was destroyed. A total power outage of 17 hours was incurred before temporary mobile generation could be provided at largely reduced capacity. Hydro does not intend to replace the Charlottetown Diesel Generating Station; rather, has proposed construction of Phase 1 of a long-term supply plan for southern Labrador, which includes the construction of a regional diesel generating station in Port Hope Simpson and interconnection with the existing Charlottetown distribution system by 2024.[2]
- Nain on September 7, 2008, which resulted in a total power outage of 35.5 hours and extensive damage to the diesel generating station. In addition, there was a second major power outage due to a fire at the Nain Diesel Generating Station on November 19, 2008. That power outage lasted 29.5 hours for 50% of customers and 52 hours for the remaining customers. The Nain rehabilitation project cost (2008–2011) was $2.58 million.
- Black Tickle on March 14, 2012, when the engine hall was extensively damaged resulting in a total power plant outage of 40 hours. The Black Tickle rehabilitation project cost (2012–2013) was $1.42 million.

3.0 Justification

The project is required to mitigate the potential damage to the powerhouse and generating assets at the Ramea Diesel Generating Station in the event of fire. Implementation of an automatic fire suppression

[2] "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021.

system will reduce the cost associated with repairing fire damage and also support the reliable provision of power to customers by reducing outage durations associated with fires.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Deferral of the fire suppression system installation; and
- Alternative 2: Installation of an automatic fire suppression system.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral of the Automatic Fire Suppression System Installation.

Considering the history of damage and outages resulting from fires in Hydro's diesel generating stations that have no automatic fire suppression systems, this alternative is not acceptable as it increases the risk of fire damage that could result in an extended outage and damage to the plant.

4.2.2 Alternative 2: Installation of an Automatic Fire Suppression System.

This alternative proposes the continuation of Hydro's program to install automatic fire suppression systems, which has been in place since 2014. Continuation of this program with installation at the Ramea Diesel Generating Station in 2022–2023 is an appropriate alternative to mitigate the reliability impact and potential damage to equipment in the event of fire.

4.3 Proposed Alternative

To mitigate the risk of extended customer outages and damage to the Ramea Diesel Generating Station in the event of fire, Hydro proposes to install an automatic fire suppression system in 2022–2023.

5.0 Project Description

The project will install an automatic hybrid nitrogen-water fire suppression system at the Ramea Diesel Generating Station. The scope of work includes design, procurement, installation, and commissioning of the new equipment. Engineering will start in 2022 for installation of the fire suppression system in 2023. The majority of the work will be completed by external contractors to supply and install the fire equipment with support from Hydro's internal engineering and labour personnel.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	0.0	10.0	0.0	**10.0**
Labour	28.1	79.4	0.0	**107.5**
Consultant	50.0	10.0	0.0	**60.0**
Contract Work	0.0	1,452.0	0.0	**1,452.0**
Other Direct Costs	0.0	4.5	0.0	**4.5**
Interest and Escalation	4.8	126.6	0.0	**131.4**
Contingency	7.8	155.6	0.0	**163.4**
Total	**90.7**	**1,838.1**	**0.0**	**1,928.8**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project (capital job cost)	January 2022	February 2022
Prepare scope statement and detailed schedule	February 2022	April 2022
Tendering:		
Issue request for proposals for conceptual design, evaluate proposals, and award contract	May 2022	September 2022
Prepare and issue tender package for detailed design, supply, and installation; evaluate bids; and award contract	August 2022	December 2022
Design:		
Prepare conceptual design for fire suppression system	September 2022	October 2022
Prepare detailed design and shop drawings for fire suppression equipment	January 2023	March 2023
Procurement:		
Supply fire protection equipment	April 2023	July 2023
Installation:		
Install fire suppression system	July 2023	September 2023
Commissioning:		
Perform testing and commissioning of fire suppression system	September 2023	September 2023
Close Out:		
Prepare close out documents	October 2023	December 2023

6.0 Conclusion

The Ramea Diesel Generating Station has no automatic fire suppression system to permit early intervention in the event of a fire. This project is a continuation of Hydro's multi-year fire suppression program for its diesel generating stations which will minimize the damage and customer outage duration resulting from a fire by installing an automatic fire suppression system in the Ramea Diesel Generating Station.

Tab 18: Upgrade Circuit Breakers

LICENSED PROFESSIONAL ENGINEER
08547
Jared Hawco
J Hawco
SIGNATURE
7/29/2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Upgrade Circuit Breakers (2022–2023) – Various

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Upgrade Circuit Breakers (2022–2023) – Various

Category:	Transmission and Rural Operations – Terminal Stations
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

Executive Summary

This proposal is for the refurbishment and replacement of 46 kV, 66 kV, 138 kV, and 230 kV circuit breakers. The refurbishment and replacement of the identified circuit breakers is required to support system reliability and safety, and, in the case of the oil circuit breakers, compliance with federal environmental regulations related to removing polychlorinated biphenyls (“PCB”).[1]

The circuit breakers selected for refurbishment and replacement in 2022 and 2023 are part of Newfoundland and Labrador Hydro’s (“Hydro”) long-term asset management plan for circuit breaker replacement and refurbishment. The circuit breakers proposed for refurbishment and replacement in this project were identified using a similar methodology as that reflected in Hydro’s previous Upgrade Circuit Breakers project, which was approved by the Board of Commissioners of Public Utilities (“Board”) as part of Hydro’s 2021 Capital Budget Application.[2] Air blast breakers and oil circuit breakers will be replaced due to their age, condition, reliability concerns, and, in some instances, for compliance with federal environmental legislation. They will be replaced with sulphur hexafluoride (“SF_6”) circuit breakers. The SF_6 circuit breakers identified for refurbishment are approximately halfway through their existing useful life or have been identified as requiring refurbishment based on their condition.

In addition to the breakers identified for replacement or refurbishment based on condition, age, and environmental regulations, Hydro plans to replace five generator unit breakers at the Bay d’Espoir Hydroelectric Generating Station with breakers which are more suitable for a generator synchronization

[1] The *Canadian Environmental Protection Act* includes PCB Regulations (SOR/2008-273) which provide end-of-use dates for various concentrations of PCBs.
[2] “2021 Capital Budget Application,” Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. 2, tab 8. Approved in Board Order No. P.U. 2(2021).

application due to recent failures of the existing circuit breakers.[3] The replacement of the first three generator unit breakers are proposed herein.

As the replacements and refurbishments identified for completion in 2022 and 2023 are required for reliability and legislative compliance purposes, deferral of this work is not a viable alternative. The work outlined in this proposal is scheduled for completion by the end of 2023 and is expected to cost approximately $9,483,700.

[3] Existing circuit breakers would be relocated to other locations in the transmission system where they would not be subjected to synchronizing stresses.

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List of Attachments

1.0 Introduction

Circuit breakers are critical components of the power system. Located in terminal stations, circuit breakers perform switching actions which are necessary to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers is essential to protect and maintain the stability of the power system.

2.0 Background

2.1 Existing System

Hydro currently maintains three different types of circuit breakers, which operate at three voltage classes.[4] The three types of circuit breakers are as follows:

1) Air blast;
2) Oil; and
3) SF_6.

Each type of circuit breaker has unique operating characteristics. Air blast circuit breakers offer features such as fast response and automatic reclosing. They are widely used where repeated operation is essential. Unlike air blast circuit breakers, which uses air to extinguish the current arc created inside the circuit breaker, oil circuit breakers extinguish the arc using insulating oil. SF_6 circuit breakers are the newest design. They use SF_6 gas, which has very good dielectric properties, to extinguish electrical arcs created during switching. The utility industry is trending towards the use of SF_6 circuit breakers due to their availability and desirable operating characteristics of this technology.

Circuit breakers are comprised of two primary components:

1) An interrupting device, which includes the arc quenching medium; and
2) The insulating material and the operating mechanism.

Air blast circuit breakers, oil circuit breakers, and SF_6 circuit breakers are designed and constructed differently and, as such, refurbishment requirements vary for each type of circuit breaker. For air blast

[4] The three voltage classes of circuit breakers are 66/69 kV, 138 kV and 230 kV. 46 kV circuit breakers are in the same voltage class of equipment as 66/69 kV circuit breakers.

circuit breakers, both the interrupting device and operating mechanism require a mid-life refurbishment of seals, O-rings, and lubrication. The SF_6 circuit breakers typically require refurbishment at approximately 20 years (i.e., halfway through the expected useful life). Oil circuit breakers must be replaced rather than refurbished due to environmental legislation requiring removal of PCBs,[5] which are contained in the bushings of oil circuit breakers.

As of the end of 2020, Hydro had 9 air blast circuit breakers, 186 SF_6 breakers and 30 oil circuit breakers in its 46 kV and above circuit breaker fleet. Within the circuit breaker fleet, Hydro has 47 circuit breakers in service that range from 40 to 60 years of age. A number of the circuit breakers within Hydro's system have been operational for more than 30 years with a significant number nearing or already surpassed the expected useful life of such assets.[6] The probability of circuit breaker failure increases with age.

2.2 Operating Experience

Following the January 2014 power outages, Hydro developed a plan to accelerate the replacement of air blast circuit breakers.[7] The plan also indicated that overhauls of SF_6 circuit breakers will be completed at approximately 20 years and that they would be replaced at or near 40 years. In accordance with this plan, Hydro has updated its long-term plan for circuit breakers.

Hydro's long-term plan includes the replacement of air blast circuit breakers by the end of 2023 due to reliability issues, replacement of oil circuit breakers by the end of 2025 to ensure compliance with federal environmental legislation, the overhaul of SF_6 circuit breakers after 20 years of service, and the consideration of replacement of SF_6 circuit breakers after approximately 40 years of service, based on their condition at that time.

Between October 2018 and November 2019, Hydro experienced failure of four generator unit breakers at the Bay d'Espoir Terminal Station 1. Hydro undertook an analysis of the failures and assessed options for the replacement of the existing generator unit breakers at Bay d'Espoir with those more suitable for a generator synchronizing application. Hydro's assessment, a summary of which is provided in

[5] The *Canadian Environmental Protection Act* includes PCB Regulations (SOR/2008-273) which provide end-of-use dates for various concentrations of PCBs.
[6] Expected useful life is typically estimated to be 40 to 55 years, depending on the type of circuit breaker.
[7] Based on information obtained by Hydro following the system events in 2014, several other Canadian utilities are also replacing air blast circuit breakers with replacement scheduled for completion from 2015 to beyond 2020.

Attachment 1, determined that replacement of the existing dead tank circuit breakers with live tank circuit breakers is required to support reliable service in a synchronization application.

3.0 Justification

This project is required for Hydro to provide safe, reliable electrical service, and to comply with federal PCB regulations as follows:

- For reliability purposes, air blast circuit breakers are scheduled for replacement by 2023;
- To comply with federal PCB regulations, oil circuit breakers are scheduled for replacement prior to 2025;
- To optimize the useful life of its in-service SF_6 circuit breakers and ensure the appropriate balance between cost and reliability for customers, Hydro is refurbishing SF_6 circuit breakers after 20 years of service and replacing them at approximately 40 years of service, depending on the condition and operational history of the circuit breaker; and
- For reliability purposes, replacement of the existing SF_6 dead tank circuit breakers in generator synchronization applications at Bay d'Espoir with live tank circuit breakers is recommended.

4.0 Analysis

4.1 Identification of Alternatives

The following alternatives were considered:

- Alternative 1: Deferral; and
- Alternative 2: Proceed with refurbishments and replacements.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

The continued operation of the units identified for replacement or refurbishment without the required intervention increases the risk of failure and/or legislative non-compliance. Therefore, deferral of the proposed refurbishment and replacements is not a viable alternative.

4.2.2 Alternative 2: Proceed with Refurbishments and Replacements

The refurbishment and replacement of circuit breakers in a planned, strategic manner as outlined in this proposal is prudent. Such an approach enables Hydro to manage resource requirements and system outages in a way that supports its mandate to provide least-cost, reliable service.

4.3 Proposed Alternative

Hydro proposes the refurbishment and replacement of circuit breakers. This approach is consistent with the methodology and philosophy outlined in Hydro's Terminal Station Asset Management Overview.[8]

5.0 Project Description

This project includes the refurbishment and replacement of select 46 kV, 66/69 kV, 138 kV, and 230 kV circuit breakers. One replacement is planned for 2022, and six refurbishments, and eight replacements are planned for 2023.

Of the Bay d'Espoir breakers proposed for replacement, Hydro plans to replace one generator unit breaker in 2022, and two in 2023. The remaining two circuit breakers will be proposed for replacement in Hydro's 2023 Capital Budget Application. Further details regarding the replacement of circuit breakers at the Bay d'Espoir Terminal Station are provided in Attachment 1.

Table 1: 2022 Circuit Breakers Planned for Refurbishment or Replacement

2022 Refurbishments	2022 Replacements	Voltage
None	Bay d'Espoir B2T3	230 kV

Table 2: 2023 Circuit Breakers Planned for Refurbishment or Replacement

2023 Refurbishments	Voltage	2023 Replacements	Voltage
Deer Lake B1L39	138 kV	Buchans B1L28	230 kV
Deer Lake B1L45	138 kV	Buchans L28L32	230 kV
Howley B1L45	138 kV	Bay d'Espoir B1T1	230 kV
Peter's Barren B2L62	69 kV	Bay d'Espoir B3T5	230 kV
Roddickton Wood Chip B1L57	69 kV	Wabush Terminal Station B3T11 (46-12)	46 kV
St. Anthony Airport B1L61	69 kV	Wabush Terminal Station B3SS1 (46-16)	46 kV
		Wabush Terminal Station B3L4 (46-24)	46 kV
		Wabush Terminal Station B4T6 (46-6)	46 kV

[8] "2022 Capital Budget Application," Newfoundland and Labrador Hydro, August 2, 2021, vol. II, sch. 8, tab 10.

1 The estimate for this project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	1,218.0	564.0	0.0	**1,782.0**
Labour	354.9	1,292.1	0.0	**1,647.0**
Consultant	0.0	125.4	0.0	**125.4**
Contract Work	338.2	4,370.7	0.0	**4,708.9**
Other Direct Costs	28.3	202.1	0.0	**230.4**
Interest and Escalation	85.5	479.8	0.0	**565.3**
Contingency	97.0	327.7	0.0	**424.7**
Total	**2,121.9**	**7,361.8**	**0.0**	**9,483.7**

2 The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project, initial planning, and scheduling	January 2022	February 2022
Detailed Design (Year 1):		
Conduct site visits and complete detailed design	January 2022	March 2022
Procurement (Year 1):		
Order breakers	January 2022	August 2022
Tender and award contract(s) for breaker replacement	March 2022	May 2022
Construction/Commissioning (Year 1):		
Breaker replacement	August 2022	September 2022
Detailed Design (Year 2):		
Conduct site visits	October 2022	November 2022
Complete detailed design	November 2022	February 2023
Procurement (Year 2):		
Tender and award contract(s) for overhauls	February 2023	April 2023
Tender and award contract(s) for breaker replacements	February 2023	April 2023
Construction/Commissioning (Year 2):		
Breaker replacements and overhauls	April 2023	October 2023
Close Out:		
Project completion and close out	November 2023	December 2023

3 6.0 Conclusion

4 This project is for the replacement of one circuit breaker in 2022, and six refurbishments, and eight
5 replacements in 2023. The refurbishment and replacement of the identified circuit breakers is required

to ensure system reliability, safety, and compliance with federal environmental regulations. Completing this refurbishment as proposed in a planned and measured way reduces the risk of in-service failure of the circuit breakers and is consistent with the methodology and philosophy outlined in Hydro’s Terminal Station Asset Management Overview.

Attachment 1

Bay d'Espoir Terminal Station Generator Unit Breaker Report

Bay d'Espoir Terminal Station

Generator Unit Breaker Report

July 2021

A report to the Board of Commissioners of Public Utilities

Executive Summary

This report summarizes Newfoundland and Labrador Hydro's ("Hydro") review of the options to replace five 245 kV dead tank circuit breakers at the Bay d'Espoir Terminal Station 1, as recommended in Hydro's February 14, 2020 report, entitled "Bay d'Espoir Terminal Station General Electric Dead Tank Circuit Breaker Failure Report."[1]

Hydro compared the use of a dead tank circuit breaker design versus a live tank design in a synchronizing application, considering the experiences of other utilities and recommendations from manufacturers. The use of circuit breakers for high-voltage generator synchronization is an application that presents numerous challenges. During high-voltage generator synchronization, breakers are exposed to higher voltage stresses as well as out-of-phase conditions and arcing for extended periods of time.

Three out of the four General Electric ("GE") dead tank unit breaker failures experienced by Hydro at Bay d'Espoir Terminal Station 1 can be attributed to particle-related issues leading to internal flashovers. On this basis, Hydro is recommending replacement of the dead tank generator breakers for Units 1, 3, 4, 5, and 6 with live tank breakers and external current transformers. Live tank breakers have superior flashover performance due to the nature of their design and are not known to experience particle-related failures.

The risk of failure of the GE dead tank unit breakers at Bay d'Espoir Terminal Station 1 is higher than other locations in the Island Interconnected System and Hydro plans to redeploy the existing breakers in transmission applications where the risk of failure is lower.

Replacement of the Bay d'Espoir unit breakers will be included as part of Hydro's 2022 and 2023 Capital Budget Applications, with a plan to start replacing breakers in 2022. Hydro plans to replace one breaker and associated current transformers in 2022, two in 2023, and two in 2024. Hydro anticipates that the total project cost to replace the Bay d'Espoir generator unit breakers for Units 1, 3, 4, 5, and 6 is approximately $4.1 million.

[1] "Bay d'Espoir Terminal Station General Electric Dead Tank Circuit Breaker Failure Report," Newfoundland and Labrador Hydro, February 14, 2020, filed as part of the "2019–2020 Winter Readiness Planning Report – Further Update."

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List of Appendices

1.0 Introduction

On February 14, 2020, Hydro submitted a report to the Board of Commissioners of Public Utilities entitled "Bay d'Espoir Terminal Station General Electric Dead Tank Circuit Breaker Failure Report." Within this report, Hydro provided the details of failures that occurred between October 2018 and November 2019 on four relatively new GE DT1-245P F3 dead tank circuit breakers. All four failures occurred at Bay d'Espoir Terminal Station 1. The breakers involved in three of the four failures were shown to have quality issues from the factory which were likely aggravated by other factors to the point of failure. These other factors include impact forces during transportation to site, particle generation and high-voltage stresses from frequent operation of the breaker each time a unit is put online or taken offline, and high-voltage, high-frequency transients the breaker is exposed to each time the 245 kV unit disconnect switch is operated.

The "Bay d'Espoir Terminal Station General Electric Dead Tank Circuit Breaker Failure Report" recommended Hydro evaluate options to replace the five 245 kV dead tank GE circuit breakers at Bay d'Espoir with a circuit breaker that is better suited for generator application. This report provides an overview of the application of circuit breakers for high-voltage generator synchronization and circuit breaker technology currently available on the market, examines standard practice being used by manufacturers and other utilities, and makes recommendations for the replacement of the Bay d'Espoir unit breakers.

2.0 High-Voltage Generator Synchronization

At Bay d'Espoir Hydroelectric Generating Station, the generator circuit breaker is located on the high-voltage side of the generator step-up transformer; refer to the Bay d'Espoir Terminal Station 1 System Operating Diagram provided in Appendix A for further details. The use of circuit breakers for high-voltage generator synchronization is an application that presents many challenges.

One of the issues associated with the application of high-voltage circuit breakers for generator synchronization is that the breaker is exposed to higher voltage stresses and out-of-phase conditions for long durations. When bringing generation online, the bus side of the breaker is at system voltage level while the voltage on the generator side of the breaker is increasing, this creates a condition whereby phase and voltage differ across the breaker poles. The duration of the out-of-phase condition and increased voltage stress should be minimized as much as possible. While synchronizing with the system, the breaker can experience greater than 2.0 per-unit[2] system voltage across the open contacts. High-voltage withstand tests are performed on the 245 kV breakers in accordance with IEEE[3] Standard C37.09: Standard Test Procedures for AC High-Voltage Circuit Breakers at 425 kV, or ~3.0 per-unit system voltage across the circuit breaker for 60 seconds.

3.0 Circuit Breaker Technology

There are two main types of air insulated high-voltage circuit breakers currently available on the market: (1) dead tank breakers and (2) live tank breakers. The merits of each technology as it applies to high-voltage generator synchronization application are further described in the sections that follow.

3.1 Dead Tank Circuit Breakers

Dead tank circuit breakers have a metal-enclosed interrupter unit and the housing, or tank, is always grounded. Dead tank breakers are particularly useful in substation designs where space is limited due to their small footprint and phase spacing. Dead tank breakers offer particular advantages if the protection design requires the use of several current transformers per pole assembly. Due to the breaker tank being at ground potential, the breakers can be equipped with up to three bushing current transformers for measurement or protection purposes. The current transformers are mounted in weatherproof housings at the base of the bushings on both sides of each breaker pole and the current transformer leads terminate in the main control cabinet onto short-circuiting terminal blocks. Figure 1 shows a picture of a dead tank breaker installed at Bay d'Espoir Terminal Station 1.

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[2] Per unit: In power system analysis a per-unit system is the expression of system quantities as fractions of a defined base unit quantity.
[3] The Institute of Electrical and Electronics Engineers ("IEEE").

Figure 1: Dead Tank Circuit Breaker BDE B2T4

While there are advantages to dead tank circuit breakers, they can also present challenges. For example, dead tank breakers are prone to issues with gas leaks due to the high quantity of gas required for the insulation medium, high surface area of the tank, and porosity of the tank castings.

Due to the nature of their design, there is a constant voltage stress present between the grounded tank and live interrupter unit. This electrical stress can contribute to continuous solid insulation degradation over time making dead tank breakers more prone to line to ground flashovers. One of the four breaker failures experienced by Hydro at Bay d'Espoir Terminal Station 1 was due to a line to ground flashover. These issues can be further aggravated by the presence of particles inside the breaker tank created during the manufacturing and assembly process as well as during general operation of the breaker. During switching, transient voltages are present which can result in particles becoming excited and moving around inside the breaker tank from areas of low electrical stress to areas of high electrical stress, and can effectively reduce the voltage withstand of the insulation medium leading to internal flashovers. Dead tank breakers have particle traps built into the tank designed to encourage movement of particles into areas of low electrical stress where they will remain trapped and not be able to contribute to an internal flashover; however, depending on the size and location of the particles, the particles may not all end up or stay in the designed traps.

3.2 Live Tank Circuit Breakers

In contrast to dead tank circuit breakers, the interrupter unit and housing in live tank circuit breakers is not grounded and is exposed to high-voltage potential. Live tank breakers also require a larger foot print and higher phase spacing to maintain minimum electrical clearances between phases. This breaker design also prevents the use of bushing current transformers; therefore, external current transformers are required for protection and measurement, further increasing the footprint required for installation. Live tank breakers have a higher center of gravity which necessitates the use of larger concrete foundations for stability. Live tank breakers also require an external central control cabinet for termination of interphase cabling as well as power and control cabling. Figure 2 shows a live tank breaker installed at Hydro's Wabush Terminal Station.

Figure 2: Live Tank Circuit Breaker Wabush Terminal Station 230-2

Despite the physical space requirements needed for live tank breaker installations, they do offer a number of advantages over dead tank breakers. Live tank breakers require a much lower quantity of gas, about 15–20% of the volume required for a dead tank breaker. They have a materially smaller tank surface area and are therefore less prone to gas leaks. Due to the nature of their design with the interrupter unit and tank all at live potential, there is no possibility of experiencing arcing or line to ground flashovers between the interrupter and tank. Live tank breakers up to 245 kV have what is referred to as a "candle stick" design in that the tank and interrupter are positioned vertically. Due to the vertical nature of the tank, particle-related failures are rare since gravity causes particles to fall to the bottom of the tank to an area of low electrical stress. There are no known common failure modes for live tank breakers with manufacturers quoting very low failure rates for breakers in service.

4.0 Industry Standard Practice

Industry standard practice for the use of circuit breakers for high-voltage generator synchronization, including other utility experience with this application, is detailed in the sections that follow.

4.1 Other Utilities Experience

There is no industry standard for manufacturers to follow when designing and testing circuit breakers for use in high-voltage generator synchronization applications.

Hydro One has devised its own application solution when specifying high-voltage breakers for synchronizing duty to be installed at various nuclear power plants, utilizing a hybrid design with a higher voltage class interrupter to increase the voltage withstand capabilities across the open gap of the interrupter. For example, in a 250 kV application, Hydro One specifies a 362 kV interrupter unit inside the breaker tank, and for a 500 kV application an 800 kV interrupter is specified. This can also effectively be achieved by increasing the voltage class of the entire circuit breaker to the next highest rating to achieve higher nameplate ratings and open gap voltage withstand capabilities. For the Bay d'Espoir unit breakers, this would require specifying a 362 kV breaker for use in a 245 kV application; however, due to space constraints in the existing breaker bays at Bay d'Espoir Terminal Station 1, a 362 kV live tank breaker will not fit, as they have a "T" shape design with the tank and interrupters positioned horizontally.

Both BC Hydro and Manitoba Hydro use live tank breakers in high-voltage generator applications at 145 kV, 230 kV, and 550 kV. The decision to use live tank breakers over dead tank breakers was not based on the application but instead based on other factors including higher fault level ratings, superior cold weather performance, market availability, and cost effectiveness. Live tank breakers can achieve minimum temperature ratings of -50°C using mixed gas without requiring tank heaters. Both utilities have experienced multiple tank heater failures on dead tank breakers in cold weather environments;

however, neither utility has experienced breaker failures or major issues with the live tank breakers being used in a generator application.

4.2 Manufacturer's Recommendations

Hydro has been in contact with various manufacturers to gather recommendations as to how it should proceed with the Bay d'Espoir generator unit breaker replacements based on their expertise with the application of circuit breakers for high-voltage generator synchronization. Recommendations from GE, Siemens, and ABB are summarized below.

4.2.1 GE Recommendations

GE has recommended the live tank 245 kV GL314X circuit breaker for use as a generator unit breaker at Bay d'Espoir Terminal Station 1. Hydro currently has three of this model breaker installed at its Wabush Terminal Station in a transmission application since 2018 and has not experienced issues thus far. These breakers are also installed at the Churchill Falls Terminal Station and Soldier's Pond Terminal Station with no known issues to date. This model live tank breaker has been used in Churchill Falls since 2013 to synchronize all 11 generating units with the system with no breaker failures or major issues to date. This breaker can be specified to have increased ratings for basic impulse level to 1,200 kV and switching impulse level to 800 kV.

4.2.2 Siemens Recommendations

Siemens has recommended two different breaker models that would be suitable for use at Bay d'Espoir for generator synchronization: (1) the dead tank 3AP1-DT 362kV breaker and (2) the live tank 3AP2F1-420 kV breaker. Both breakers are rated for higher voltage classes than that of the application, which will provide increased nameplate ratings and provide superior voltage withstand across the open gap of the interrupter. The dead tank breaker proposed is suitable for generator synchronization duty with synchronizing times of up to five minutes. The live tank breaker has two breaking chambers and can be used without restrictions in regards to limiting arcing times experienced by the breaker, avoiding the occurrence of delayed zero crossings from fault currents.

4.2.3 ABB Recommendations

ABB has recommended the 245PMG63-B 245 kV dead tank breaker or the HPL300B1 300 kV live tank breaker for use as a generator unit breaker at the Bay d'Espoir Hydroelectric Generating Facility. The dead tank breaker has a continuous current rating of 5,000 A, a short-circuit current rating of 63 kA, and a basic impulse level rating of 1,050 kV. The live tank breaker is rated for a higher voltage class than the application and has a continuous current rating of 4,000 A, a short-circuit current rating of 40 kA, and a basic impulse level of 1,050 kV.

5.0 Hydro Recommendations

5.1 Bay d'Espoir Generator Unit Breaker Replacements

Hydro is recommending replacement of the five GE dead tank breakers for Units 1, 3, 4, 5, and 6 with live tank breakers and external current transformers. This recommendation is based on the following:

- Live tank breakers have superior flashover performance and are not known to experience particle-related failures. The failure mode for three of the four unit breaker failures was a flashover across the open gap of the interrupter, while the other failure mode was a flashover to ground between the interrupter and tank which is not possible for a live tank breaker. The root cause of three of the four failures was due to the presence of foreign particles inside the breaker tank or interrupter created during the manufacturing process. Particles can also be created during general operation of circuit breakers and, since the generator unit breakers are frequently operated, there is a higher risk of particle generation than in a transmission application.
- Positive experience of other utilities using live tank breakers in a high-voltage generator switching application.

For the above two reasons and Hydro's experience with both dead tank and live tank breakers, Hydro is of the opinion live tank breakers are more suitable for generator applications to reduce the risk of particle-related failures.

5.2 Live Tank Breaker Special Considerations

Live tank breakers require a larger footprint due to their high center of gravity, higher phase spacing, and requirement for external current transformers. The current GE dead tank breakers have a total of six current transformers, three on each side of the breaker. To maintain the same number of current transformers, Hydro would have to install external current transformers on both sides of the new live tank breakers. Space restrictions and existing utilities in the breaker bays do not provide the necessary space for the current transformer installation on both sides of the breaker. In light of this, Hydro assessed whether installation of only one set of external current transformers would be sufficient to maintain existing protections circuits. Based on this review, it was determined that installation of current transformers on only the bus side of the new live tank breakers would not compromise existing protections. Existing bus differential protection circuits utilize the current transformers on the generator side of the unit breakers; however, there are two spare current transformers available on each of the generator step-up transformers that can be used for bus differential protection circuits; therefore, live tank breakers with current transformers on only one side of the breaker can be installed.

5.3 Capacitive Voltage Transformer Replacements

In 2019, Hydro engaged Hatch Limited to complete a transient study at Bay d'Espoir Terminal Station 1. The findings of the study show that the switching of the high side disconnect switch can create high-frequency transient voltages over 700 kV. The magnitude of this transient is below the breaker basic impulse level rating of 1,050 kV, but still high enough to cause movement of particles inside the breaker. The particles could potentially move to an area of high electrical stress and reduce the voltage withstand of the circuit breaker, triggering an internal flashover. A recommendation from the transient study is to replace the capacitor voltage transformers at the buses connecting generation to the system with potential transformers. This will effectively reduce the capacitance ratio and reduce the magnitude of the transient created during opening of the disconnect switch. Based on this recommendation, Hydro is planning to replace the existing capacitor voltage transformers with potential transformers as part of the Terminal Station Refurbishment and Modernization Program proposed in its 2022 Capital Budget Application.[4]

5.4 Risk Assessments and Timing of Replacements

As part of its evaluation of the timing for replacement of the GE dead tank breakers, Hydro has completed a qualitative risk assessment and looked at both the probability of failure of a unit breaker at Bay d'Espoir Units 1, 3, 4, 5, and 6, and the impact of such a failure to the system and on adjacent equipment. This risk evaluation is explained below.

Hydro has evaluated the probability of failure of the Bay d'Espoir Units 1, 3, 4, 5, and 6 breakers and has assigned this as a very high probability. This is due to the following:

- There have been four failures from October 2018 to November 2019 and the existing breakers installed on Units 1, 3, 4, 5, and 6 are the same model and manufactured at the same factory.

[4] "2022 Capital Budget Application, Newfoundland and Labrador Hydro, August 2, 2021, vol. II, sch. 6, tab 10.

- Three of the four breakers that failed were shown to have quality issues which may be present in the unit breakers currently in service. Also, quality issues are compounded in a generator application due to the higher voltage stress experienced by the breaker during synchronization and transients from switching disconnects.
- The high number of operations of the unit breakers at the Bay d'Espoir Hydroelectric Generating Facility will generate more particles. Particles in the presence of higher voltage stresses imposed on these breakers each time a unit is put online or taken offline could trigger a failure.

Regarding the impact, when a breaker failure occurs at Bay d'Espoir Terminal Station 1, the fault is typically cleared by the adjacent bus breaker which effectively removes two units from service. This condition persists until the failed breaker is isolated and the adjacent unit is put back in service which can take up to several hours. This will leave two units (170 MVA) unavailable for several hours. If nothing else were to happen on the system, Hydro is prepared for the failure of a single unit breaker as it is within the loss of our largest unit criteria assuming it clears as expected.

However, if the combined impact from a system perspective is considered such as a compounding, unrelated failure (e.g., a penstock issue or frazil ice at another generating plant during peak conditions), the impact to the Island Interconnected System could be significantly greater.

Furthermore, from an equipment impact perspective, all 230 kV generator unit breaker failures are significant events that could potentially result in generator or transformer damage if not cleared by the protection quickly, which could result in high costs and a unit being unavailable for several months.

With the system impacts as noted and the potential equipment impacts, Hydro considers the overall impact of a generator breaker failure to be high. Combining this with a high probability of failure for the current GE dead tank breakers, Hydro has evaluated the overall risk to be high.

With the high risk associated with a generator breaker failure and coordination of unit outages for up to six weeks per breaker, Hydro is recommending the replacement of the unit breakers for Units 1, 3, 4, 5, and 6 starting in 2022.

Replacement of the Bay d'Espoir unit breakers will be included as part of Hydro's 2022 and 2023 Capital Budget Applications with a plan to start replacing breakers in 2022. The scope of the 2022 Capital Budget Application will include engineering design and procurement of new equipment for three units with installation of one breaker and associated current transformers in 2022 and two breakers and associated current transformers in 2023. Procurement and execution for replacement of the final two Bay d'Espoir Terminal Station 1 unit breakers and associated current transformers will be included as part of the 2023 Capital Budget Application. Hydro will also submit a proposal for the procurement of a live tank circuit breaker as a capital spare under the Terminal Station In-Service Failures project as part of the 2023 Capital Budget Application.

To help mitigate any failures until all at-risk unit breakers at Bay d'Espoir are replaced, which is expected to be in 2024, Hydro will:

- Continue to operate in a manner that keeps the high-voltage disconnects associated with the unit breakers closed to minimize transients and reduce the probability of failure;
- Utilize, if necessary, one of the three spare phases that were received from GE in the first quarter of 2020. This is expected to reduce the repair time to 2–3 days and minimize the impact to the system; and
- Utilize one of its direct replacement spare 245 kV breakers, if more than one phase were to fail. The previous failures were associated with only one phase on all four failures experienced, so Hydro believes a multi-phase failure is unlikely.

6.0 Project Schedule and Cost

6.1 Schedule

It is anticipated that replacement of the Bay d'Espoir unit breakers will take three years to complete. In 2022, Hydro expects to complete procurement of three new circuit breakers and detailed engineering design for the first unit breaker replacement. Hydro's proposed project, beginning in 2022, will include execution of the first unit breaker replacement as well as detailed engineering design for the next two unit breaker replacements. Hydro's subsequent project, beginning in 2023, will include execution of the next two unit breaker replacements as well as procurement and detailed engineering design for the final two unit breaker replacements. Beginning in 2024, it will include execution of the final two unit breaker replacement and project close out activities.

6.2 Cost Estimate

Hydro anticipates that the total project cost to replace the Bay d'Espoir generator unit breakers for Units 1, 3, 4, 5, and 6 is approximately $4.1 million.

7.0 Conclusion

The risk of failure for the GE dead tank unit circuit breakers is high due to the high frequency of operation and higher voltage stresses the breakers are exposed to when units are put online and taken offline. Hydro plans to replace the unit breakers at Bay d'Espoir Terminal Station 1 with new live tank breakers and external current transformers and use the breakers removed from service in a transmission application where the risk of failure is much lower. Replacement of the Bay d'Espoir Terminal Station 1 unit breakers will be included as part of the 2022 and 2023 Capital Budget Applications with a plan to start replacing breakers in 2022. Hydro plans to replace one breaker and associated current transformers in 2022, two in 2023, and two in 2024.

Appendix A

Bay d'Espoir Terminal Station 1 System Operating Diagram

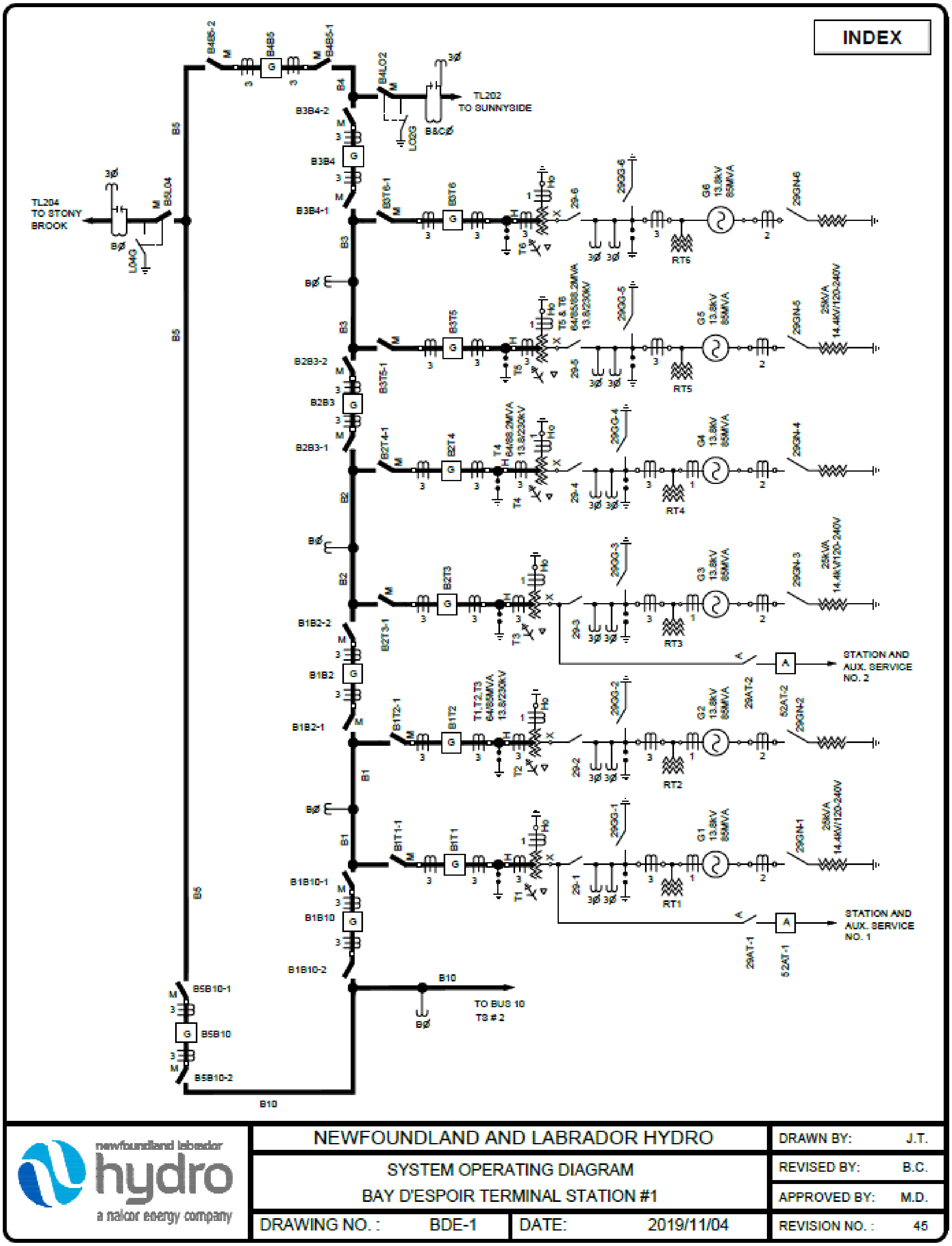

Figure A-1: Bay d'Espoir Terminal Station 1 Operating Diagram

Tab 19: Provide Service Extensions

2022 Capital Budget Application

Provide Service Extensions (2022) – Various

July 2021

A report to the Board of Commissioners of Public Utilities

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Provide Service Extensions (2022) – Various

Category: Transmission and Rural Operations – Distribution

Definition: Pooled

Classification: Normal

Investment Classification: Access

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") provides direct service to approximately 39,000 customers within its service areas. Hydro provides service hookups on an as-required basis using customer-driven service requests. This is a single-year project to provide an annual allotment for new service connections and street lights[1] based on past expenditures and forecasted activity within the regions.

2.0 Background

Hydro receives service requests for residential and general service, driven by local growth and activity within Hydro's three service regions: Central, Northern, and Labrador. Service requests can include residential developments, the addition of cabin developments, and new business developments. Each customer requires interconnection to the local distribution service system. Service requests are received by Hydro's Customer Service department and plans are developed by the local regions to provide the service extensions required to meet the service requests. In some cases, contributions in aid of construction ("CIAC") are required and are applied under Hydro's CIAC Policy.

Five-year historical expenditures under this annual project are provided in Table 1.

Table 1: Five-Year Historical Expenditures ($000)[2]

Region	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual
Central	1,842	1,531	1,103	1,075	1,127
Northern	1,498	1,623	1,220	1,037	1,060
Labrador	1,242	1,522	1,297	1,265	1,824
Total	**4,582**	**4,675**	**3,620**	**3,377**	**4,012**

[1] New street lights installed will be light-emitting diode ("LED") technology.
[2] Numbers may not add due to rounding.

3.0 Project Justification

In recent years, Hydro has seen an overall decline in the requirement for service extensions on the distribution system, as reflected in the actual expenditures from 2016 to 2020 shown in Table 1. The proposed project estimate, as provided in Table 2, is based on an analysis of the historical expenditures within the past five years for the provision of service extensions by region, supplemented with regional planning input regarding anticipated future activity levels. The project estimate by region is shown in Table 3.

While Hydro will plan the work under this project as efficiently as possible, Hydro is obligated to provide the requested services and deferral is not an option.

4.0 Project Description

This is a single-year project to provide an annual allotment for new service connections and street lights, based on past expenditures and forecasted activity within the regions.

Table 2: Project Estimate ($000)[3]

Project Cost	2022	2023	Beyond	Total
Material Supply	1,027.0	0.0	0.0	**1,027.0**
Labour	1,681.0	0.0	0.0	**1,681.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	376.0	0.0	0.0	**376.0**
Other Direct Costs	372.0	0.0	0.0	**372.0**
Interest and Escalation	171.2	0.0	0.0	**171.2**
Contingency	0.0	0.0	0.0	**0.0**
Total	**3,627.2**	**0.0**	**0.0**	**3,627.2**

Table 3: Estimate for 2022 Service Extensions ($000)

Region	Budget
Central	1,094.3
Northern	1,090.3
Labrador	1,442.6
Total	**3,627.2**

[3] Includes an estimated $200,000 to be recovered through CIAC.

5.0 Conclusion

Hydro provides service hookups on an as-required basis using customer-driven service requests in its service areas. This project is an annual allotment, adjusted from year to year depending on historical expenditures, for Hydro's connection of new residential and general service requests.

Tab 20: Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights

2022 Capital Budget Application

Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2022) – Various

July 2021

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Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2022) – Various

Category:	Transmission and Rural Operations – Distribution
Definition:	Pooled
Classification:	Normal
Investment Classification:	Renewal

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") provides direct service to approximately 39,000 customers within its service area. The distribution system serving these customers requires normal upgrading of individual structures and equipment, including street lights, on an as-required basis to correct issues identified as a result of operational field inspections or storm damage. This is an annual single-year project that provides a budget allotment based on past expenditures within the regions to address in-service failures of distribution equipment, required localized upgrades due to service deficiencies, and small-scale replacements due to storm damage.

Hydro is also proposing to continue the street light modernization program it commenced in 2021 in the scope of this project as the replacement of the remaining mercury vapor ("MV") and high pressure sodium ("HPS") street lights in Hydro's distribution system with light-emitting diode ("LED") street lights will be completed as part of Hydro's routine street light replacement work; such work falls under the scope of distribution in-service failures and miscellaneous upgrades. Hydro has determined that the most cost-effective method of transitioning its existing street lights to LED street lights is to replace them during required visits as opposed to repairing or replacing the existing MV or HPS street light more immediately. Hydro expects it will take approximately five years to convert the remaining MV and HPS street lights on the Island Interconnected System using this approach.

2.0 Background

2.1 Distribution System

Hydro maintains its distribution system through regular preventive maintenance inspections. As a result of these inspections, defects are identified and individual replacements of structures or equipment are sometimes required. In addition, storm damage can also necessitate replacement of distribution infrastructure.

Five-year historical expenditures under this annual project are provided in Table 1. Based on historical expenditures, Hydro forecasts an anticipated project estimate for the following year. In some cases, contributions in aid of construction ("CIAC") are required and are applied under Hydro's CIAC Policy.

Table 1: Five-Year Historical Expenditures ($000)

Region	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual
Central	1,877	1,671	1,706	2,015	1,502
Northern	993	924	1,079	716	1,214
Labrador	709	610	420	649	573
Total	**3,579**	**3,205**	**3,205**	**3,380**	**3,289**

2.2 Street Lights

Hydro's distribution system includes approximately 7,700 street lights. To date, Hydro has converted all isolated diesel communities to LED technology and is in the process of converting to LED technology on interconnected systems. The conversions have yielded positive results (e.g., lower maintenance requirements, greater energy efficiency, enhanced reliability, and quality of lighting).

3.0 Project Justification

Hydro's historical expenditures related to in-service failures and upgrades on the distribution system have been relatively consistent as reflected in the 2016–2020 actual expenditures shown in Table 1. Deferral of this project is not viable as a certain level of expenditure is required annually to address failed equipment and service deficiencies to maintain reliable service to customers.

The capital investment to modernize street lights is justified based on the long-term cost savings and reliability benefits to customers. Hydro's proposal to replace MV and HPS street lights with LED street lights is consistent with Newfoundland Power's plan to transition to LED street lights and will result in reduced street and area light rates to Hydro's customers. Figure 1 provides the cumulated estimated costs of LED street lights compared to HPS street lights over 20 years.

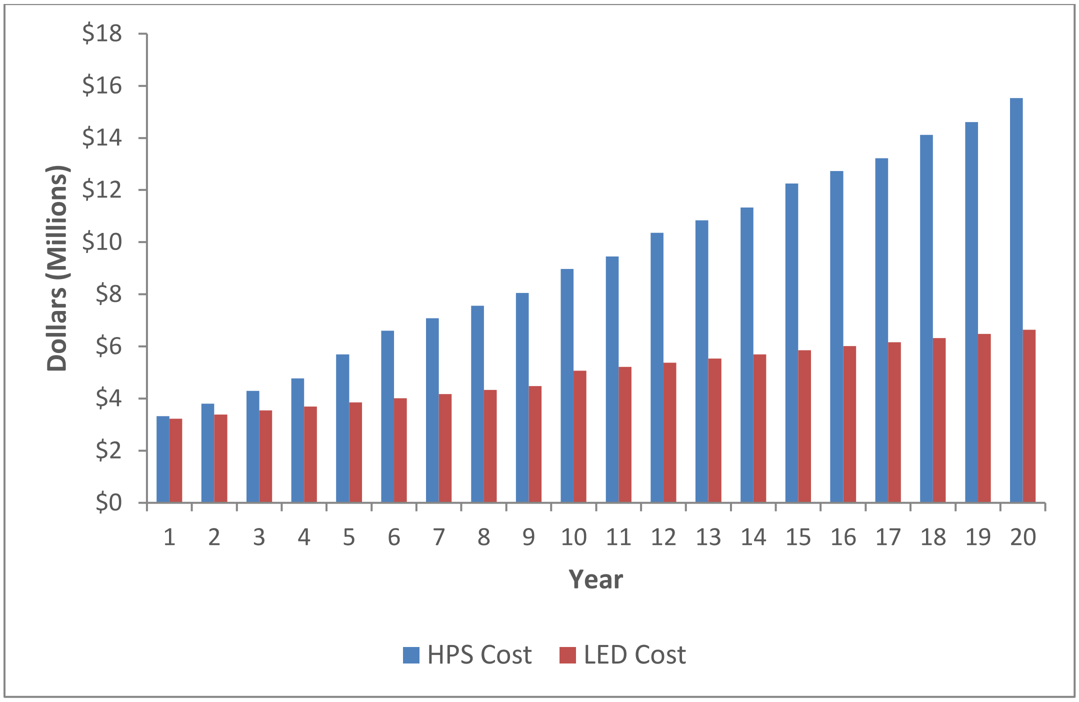

Figure 1: Cumulative Estimated 20-Year Cost Savings[1]

4.0 Project Description

The distribution in-service failures and miscellaneous upgrades portion of this project relates to annual expenditures required to upgrade the distribution system in response to in-service failures of equipment and the requirement to address localized service deficiencies, as well as small-scale infrastructure replacements due to storm damage.

The project includes expenditures related to the continued replacement of existing street lights with LED street lights as Hydro works to complete the retirement of HPS and MV street lighting in its system.

Table 2 provides the estimate for this project. The portion of the budget related to distribution upgrades is approximately $3.3 million while street light modernization accounts for approximately $0.5 million in 2022. Appendix A provides the forecast cost of the remainder of the street light modernization program; future year investments related to street light modernization will continue to be proposed as part of the annual capital budget application process.

[1] Including maintenance, energy consumption, and demand.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	1,109.0	0.0	0.0	**1,109.0**
Labour	1,641.0	0.0	0.0	**1,641.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	555.0	0.0	0.0	**555.0**
Other Direct Costs	341.2	0.0	0.0	**341.2**
Interest and Escalation	180.5	0.0	0.0	**180.5**
Contingency	0.0	0.0	0.0	**0.0**
Total	**3,826.7**	**0.0**	**0.0**	**3,826.7**

The project estimate is shown by Transmission and Rural Operations region in Table 3.

Table 3: Estimate for 2022 Upgrade Distribution Systems ($000)[2]

Region	Budget
Central	1,987.6
Northern	1,108.2
Labrador	730.9
Total	**3,826.7**

5.0 Conclusion

This is an annual, single-year project which provides a budget allotment for correction of issues identified through operational inspections and for as-required upgrades to the distribution system. During the course of normal work on street lights in 2022, Hydro will continue the systematic replacement of MV and HPS street lights on the Island Interconnected System with LED street lights as they provide cost savings over the life of the street light.

[2] Includes an estimated $90,000 to be recovered through CIAC.

Appendix A

Total Remaining LED Conversion Costs

Table A-1: Total Remaining LED Conversion Costs – All Regions

LED Fixture Size (W)	Fixture Count	Cost per LED ($)	Materials ($)	Labour ($)	Total ($)
100	5,346	170	908,820	1,069,200	**1,978,020**
150	622	300	186,600	124,400	**311,000**
250	405	400	162,000	81,000	**243,000**
400	34	600	20,400	6,800	**27,200**
				Total	**2,559,220**

Tab 21: Upgrade of Worst-Performing Distribution Feeders

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
Trevor C. Andrews
SIGNATURE
JUL 29/2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Upgrade of Worst-Performing Distribution Feeders (2022–2023)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Upgrade of Worst-Performing Distribution Feeders (2022–2023)

Category: Transmission and Rural Operations – Distribution

Definition: Other

Classification: Justifiable

Investment Classification: Renewal

Executive Summary

The Upgrade of Worst-Performing Distribution Feeders (2022–2023) project includes refurbishment of a distribution feeder located in the Bottom Waters system which has been prioritized through the examination of reliability performance data and confirmed as requiring upgrades to the existing infrastructure based on recent condition assessments. This project is required to improve the reliability of the Bottom Waters Line 1 ("BWT-L1") feeder, as well as the overall performance of the distribution system.

The BWT-L1 feeder was selected for upgrade at this time due to its five-year average performance in three key reliability indices – SAIDI,[1] SAIFI[2] and CHI.[3] Additionally, an assessment of its condition indicates that it requires upgrades at this time.

Newfoundland and Labrador Hydro ("Hydro") considered several options, including deferral of this project for a year, installation of a new feeder, and upgrading the existing equipment. Deferral of this project would create a growing backlog of deficiencies that would present an increased risk to distribution system reliability, which could potentially impact customer service and have a negative impact on future costs. Installing a new feeder would necessitate a level of investment that is not

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[1] System Average Interruption Duration Index ("SAIDI"). SAIDI indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year. This index is calculated excluding loss of supply outages, planned outages, customer request and major events.
[2] System Average Interruption Frequency Index ("SAIFI"). SAIFI is the System Average Interruption Frequency Index per year which indicates the average of sustained interruptions per customer served per year, or the average number of power outages a customer has experienced in the respective distribution system per year. This index is calculated excluding loss of supply outages, planned outages and customer request.
[3] Customer-Hours of Interruption ("CHI") is the sum of the products of the outage duration multiplied by the number of customers affected during the outage for each event within a one-year period. This index is calculated excluding loss of supply outages, planned outages, customer request and major events.

required for the continuation of reliable provision of electricity. As such, Hydro determined that upgrading the existing line is the most alternative solution to balance cost and reliability.

Hydro proposes to widen the right-of-way for 18 km of BWT-L1 feeder from 9 m to 26 m, and reroute a 12 km section of the line. Additionally, Hydro will: replace poles, cribs, and associated hardware, reframe three-phase structures, and install a three-phase sectionalizer. This work is planned for completion in 2023 with an estimated project cost of approximately $2,772,900.

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1.0 Introduction

Hydro provides service to residents in rural communities within the province through the use of distribution systems. Each distribution system typically consists of a substation coupled with wood pole distribution feeder(s) that supply power from the substation to service drops throughout a community. Historically, Hydro used a condition assessment based approach to identify components of its distribution systems which needed to be refurbished to ensure reliable operation. Since 2019, Hydro has also been focusing on refurbishment of distribution feeders which have poor reliability performance and/or which have significant impact on overall distribution system performance. The Upgrade of Worst-Performing Distribution Feeders (2022–2023) project includes refurbishment of a distribution feeder located in the Bottom Waters system which has been prioritized through the examination of reliability performance data and confirmed as requiring upgrades to the existing infrastructure based on recent condition assessments.

2.0 Background

Hydro's distribution feeder upgrades are prioritized based on five-year average reliability indices: SAIDI, SAIFI and CHI.

Hydro's worst-performing feeder list and a summary of data analysis is provided in Appendix A. Table A-1 ranks worst-performing feeders based on SAIDI per feeder, Table A-2 ranks worst-performing feeders based on SAIFI per feeder, and Table A-3 ranks worst-performing feeders based on CHI per feeder.

One of the drawbacks of selecting feeders based on the SAIDI or SAIFI method alone is that it considers the feeder-level indices and does not consider the impact the feeder has on overall system reliability indices. As such, directing resources to these feeders may not significantly improve overall system reliability. Alternatively, CHI ranks the feeder based on the impact the feeder has on overall reliability indices. Therefore, directing resources to these feeders will improve overall system reliability. However, this method may lead to overlooking smaller but still problematic feeders. To address this issue, Hydro examines worst-performing distribution feeders based on SAIDI, SAIFI, and CHI. The top 20 worst-performing feeders on each list are analyzed to identify the root cause of the poor performance. Where necessary, a feeder assessment is completed. This includes a review of current inspection data, overall system design, work completed on past capital projects, and a site visit to confirm data collected. Once the assessment is completed, Hydro selects the capital work that will improve the reliability of the distribution feeder and is justified by inspection data. For example, if an issue causing poor performance was due to an isolated incident or was recently addressed by other capital work, Hydro does not undertake any capital work and the feeder is identified for continued monitoring.

Hydro's most recent analysis of worst-performing distribution feeders has identified BWT-L1 as requiring upgrades. BWT-L1 is included as one of Hydro's worst-performing feeders from a SAIDI, SAIFI, and CHI perspective. This feeder has also been identified as requiring upgrades based on an assessment of its condition.

2.1 Existing System

BWT-L1 is a three-phase, 25 kV distribution feeder that originates from the Bottom Waters Terminal Station. It was originally constructed in the 1960s and services approximately 376 customers, including one large mining customer. The Bottom Waters Distribution System is shown in Figure 1 and Figure 2.

Figure 1: Layout of Bottom Waters Line 1

BWT-L1 runs from the Bottom Waters Terminal Station for approximately 25 km along Route 414 (La Scie Highway) to Route 418 (Ming's Bight Road) as a three-phase feeder with 2/0 AASC conductor. It then proceeds approximately 5 km along Route 418 as a three-phase feeder with 1/0 AASC conductor supplying Anaconda Pine Cove Mine and customers in the community of Ming's Bight. BWT-L1 also has an approximately 12 km single-phase tap which provides power to the communities of Woodstock and Pacquet.

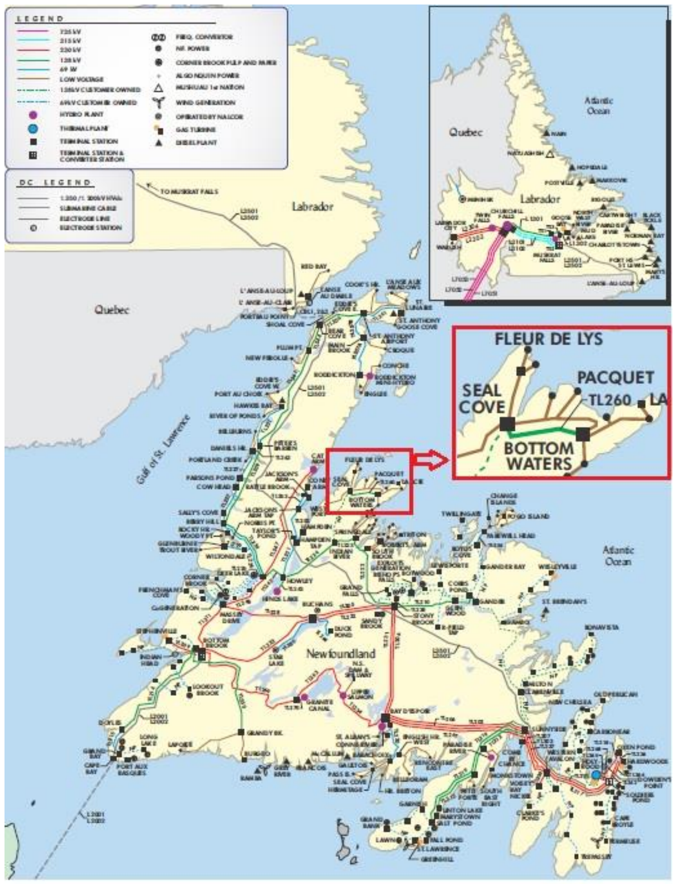


Figure 2: Location of Bottom Waters Line 1

2.2 Operating Experience

In the 2016–2020 period, vegetation was the main factor for poor performance of BWT-L1. Bottom Waters is a deep forest area; tree contacts are always a major concern for power outages in this system. The reliability experienced by the customers serviced by this feeder has also been impacted by several broken conductor and damaged insulator incidents in the 2016–2020 period.

Table 1 provides the reliability data for BWT-L1 as well as a comparison to Hydro's average, which indicates that this feeder has performed poorly relative to the Hydro average indices.

Table 1: Five-Year Average Reliability Data for BWT-L1 (2016–2020)

Location	SAIDI (Hours/Customer)	SAIFI (Interruptions/Customer)	CHI (Customer Hours)
BWT-L1	17.59	4.61	5,578
Hydro Average[4]	4.08	1.56	1,093

In general, the poor reliability statistics of BWT-L1 were driven by tree-related events, broken primary conductor, and damaged insulator incidents. The recent pole line inspection record indicates that this feeder has several deteriorated poles and damaged conductor spans. Figures 3 to 5 show pictures of deteriorated assets in BWT-L1.

Figure 3: Deteriorated Pole

Figure 4: Damaged Insulator

[4] Hydro Average CHI represents the average number of Customer Hours of Interruption per feeder. It is calculated by dividing the number of total customer-outage-hours by the number of distribution feeders.

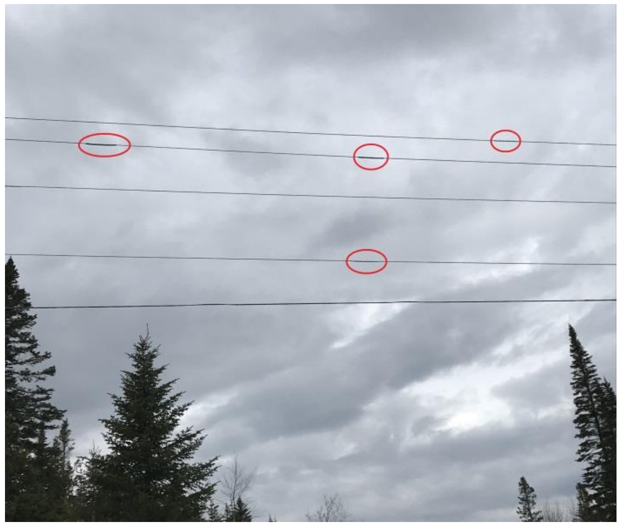


Figure 5: Deteriorated Conductor with Multiple Sleeves

For condition analysis and justification, the main three-phase part of this feeder has been divided into three sections, as shown in Figure 6.

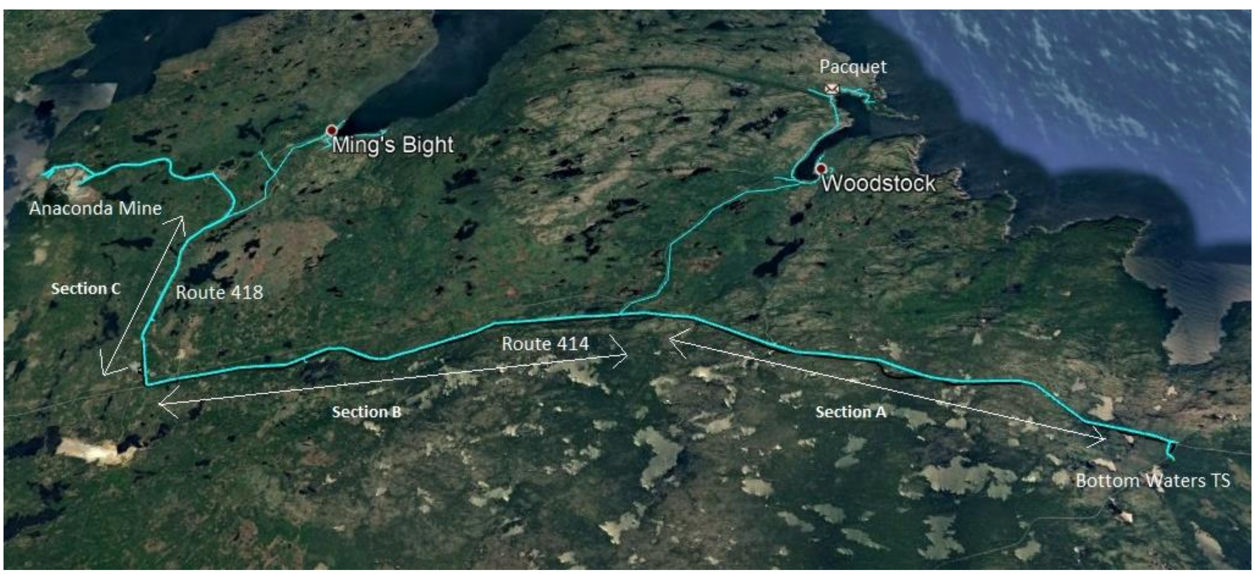


Figure 6: Sections A, B, and C – Bottom Waters Line 1

2.2.1 Section A

This section is approximately 12.5 km long, and is located off-road and is surrounded by large trees (see Figure 7). Tree contacts are very common incidents along this section of the line. Since vegetation is the primary concern, the history of vegetation control in the area has been reviewed. This line experienced a significant amount of cutting in recent years to maintain standard 9 m right-of-way. However, the section has numerous large trees outside the standard right-of-way which would come in contact with the primary conductor if they leaned or had fallen toward the line. A field survey has identified that most areas in this section require at least a 26 m right-of-way (see Figure 8). Therefore, widening the right-of-way from 9 m to 26 m is required to prevent tree contact incidents and improve reliability.

Figure 7: Right-of-Way Vegetation

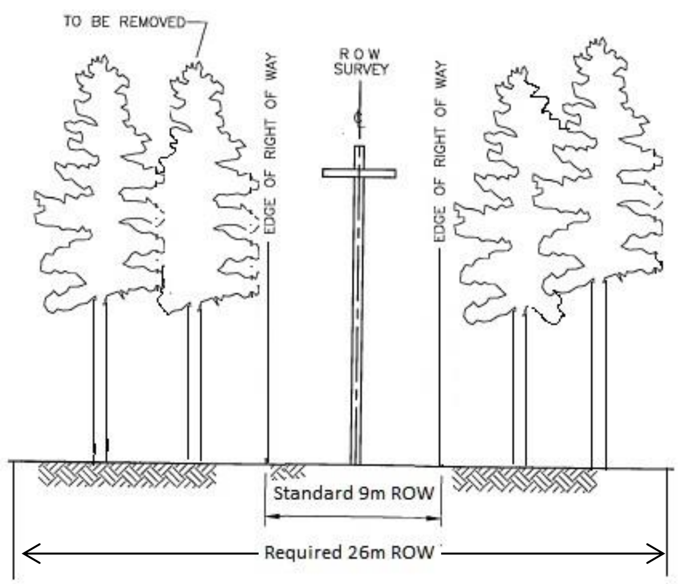


Figure 8: Required Right-of-Way Width

2.2.2 Section B

This section is approximately 12 km long and is the worst section of BWT-L1 from both a reliability and asset condition perspective. This section is off road and, similar to Section A, vegetation is one of the main factors contributing to its poor performance.

In addition, failure of the primary conductor has been an issue over the past number of years and there are multiple inline splice repairs in this section. Damaged insulator incidents in this section are also contributing to the poor reliability statistics.

There are a total of 160 poles in Section B and more than 95% of these poles are over 50 years old. It has also been identified that this section has several long-span structures which have to be addressed to eliminate galloping and the risk of line component failure. Due to the age and condition of the structures and line components, this section is becoming more prone to damage when exposed to heavy wind, ice and snow loading.

Rerouting this 12 km of BWT-L1 is the optimum solution to improve the reliability. Reroute of this section is required to: (i) mitigate tree contacts incidents, (ii) address the deteriorated conductors and insulators, (iii) address the long span issues, and (iv) improve structure accessibility and visibility. A part of the reroute layout is shown in Figure 9.

In addition to the reroute, a three-phase sectionalizer is proposed for installation on this section to improve reliability.

At the beginning of the feeder, a three-phase recloser is installed at the terminal station. The next three-phase recloser is approximately 30 km away. The single-phase tap serving power to the communities of Woodstock and Pacquet is connected to the main line between these two reclosers. When a fault occurs between these two reclosers, the terminal station recloser operates and locks out, resulting in an outage to all the customers served by BWT-L1. To minimize this impact, installation of an automated sectionalizer is proposed. Attachment 1 provides the proposed location of the sectionalizer. This will reduce the number of customers affected in the event of a fault downstream of the new sectionalizer.

Figure 9: Part of the Proposed Reroute Layout

2.2.3 Section C

This section is approximately 5.5 km. Tree contacts and damaged insulator incidents in this section have contributed to the poor reliability statistics. Similar to Section A, this part of the line requires tree cutting and widening the right-of-way from 9 m to 26 m. Insulator replacement is also required to improve the reliability.

3.0 Justification

This project is justified based on: (i) the reliability performance of the distribution feeder BWT-L1 and (ii) the current condition of the assets.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives for BWT-L1:

- Alternative 1: Deferral;
- Alternative 2: Construction of an entirely new distribution feeder; and
- Alternative 3: Widening right-of-way and rerouting and replacing deteriorated line components.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

If the required upgrading work is deferred to a future year, it would create a growing backlog of deficiencies that would have a negative impact on future costs and present an increased risk to distribution system reliability. Deferral of this work is not a viable alternative.

4.2.2 Alternative 2: New Distribution Feeder

This alternative involves the complete replacement of the existing feeders. There are existing feeder components that are still operable such as poles, conductor, insulators, and cross arms, and the construction of an entirely new feeder would eliminate the value of this equipment which is still functional. This alternative requires a level of investment that is not required for the continuation of reliable provision of electricity.

4.2.3 Alternative 3: Widening Right-of-Way and Reroute and Replace Deteriorated Line Components

Tree cutting to widen the right-of-way for the main branch circuit will reduce tree contacts related incidents and improve the feeder performance. Rerouting Section B of this line will reduce power outage incidents and materially improve overall performance. Replacing deteriorated line components will reduce the chance of outages due to deteriorated components. Continuing to utilize the existing non-deteriorated line components means Hydro would not incur the cost to replace line components before end of life.

4.3 Proposed Alternative

Based on the evaluation of the alternatives described in above, Hydro proposes Alternative 3 for BWT-L1.

5.0 Project Description

An overview of the work to be completed in this project is as follows:

- Widening the right-of-way from 9 m to 26 m for approximately 18 km (Section A and Section C) of the three-phase line;
- Rerouting Section B (12 km);
- Replacing/installing 33 poles, 3 cribs, and associated hardware;

- Reframing 62 structures; and
- Installing a three-phase sectionalizer.

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	575.4	0.0	0.0	**575.4**
Labour	122.3	309.3	0.0	**431.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	1,169.4	0.0	**1,169.4**
Other Direct Costs	12.6	68.4	0.0	**81.0**
Interest and Escalation	33.1	143.7	0.0	**176.8**
Contingency	106.6	232.1	0.0	**338.7**
Total	**850.0**	**1,922.9**	**0.0**	**2,772.9**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Resource planning	January 2022	January 2023
Design:		
Conduct site visits and detailed design	January 2022	October 2022
Procurement:		
Materials ordered	October 2022	December 2022
Construction:		
Construction	May 2023	September 2023
Close Out:		
Project close out	September 2023	November 2023

6.0 Conclusion

Hydro regularly executes larger feeder refurbishment and replacement projects to maintain or improve distribution system reliability performance. These larger upgrade projects are selected based on reliability performance analysis and condition assessments. This project is required to improve the reliability of the BWT-L1 feeder, as well as the overall performance of the distribution system.

Appendix A

Worst-Performing Feeder List and Summary of Data Analysis

Table A-1: Worst-Performing Feeders Sorted by SAIDI (Hours/Customer)

Rank	Feeder	SAIDI
1	Bottom Waters, Line 1	17.59
2	Burgeo, Line 5	17.22
3	Barachoix, Line 1	16.60
4	Farewell Head, Line 1	16.40
5	Black Tickle, Line 1	12.23
6	Roddickton, Line 4	10.97
7	Bottom Waters, Line 3	10.98
8	Jackson's Arm, Line 2	10.04
9	L'Anse-au-Loup, Line 2	9.95
10	Barachoix, Line 4	9.91
11	Bottom Waters, Line 7	9.58
12	English Harbour, Line 1	9.35
13	Kings Point, Line 1	9.32
14	Fleur-de-Lys, Line 1	9.19
15	Farewell Head, Line 4	9.01
16	Kings Point, Line 2	9.00
17	Main Brook, Line 2	7.85
18	Bottom Waters, Line 6	7.77
19	Glenbernie, Line 1	6.55
20	Fleur-de-Lys, Line 2	6.41

Table A-2: Worst-Performing Feeder Sorted by SAIFI (Interruptions/Customer)

Rank	Feeder	SAIFI
1	Bottom Waters, Line 1	4.61
2	L'Anse-au-Loup, Line 2	4.55
3	English Hr., Line 1	3.82
4	Barachoix, Line 1	3.74
5	Barachoix, Line 4	3.43
6	Farewell Head, Line 4	3.36
7	Roddickton, Line 4	2.94
8	Kings Point, Line 2	2.81
9	Bottom Waters, Line 7	2.79
10	L'Anse-au-Loup, Line 1	2.75
11	Kings Point, Line 1	2.69
12	Fleur-de-Lys, Line 1	2.63
13	Wabush, Line 11	2.48
14	Main Brook, Line 2	2.48
15	Bottom Waters, Line 3	2.51
16	Happy Valley, Line 15	2.43
17	Farewell Head, Line 1	2.39
18	Hawke's Bay, Line 3	2.38
19	Bear Cove, Line 6	2.35
20	Cartwright, Line 1	2.32

Table A-3: Worst-Performing Feeders Sorted by CHI (Customer Hours)

Rank	Feeder	CHI
1	Barachoix, Line 1	8,967
2	Barachoix, Line 4	8,034
3	English Hr., Line 1	7,529
4	L'Anse-au-Loup, Line 2	6,094
5	Bottom Waters, Line 1	5,578
6	Bottom Waters, Line 7	4,211
7	Happy Valley, Line 7	5,456
8	Kings Point, Line 1	5,227
9	Hawke's Bay, Line 3	4,820
10	Farewell Head, Line 4	3,692
11	Bear Cove, Line 6	4,357
12	Farewell Head, Line 5	2,732
13	Glenbernie, Line 1	3,276
14	Farewell Head, Line 6	2,131
15	South Brook, Line 1	3,301
16	Jackson's Arm, Line 2	2,948
17	St. Anthony, Line 1	2,754
18	South Brook, Line 5	2,716
19	Nain, Line 1	2,651
20	St. Anthony, Line 3	2,556

Table A-4: Summary of Data Analysis

Feeder	Summary
Barachoix, Line 1	In 2020, tree contacts have reduced reliability compared to prior years. Overall reliability statistics on this feeder have been impacted by several broken primary conductor, hardware and equipment failures incidents. This feeder was upgraded as part of the 2019–2020 Distribution System Upgrades project. No work is required at this time.
Barachoix, Line 4	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents. This feeder was upgraded as part of the 2019–2020 Distribution System Upgrades project; no work is required at this time.
Bear Cove, Line 6	Conductor failure and equipment failures are dominating outage causes in recent years. Work is being carried out on this feeder under the 2020–2021 Distribution System Upgrades project.
Black Tickle, Line 1	Customers served by this feeder experienced power outage due to weather-related events and defective line hardware; however, reliability of this feeder was mainly impacted by the remoteness of the site. Power outage was often extended due to remote access.
Bottom Waters, Line 1	During the 2016–2020 period, vegetation was the main factor for poor reliability performance. Reliability statistics were also impacted by broken insulator and damaged conductor incidents. A feeder assessment of this feeder has been completed recently and upgrade of this feeder is recommended. Details are provided in the main report “Upgrade of Worst-Performing Distribution Feeders (2022–2023).”
Bottom Waters, Line 3	Overall reliability statistics on this feeder have been impacted by several weather events, tree-related incidents, and broken line component issues. Line upgrading work has been completed on this feeder under the 2019–2020 Distribution System Upgrades project.
Bottom Waters, Line 6	Poor reliability statistics were driven by several weather events, tree-related incidents, and line hardware failures. Upgrade project completed in 2020; no additional work is required at this time.
Bottom Waters, Line 7	Overall reliability was impacted due to broken line hardware (e.g., insulators, cross arm, primary conductor, overhead transformer). This feeder was upgraded as part of the 2019–2020 Distribution System Upgrades project; no work is required at this time.
Burgeo, Line 5	Poor reliability statistics were driven by numerous overhead line hardware issues, broken conductor, and faulty distribution transformers. This feeder is located in extremely remote area. Power restoration is often delayed significantly due to limited access during adverse weather. This feeder will continue to be monitored to determine if it should be considered for upgrade in a future capital budget.

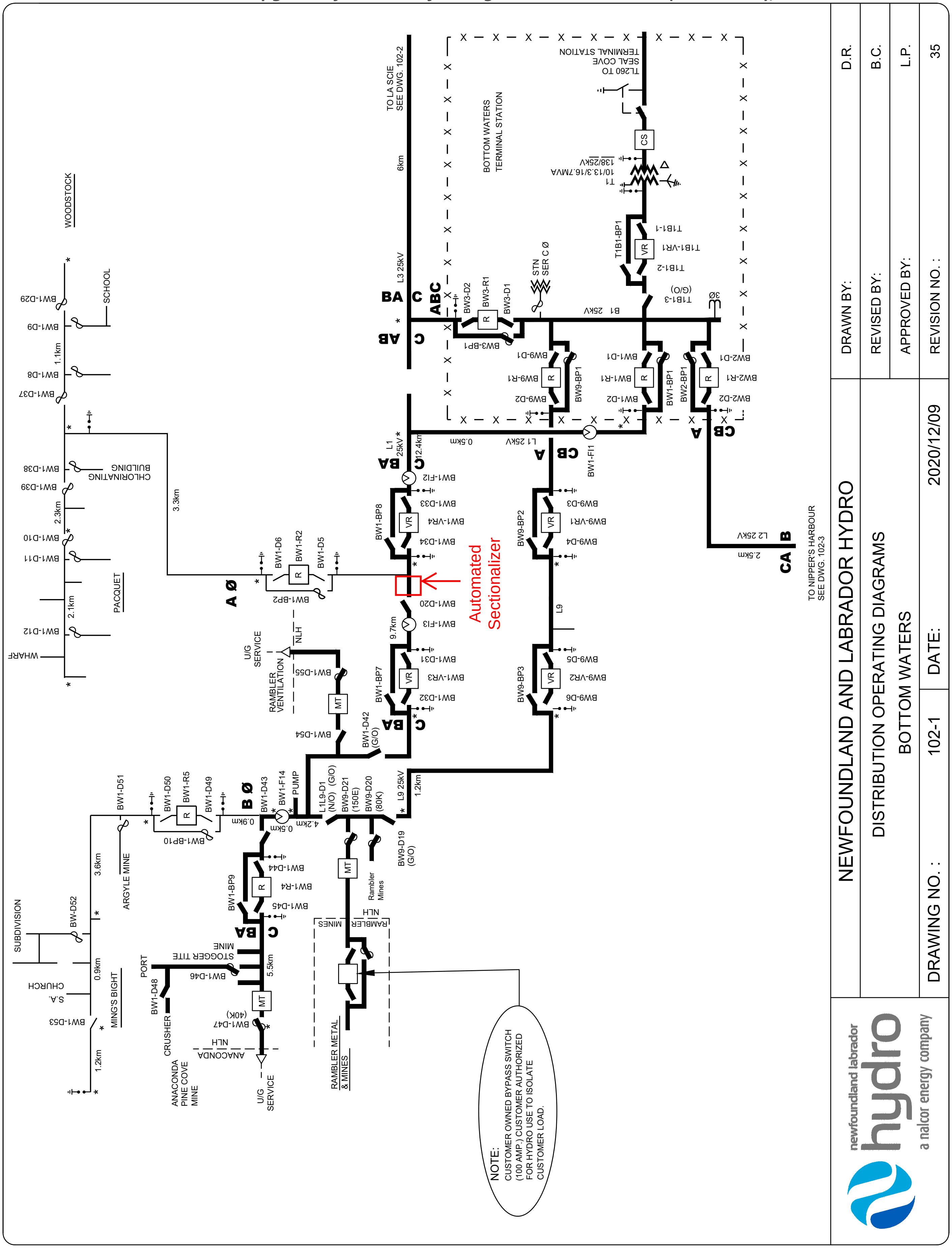
Feeder	Summary
Cartwright, Line 1	Overall reliability statistics on this feeder have been impacted by numerous issues. An upgrade project was completed in 2019. Since then, reliability has generally been good. No additional work is required at this time.
English Hr, Line 1	Poor reliability statistics were driven by several weather events, tree-related incidents, broken pole, and line hardware failures. System protection equipment coordination could have reduced affected customer numbers. Fuse/recloser coordination study and system protection review is recommended.
Farewell Head, Line 1	In 2016, all customers of this feeder experienced a 16-hour power outage caused by an overhead guy failure during adverse weather. Power outage was extended due to remote access. In 2018, two protective equipment issues (a faulty sectionalizer and a faulty circuit breaker) contributed to poor reliability statistics. In 2020, an icing event on FH1-R1 impacted the reliability. Work is being carried out on this feeder under operational project.
Farewell Head, Line 4	Multiple incidents of broken primary conductor contributed to poor reliability statistics. The primary line of FHD-L4 consists of portions of #2 ACSR conductor; which is non-standard and prone to failure. There are a number of locations in the #2 ACSR conductor section where the primary conductor has failed, resulting in power outages. Work is being carried out on this feeder under the Upgrade of Worst-Performing Distribution Feeders (2021–2022) project.
Farewell Head, Line 5	This feeder has been experiencing power outage due to faulty equipment failures, deteriorated poles, broken line hardware, and damaged conductors. Work is being carried out on this feeder under the Upgrade of Worst-Performing Distribution Feeders (2021–2022).
Farewell Head, Line 6	Defective recloser events and broken overhead line hardware incidents impacted the reliability. FH1-R3 relay issue increases outage duration. FO6-D12 fuse caused one significant outage. System protection study underway.
Fleur-de-Lys, Line 1	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents. Work is being carried out on this feeder under the 2020–2021 Distribution System Upgrades project.
Fleur-de-Lys, Line 2	Overall reliability statistics on this feeder have been impacted by primary conductor and other defective line hardware incidents. Work is being carried out on this feeder under the 2020–2021 Distribution System Upgrades project.
Glenbernie, Line 1	The poor reliability statistics are driven by tree contacts in 2017 and 2018. In 2019, one broken disconnect switch impacted the reliability of that year. This feeder performed well in 2020. No work is required at this time.
Happy Valley, Line 7	Tree contacts are the cause of the majority of outages to L7 followed by line slap. Metering tank failure and an overheated connector on regulator were also significant issues. Tree cutting was completed in 2019. No work is required at this time.

Feeder	Summary
Happy Valley, Line 15	This feeder experienced power outages in 2019; however, reliability has generally been good otherwise for 2016–2020 period. No work is required at this time.
Hawke's Bay, Line 3	Poor reliability statistics were driven by a broken pole and several line hardware failure incidents. Work was completed on this feeder under the 2019–2020 Distribution System Upgrades project. No work is required at this time.
Jackson's Arm, Line 2	Poor reliability statistics were primarily driven by tree-related events. Vegetation issues will be addressed and no additional work is required at this time.
Kings Point, Line 1	Poor reliability statistics were principally driven by multiple tree-related incidents. Tree trimming is being carried out on this feeder. Recently, voltage regulator failure and auto sleeve/hot tap failures have impacted the reliability. Removal of auto sleeves and installation of stirrup are recommended.
Kings Point, Line 2	Poor reliability statistics were primarily driven by tree-related events. Tree trimming was completed in 2018. Since 2018, the reliability has generally been good. No additional work is required at this time.
L'Anse-au-Loup, Line 1	Major outages to this line were caused by a failed jumper wire and salt tracking. Insulator failures contributed to numerous smaller outages. Proper recloser/diesel automation could have reduced outages. Automation work is in progress.
L'Anse-au-Loup, Line 2	Overall reliability statistics on this feeder have been impacted by numerous recloser operations due to unknown reason. Poor reliability statistics were also driven by several broken insulator and damage primary conductor incidents. No work is required at this time but this feeder will continue to be monitored.
Main Brook, Line 2	This feeder performed well in 2016–2017. However, in 2019–2020, reliability statistics were driven by numerous equipment and line component issues. No work is proposed at this time but the feeder will continue to be monitored.
Nain, Line 1	Overall reliability of this feeder was impacted by broken line hardware incidents during the 2016–2020 period. Remote access of the site also contributed to the poor statistics. No work is proposed at this time but the feeder will continue to be monitored.
Roddickton, Line 4	In 2016, a weather event and resulting pole failure significantly impacted the reliability. Overall reliability statistics of this feeder have been impacted by broken line post insulators. Work is being carried out on this feeder under operational project.
South Brook, Line 1	Overall reliability statistics on this feeder have been impacted by trees falling across the line during wind storms. SB1-R2 CLPU issues and a burned recloser bypass switches were also significant causes. Problematic protection equipment is planned to be addressed by an operational project. Tree trimming was completed and no additional work is required at this time.
South Brook, Line 5	Overall reliability statistics were impacted by a prolong power outage due to a leaning pole incident in 2017. No work is required at this time.

Feeder	Summary
St. Anthony, Line 1	Conductor failure was the most significant outage cause in the 2016–2020 period. Conductor inspection is recommended to determine condition and type.
St. Anthony, Line 3	Overall reliability statistics on this feeder have been impacted by numerous issues. Work is being carried out on this feeder under the 2020–2021 Distribution System Upgrades project.
Wabush, Line 11	Problems in the Wabush Substation are the largest cause of outages to this line during 2016–2020. Upgrade project is in progress for the substation.

Attachment 1

Proposed Location of Sectionalizer


NEWFOUNDLAND AND LABRADOR HYDRO
DISTRIBUTION OPERATING DIAGRAMS
BOTTOM WATERS
DRAWN BY: D.R.
REVISED BY: B.C.
APPROVED BY: L.P.
REVISION NO.: 35
DRAWING NO.: 102-1
DATE: 2020/12/09
newfoundland labrador hydro
a nalcor energy company
Automated Sectionalizer
BOTTOM WATERS TERMINAL STATION
TL260 TO SEAL COVE TERMINAL STATION
T1 10/13.3/16.7MVA 138/25kV
TO LA SCIE SEE DWG. 102-2
TO NIPPER'S HARBOUR SEE DWG. 102-3
WOODSTOCK
SCHOOL
CHLORINATING BUILDING
PACQUET
WHARF
ARGYLE MINE
MING'S BIGHT
S.A. CHURCH
SUBDIVISION
PORT
CRUSHER
STOGGER TITE MINE
ANACONDA PINE COVE MINE
U/G SERVICE
RAMBLER VENTILATION
RAMBLER METAL & MINES
Rambler Mines
NOTE: CUSTOMER OWNED BYPASS SWITCH (100 AMP.) CUSTOMER AUTHORIZED FOR HYDRO USE TO ISOLATE CUSTOMER LOAD.

Tab 22: Labrador City L22
Voltage Conversion

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
Trevor C. Andrews
SIGNATURE
July 29/2021
DATE
NEWFOUNDLAND & LABRADOR

2022 Capital Budget Application

Labrador City L22 Voltage Conversion (2022–2023)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Labrador City L22 Voltage Conversion (2022–2023)[1]

Category: Transmission and Rural Operations – Distribution

Definition: Other

Classification: Normal

Investment Classification: Service Enhancement

Executive Summary

The Cooper Hill Substation, located in Labrador City, supplies 4.16 kV power via distribution line 22 ("L22") which services the Labrador Mall and approximately 35 residential customers. L22 is the only distribution line originating from the Cooper Hill Substation, where the voltage is stepped down from 46 kV to 4.16 kV through transformer T1. The Cooper Hill Substation serves the only remaining 4.16 kV loads in Labrador City.

Preventive maintenance work completed on Cooper Hill T1 in 2020 indicated that it is showing signs of deterioration and may be nearing the end of its useful life. In its existing configuration, there is no online alternative supply transformer in Cooper Hill Substation.[2] Further, as the customers on L22 are supplied at 4.16 kV, if T1 fails, the load cannot be transferred to another substation. In the event of a failure of transformer T1, restoration of L22 is estimated to take approximately one week.

Newfoundland and Labrador Hydro ("Hydro") considered a number of alternatives to eliminate the risk of a loss of supply associated with the failure of Cooper Hill T1, including refurbishing Cooper Hill T1 and establishing an on-site spare as well as options to convert L22 to a 25 kV line. Hydro's analysis determined the least-cost alternative is to convert L22 to a 25 kV line supplied from the Vanier terminal station. Voltage conversion of L22 will also require the replacement of existing pad-mounted transformers and high-voltage cables serving the Labrador Mall, which are over 40 years

[1] A lesser scope project was proposed and approved as part of Newfoundland and Labrador Hydro's 2021 Capital Budget Application. As per "2021 Capital Budget Application – Labrador City L22 Voltage Conversion – Project Cancellation," Newfoundland and Labrador Hydro, July 9, 2021, Hydro cancelled the project due to an expansion of the scope that was outside the approval provided by the Board of Commissioners of Public Utilities ("Board").
[2] The spare transformer that can replace T1 would require relocation from the Vanier Terminal Station and connection and commissioning within the Cooper Hill substation. There is no mobile substation located in Labrador to provide a backup supply in the event of a substation transformer failure.

old and at the end of their useful life, with 25 kV-rated equipment. Following the conversion of L22, the Cooper Hill Substation will no longer be required.

The estimated project cost is approximately $1,491,200 with planned completion in 2023.

Contents

List of Appendices

1.0 Introduction

The Cooper Hill Substation, located in Labrador City, supplies 4.16 kV power via L22 which services the Labrador Mall and approximately 35 residential customers. L22 is the only distribution line originating from the Cooper Hill Substation, where the voltage is stepped down through transformer T1 from 46 kV to 4.16 kV. Figure 1 provides a single-line drawing of Cooper Hill Substation and L22.

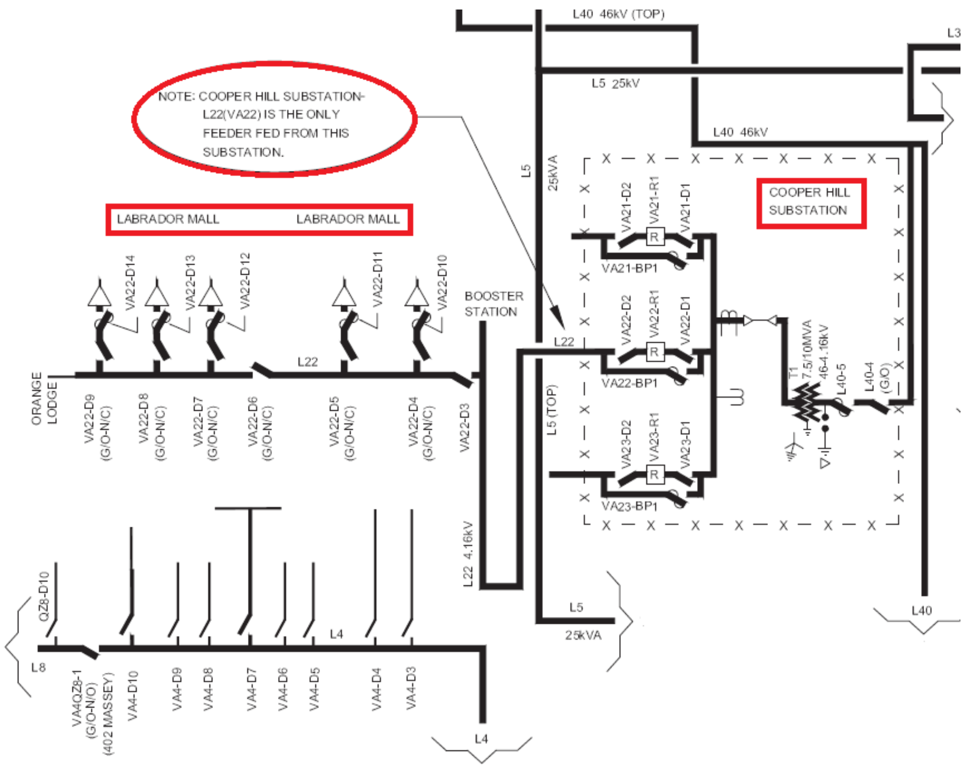


Figure 1: Single-Line Drawing of Cooper Hill Substation and L22

The Cooper Hill Substation serves the only remaining 4.16 kV loads in Labrador City. As the customers on L22 are supplied at 4.16 kV, if T1 fails, the load cannot be transferred to another substation. Additionally, in its existing configuration, there is no online alternative supply transformer in Cooper Hill Substation. To address this issue, Hydro is proposing to convert L22 to a 25 kV line and connect to the nearest 25 kV distribution line. This will eliminate the need for the Cooper Hill Substation and additional 4.16 kV spares.

2.0 Background

2.1 Existing System

2.1.1 Cooper Hill Substation

The Cooper Hill Substation is located in Labrador City and contains one 7.5/10 MVA, 46 kV/4.16 kV transformer, T1. L22 is the only distribution line supplied by Cooper Hill Substation.

In the event of a failure of Cooper Hill T1, the spare transformer that can replace T1 would require relocation from the Vanier Terminal Station, and connection and commissioning within the Cooper Hill Substation. There is no mobile substation located in Labrador to provide a backup supply in the event of a substation transformer failure. Figure 2 shows Cooper Hill Substation T1.

Figure 2: Cooper Hill Substation T1

2.1.2 Distribution System

L22 services the Labrador Mall and approximately 35 residential customers. Most of the residential customers supplied by L22 are supplied via dual voltage distribution transformers (4.16 kV or 25 kV); however, the Labrador Mall is served by five 4.16 kV pad-mounted transformers. To provide service to the mall, L22 is connected to riser poles at five different locations. Figure 3 to Figure 5 show pictures of existing riser pole, pad-mounted transformer and underground layout. The riser pole terminations are connected to pad-mounted transformers with underground cables which are rated for 5 kV and installed in buried conduits across the mall parking lot. The 5 kV cables and pad-mounted transformers were installed in 1977 and have reached the end of service life.

Figure 3: Existing Riser Pole

Figure 4: Existing Pad-Mounted Transformer

Figure 5: Existing Underground Layout

2.2 Operating Experience

T1 in the Cooper Hill Substation is 44 years old. The most recent preventive maintenance work, carried out in 2020, showed that the transformer was working normally. However, the latest dissolved gas analysis test completed in April 2021 revealed high levels of gassing in the unit; this indicates the presence of an internal hotspot connection on a bushing lead or on the off load tap changer.

The riser pole, associated hardware, underground cables and the pad-mounted transformers are more than 40 years old. Currently, there is no spare pad-mounted transformer or underground cables secured for this distribution system. In recent years, the mall has experienced several power outages due to in-service failures of some of these deteriorated assets.

3.0 Justification

This project is required due to: (i) the outage issues experienced by Labrador Mall; (ii) recent high levels of gassing in the unit; (iii) the age and condition of the assets; and (iv) lack of backup supply option in the event of failure of the Cooper Hill T1, the underground cables, or the pad mounted transformers.

When a transformer ages, it typically involves the degradation of its insulation system. This aging process reduces both the mechanical and dielectric strength of the transformer and, in turn, its reliability. Given customers served by L22 cannot be transferred to another substation as they are supplied at 4.16 kV, there is currently no mobile transformer available, and there are no spare transformers installed in the substation, there is risk of extended outage to customers connected to Cooper Hill Substation if the T1 transformer fails. This project eliminates this risk.

4.0 Analysis

4.1 Identification of Alternatives

Four alternatives were considered.

- Alternative 1: Relocate spare transformer and install in Cooper Hill Substation and refurbish Cooper Hill T1;
- Alternative 2: Convert L22 from 4.16 kV to 25 kV and install 25 kV pad-mounted transformers to service the Labrador Mall;

- Alternative 3: Convert L22 from 4.16 kV to 25 kV and install platform mounted stepdown transformer banks to service the Labrador Mall; and
- Alternative 4: Deferral.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Relocate Spare Transformer and Install in Cooper Hill Substation and Refurbish Cooper Hill T1

This alternative includes the relocation and installation of the spare transformer in the Cooper Hill Substation as a standby spare. This work consists of upgrades to the existing Cooper Hill substation, including the extension of the existing steel structure to accommodate the additional 46 kV supply, the installation of high side fuses to protect the spare transformer, the installation of a new transformer pad, the installation of new 5 kV cables to connect the spare transformer to the existing low voltage bus, the installation of 5 kV disconnect switches, the installation of current transformers required for metering, the replacement of two of the 5 kV reclosers, and grounding upgrades. The station work also includes refurbishment of the existing Cooper Hill T1 transformer. This alternative also includes replacement of infrastructure serving the Labrador Mall, including the replacement of underground cables, the installation of riser poles and associated hardware, and the procurement of a spare 1 MVA 4.16kV/600V pad-mounted transformer and spare 5 kV cable. The estimated cost of this alternative is $1,886,900.

4.2.2 Alternative 2: Convert L22 from 4.16 kV to 25 kV and Install 25 kV Pad-Mounted Transformers to Service the Labrador Mall

This alternative involves the conversion of L22 to 25 kV, the purchase and installation of five pad-mounted distribution transformers rated at 1 MVA, 25 kV/600 V, and the purchase of one spare 1 MVA, 25 kV/600v pad-mounted transformer. It also includes the replacement of the underground cables, riser poles and associated hardware. The estimated cost of this alternative is $1,491,200.

4.2.3 Alternative 3: Convert L22 from 4.16 kV to 25 kV and Install Platform Mounted Stepdown Transformer Banks to Service the Labrador Mall

This alternative involves the conversion of L22 to 25 kV, and installation of stepdown platform-mounted transformers and associated platforms to service the existing five 1 MVA pad-mounted transformers which supply the mall. It also requires the purchase of 15 transformers rated at 333 kVA, 25/4.16 kV to service the existing 4.16 KV pad mounts and 3 transformers rated at 333 kVA 25/4.16 kV to serve as spares. This alternative also includes replacing underground cables, riser poles, and associated hardware. The estimated cost of this alternative is $1,881,700.

4.2.4 Alternative 4: Deferral

This alternative involves continued operation of Cooper Hill T1 without a readily available spare transformer. This option also involves continued operation of the 4.16 kV distribution system with deteriorated hardware and equipment. Given the age and condition of the assets and lack of alternative supply options in the event of a failure of T1, this presents an unacceptable level of risk to distribution system reliability and is therefore not recommended.

4.3 Proposed Alternative

Converting L22 from 4.16 kV to 25 kV and installing 25 kV pad-mounted transformers to service the Labrador mall, identified as Alternative 2, is the least-cost alternative for the provision of reliable service; therefore, Hydro is proposing to proceed with Alternative 2.

5.0 Project Description

The work to be completed in this project is as follows:

- Purchase and installation of five pad-mounted distribution transformers, 1 MVA, 25 kV/600 V;
- Purchase of one spare pad-mounted distribution transformers, 1 MVA 25 kV/600 V;
- Conduit condition assessment and installation new conduits as required;
- Purchase and installation of 25 KV underground cables;
- Installation of 5 riser poles and associated hardware; and
- Provision of temporary generation to supply the Labrador Mall during construction.

Appendix A shows the relationship between Cooper Hill, Vanier Substation, and L22 before and after completion of the Labrador City L22 Voltage Conversion project.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	377.8	0.5	0.0	**378.3**
Labour	40.9	191.8	0.0	**232.7**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	624.2	0.0	**624.2**
Other Direct Costs	2.7	24.2	0.0	**26.9**
Interest and Escalation	23.3	78.9	0.0	**102.2**
Contingency	42.1	84.8	0.0	**126.9**
Total	**486.8**	**1,004.4**	**0.0**	**1,491.2**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Resource planning	January 2022	January 2023
Design:		
Conduct site visits and detailed design	January 2022	May 2022
Procurement:		
Materials ordered	May 2022	August 2022
Construction:		
Construction	May 2023	September 2023
Close Out:		
Project close out	September 2023	November 2023

6.0 Conclusion

Cooper Hill Substation has only one power transformer, T1, supplying the 4.16 kV L22 distribution line. In the event of a failure of Cooper Hill T1, the only spare transformer that can replace T1 is located in the Vanier Substation. It is estimated that restoration of L22 with the spare transformer would take approximately one week. In addition, there is no spare unit available for the distribution pad-mounted transformers and underground cables.

Cooper Hill T1 and the distribution assets are showing signs of deterioration. Failure of these assets presents a significant risk to the Hydro's ability to provide reliable service to customers served by L22

The least-cost alternative to eliminate the risk of a loss of supply from Cooper Hill Substation is to complete a voltage conversion of L22 and install pad-mounted transformers. The estimated cost of the work is $1,491,200. This project will support the provision of reliable energy for customers served by L22.

Appendix A

Labrador City Distribution System Configuration

1 Figure A-1 shows the existing relationship between Cooper Hill, Vanier Substation, and L22. Figure A-2
2 shows the proposed relationship between Cooper Hill (removed), Vanier Substation, and L22.

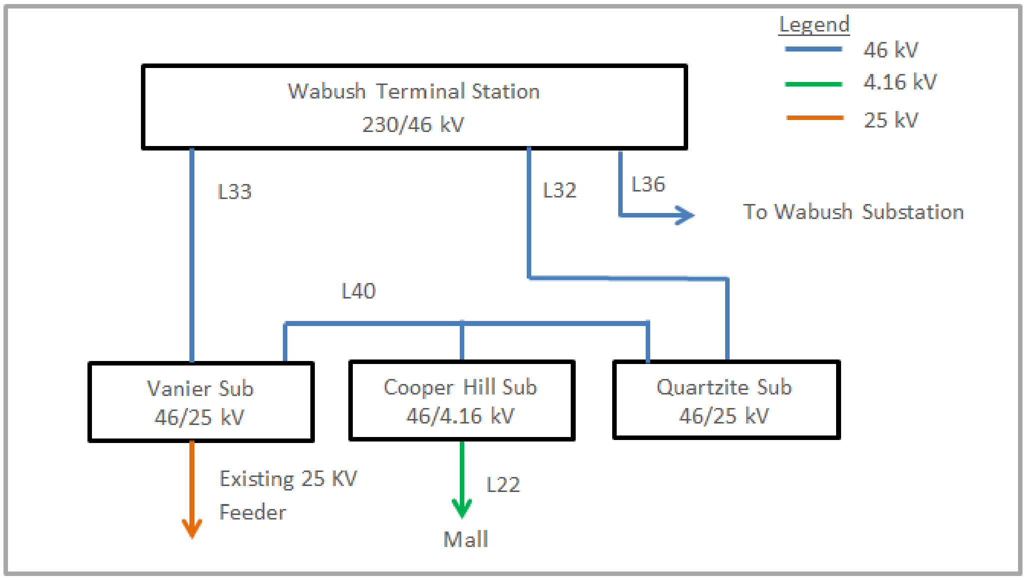


Figure A-1: L22 Existing Layout

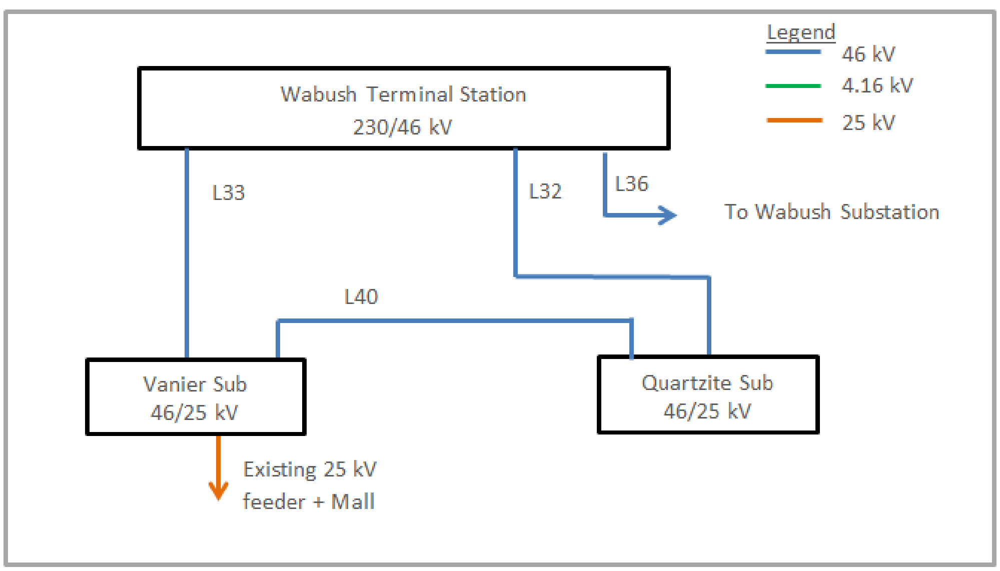
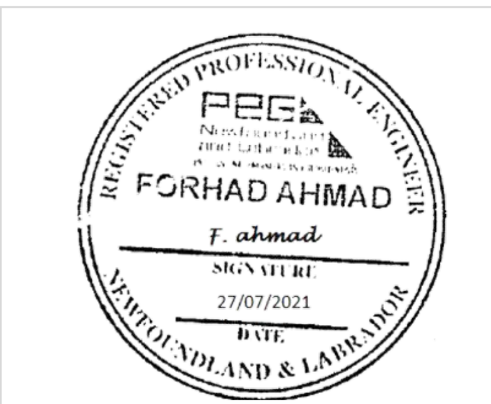


Figure A-2: Proposed Layout

Tab 23: Diesel Genset Replacement Unit 2039



2022 Capital Budget Application

Diesel Genset Replacement Unit 2039 – St. Lewis

July 2021

A report to the Board of Commissioners of Public Utilities

Diesel Genset Replacement Unit 2039 – St. Lewis

Category:	Transmission and Rural Operations – Generation
Definition:	Other
Classification:	Normal
Investment Classification:	Renewal

Executive Summary

The community of St. Lewis is located on the south coast of Labrador where Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 130 customers. Electricity is supplied by a diesel generating station operated and owned by Hydro. Currently, the plant contains three units with capacity of 365 kW (Unit 2039), 455 kW (Unit 2080), and 200 kW (Unit 2015).

Consistent with other utilities in Canada with prime power diesel plants, Hydro's Asset Management Program requires replacement of 1,800 rpm diesel gensets when they reach 100,000 operating hours. Unit 2039 is forecast to reach this threshold in 2023. Continuing to operate this unit beyond 100,000 hours would increase the likelihood of engine failure and reduce reliability for customers served by the St. Lewis Diesel Generating Station. If Unit 2039 were to fail, it could potentially result in rotating outages due to lack of firm capacity. As such, deferral of this project is not an acceptable alternative.

Hydro is proposing this project for the replacement of Unit 2039 diesel generator to maintain reliable operation of the St. Lewis Diesel Generating Station. This project is estimated to cost approximately $2,115,700 and is planned for completion in 2024.

Contents

1.0 Introduction

St. Lewis is located on the south coast of Labrador where Hydro provides electrical service to approximately 130 customers. Electricity is supplied by a diesel generating station operated and owned by Hydro. Currently, the plant contains three units; one rated at 365 kW, one at 455 kW, and one at 200 kW. Figure 1 is a map of Labrador showing the location of St. Lewis.

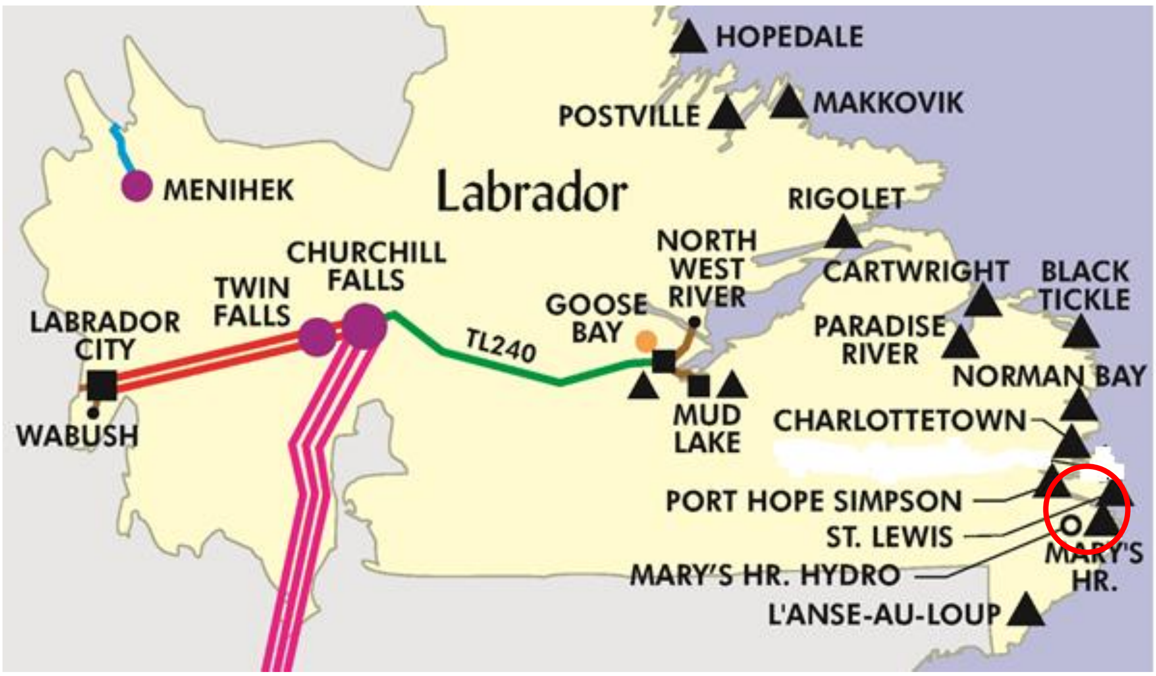


Figure 1: Location of St. Lewis Diesel Plant

2.0 Background

2.1 Existing System

There are three genets installed at the St. Lewis. All three units (Unit 2039, Unit 2080, and Unit 2015) are housed inside the power plant building. The size and installation date of each unit is as follows:

Table 1: Size and Installation Date of Units

Unit	Size (kW)	Year Installed
2039	365	1994
2080	455	2006
2015	200	1986

Figure 2: St. Lewis Diesel Generating Station

Figure 3: St. Lewis Diesel Generators in Power House

2.2 Operating Experience

As per Hydro's Asset Management Program, 1,800 rpm diesel gensets are typically replaced when they reach 100,000 operating hours. This genset replacement criteria is consistent with other utilities in Canada with prime power diesel plants.

Unit 2039 was installed in 1994 and has been overhauled six times, most recently in 2016 after accumulating 80,099 operating hours. Unit 2039 operated for approximately 2,500 hours per year the past five years. It is due for replacement at 100,000 hours, which is forecast to occur in 2023.

3.0 Justification

This project is required to support the reliability of the St. Lewis Diesel Generating Station, which requires all three units to serve the community. The unit is scheduled for replacement in 2023 based on Hydro's current asset management strategy and planning criteria which calls for replacement of 1,800 rpm gensets when they approach 100,000 hours of operation. If this unit were to fail, the community of St. Lewis could experience rotating outages due to lack of firm capacity until temporary generation could be added.

4.0 Analysis

4.1 Identification of Alternatives

Hydro requires that its isolated systems have sufficient firm capacity to meet peak demand; as such, non-dispatchable renewable energy sources and customer demand management are not considered viable alternatives for the provision of firm capacity.[1]

Hydro has evaluated the following alternatives:

- Alternative 1: Defer installing new unit to a future year; and
- Alternative 2: Complete new genset installation.

[1] Non-dispatchable generation refers to intermittent, variable generation sources whereby the supply cannot be adjusted to match demand on the system, potentially leading to capacity shortfalls during periods of reduced renewable energy generation.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Deferral

This alternative involves continued operation of existing unit 2039 past 100,000 hours. This would increase the likelihood of engine failure and reduce reliability. Deferring this project is not an acceptable alternative as Hydro would be in violation of its asset management criteria and genset failure is a significant reliability risk which could result in rotating outages due to lack of firm capacity.

4.2.2 Alternative 2: Complete New Genset Installation

Complete new genset installation to increase reliability and support continued firm capacity. The existing Unit 2039 was installed in 1994 and has been overhauled six times, most recently in 2016 after accumulating 80,099 operating hours. It is due for replacement after accumulating 100,000 hours, which is forecast to occur in 2023.

Hydro has completed a sizing study for the St. Lewis diesel generator unit 2039 replacement and has determined that replacing the unit with a similar size genset at around 365 kW is appropriate based on load forecast and operational efficiency. This size will offer the most operational efficiency of the diesel generating station while not reducing the firm rating of the plant.

4.3 Proposed Alternative

Hydro is proposing to replace Unit 2039 with a new 365 kW, 1,800 rpm diesel genset. New genset installation will support the reliable supply of electricity for customers of St. Lewis and Hydro will be able to meet firm capacity for 2023.

5.0 Project Description

This project is for the replacement of Unit 2039 with a new 365 kW, 1,800 rpm diesel genset. It includes design, procurement, and installation of a new genset, exhaust stack, radiator, after cooler, switchgear with breaker, communication equipment upgrade, and all other equipment necessary to facilitate the proper function of the new unit. Upgrades to some existing protection and control equipment will be required, including modifications to the main and genset 2 engine hall PLC[2] and replacement of genset 1, genset 2, genset 3, and main ion meters. Additionally, any assessment and/or modifications

[2] Programmable logic controller ("PLC").

required to existing plant systems (protection, controls, switchgear, PLC/HMI[3] software configuration etc.) as a result of the genset replacement will be executed in this project.

The budget estimate for this project is provided in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	28.9	394.4	0.0	**423.3**
Labour	252.4	697.2	56.7	**1,006.3**
Consultant	9.0	27.0	0.0	**36.0**
Contract Work	30.2	0.0	0.0	**30.2**
Other Direct Costs	27.9	214.6	19.7	**262.2**
Interest and Escalation	20.2	124.3	51.8	**196.3**
Contingency	28.4	126.3	6.7	**161.4**
Total	**397.0**	**1,583.8**	**134.9**	**2,115.7**

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

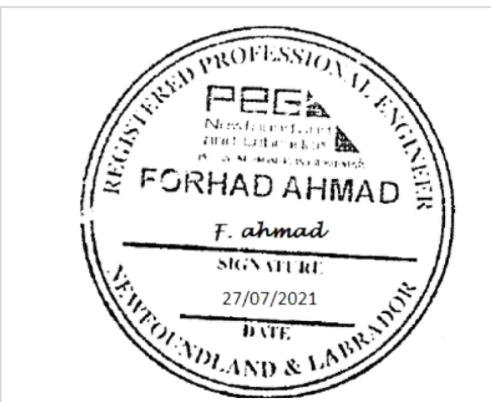
Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	January 2022	March 2022
Engineering:		
Site visit and design for P&C[4] upgrade	March 2022	August 2022
Procurement:		
All the required materials for P&C and mechanical supply contract and develop and publish tender	July 2022	March 2023
Construction:		
Remove old genset and P&C equipment and install new equipment	May 2023	August 2024
Commissioning (Manuel Mode):		
Run up the new genset without automation; confirm operation, and release to operations	August 2023	September 2023
Construction and Commissioning (Automation):		
PLC/HMI programming, PLC I/O wiring, PLC I/O and logic testing, confirm operation, and release to operations	July 2023	April 2024
Close Out:		
Close work order, complete all documentation, and complete lessons learned	March 2023	June 2024

[3] Human-machine interface (“HMI”).
[4] Protection and controls (“P&C”).

6.0 Conclusion

Hydro’s current asset management strategy is to replace 1,800 rpm gensets when they approach 100,000 hours of operation to support continued reliability of the diesel generating plants. Unit 2039 is expected to reach 100,000 hours in 2023; therefore, Hydro is proposing this project to replace the unit to maintain reliable operation of the St. Lewis Diesel Generating Station.

Tab 24: Diesel Genset Replacement Unit 2012



2022 Capital Budget Application

Diesel Genset Replacement Unit 2012 – L'Anse-au-Loup

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Diesel Genset Replacement Unit 2012 – L'Anse-au-Loup

Category: Transmission and Rural Operations – Generation

Definition: Other

Classification: Normal

Investment Classification: Renewal

Executive Summary

L'Anse-au-Loup is located on the south coast of Labrador where Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 1,000 customers. The majority of the electricity is supplied by the Lac-Robertson Generating Station, located in Quebec, through a surplus energy purchase agreement with Hydro-Québec. The L'Anse-au-Loup Diesel Generating Station is operated by Hydro for standby power due to the nature of the contract with Hydro-Québec which allows Hydro's customers to be interrupted at any time. Currently, the diesel generating station contains five units with an additional mobile unit outside.

As most power required by the community is supplied by Hydro-Québec, the L'Anse-au-Loup Diesel Generating Station does not run as frequently as most other units on Hydro's isolated diesel systems. Therefore, its units are more likely to require replacement due to age and obsolescence than reaching the threshold for replacement based on operating hours.[1] This is the case for L'Anse-au-Loup Unit 2012, a 1,100 kW, 3516 CAT Diesel generating set ("genset") which was installed in 1984. This unit has operated for approximately 88,000 hours but has reached the end of its useful life due to age, condition and obsolescence. Many parts are discontinued and no longer available; therefore, replacement is the only viable option as this facility is required to meet the community's electricity needs when power from Hydro-Québec is interrupted in accordance with the contract.

Hydro's cost-benefit analysis determined that replacing Unit 2012 with a 1,500 kW unit is the least-cost option as it addresses the need for increased firm capacity of the L'Anse-au-Loup Diesel Generating Station due to forecast load growth. This project is estimated to cost approximately $3,063,300 and is scheduled for completion in 2024.

[1] Hydro typically replaces 1,800 rpm units at 100,000 operating hours.

Contents

1.0 Introduction

Many communities in coastal Labrador are not connected to Hydro's Labrador Interconnected System for power supply. Communities on the coast are provided with electricity from diesel generating stations owned and operated by Hydro.

The community of L'Anse-au-Loup is located on the south coast of Labrador where Hydro provides electrical service to approximately 1,000 customers. The majority of the electricity is supplied by the Lac-Robertson Generating Station, located in Quebec, through a surplus energy purchase agreement with Hydro-Québec. The L'Anse-au-Loup Diesel Generating Station is operated by Hydro for standby power due to the nature of the contract which allows Hydro's customers to be interrupted at any time. The diesel generating station must be fully available to operate reliably at all times to meet peak load requirements in the absence of supply from Hydro-Québec.

Figure 1 is a map of Labrador showing the location of L'Anse-au-Loup.

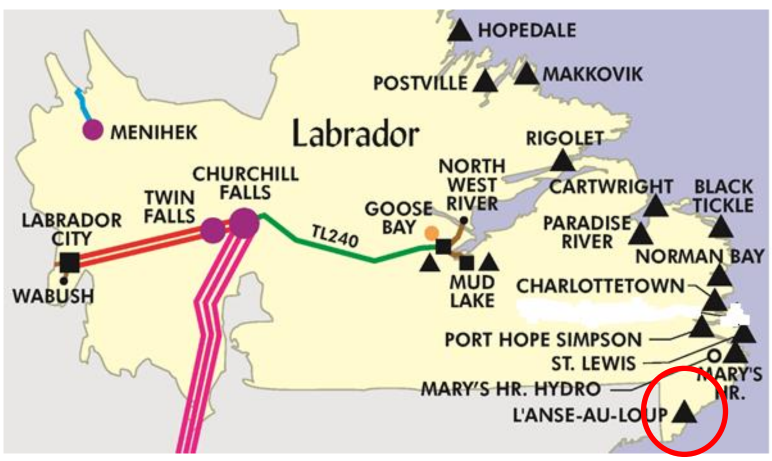


Figure 1: Location of L'Anse-au-Loup Diesel Plant

2.0 Background

2.1 Existing System

There are six gensets installed at the L'Anse-au-Loup Diesel Generating Station. The size and installation date of each unit is shown in Table 1.

Table 1: Gensets at L'Anse-au-Loup Diesel Generating Station

Unit	Size (kW)	Installed
2005	800	1988
2012	1,100	1984
2041	1,000	1988
2095	1,500	2017
2091	1,800	2015
2082 (Mobile)	1,825	2009

The L'Anse-au-Loup Diesel Generating Station is used to meet peak load requirements and as backup when the power supply from Hydro-Québec is limited.

The load growth forecast for L'Anse-au-Loup is shown in Table 2. The final year of the forecast indicates the expected peak load at 6,120 kW (99% of firm) which is very close to the plant firm capacity of 6,200 kW.[2]

Table 2: L'Anse-au-Loup 2020–2030 Peak Load Forecast

Year	Gross Peak (kW)
2020	5,895
2021	5,965
2022	6,000
2023	6,020
2024	6,035
2025	6,045
2026	6,060
2027	6,075
2028	6,090
2029	6,105
2030	6,120

[2] "Firm Capacity" refers to the plant's capacity with the largest unit out of service.

Figure 2: L'Anse-au-Loup Diesel Generating Plant

Figure 3: L'Anse-au-Loup Diesel Generators in Power House

2.2 Operating Experience

Unit 2012 is a 1,800 rpm diesel generating unit installed in 1984. Unit 2012 has already been overhauled four times,[3] most recently in 2001 at approximately 69,000 operating hours. At the end of 2020, the unit had accumulated approximately 88,000 operating hours. At present, the L'Anse-au-Loup Diesel

[3] A previous overhaul was completed before the 20,000 hour interval due to an unplanned engine failure.

Generating Station operates approximately 500 hours per year; however, it must always remain in reliable operating condition as it may be required to operate at any time.

Unit 2012 did not operate in 2020 as it was disassembled to assess engine condition and was determined to be near failure. Unit 2012 is obsolete—many of its parts have been discontinued and are no longer available. Due to its age and poor condition, Unit 2012 is now being used for emergency use only.

3.0 Justification

The supply from Hydro-Québec can be fully or partially interrupted at any time, including during extended planned maintenance outages at the Lac-Robertson Generating Station and during unplanned transmission interruptions which are primarily associated with storm conditions. Due to the interruptible nature of this agreement, the L'Anse-au-Loup Diesel Generating Station may be required to operate to supply the community of L'Anse-au-Loup at any time. To ensure it is able to reliably meet the electricity needs of its customers, Hydro must ensure all units within the L'Anse-au-Loup Diesel Generating Station are maintained in reliable operating condition.

Due to its age, poor condition, and obsolescence, replacement of Unit 2012 is required to maintain reliable operation of the L'Anse-au-Loup Diesel Generation Station and meet Hydro's firm capacity criteria.

4.0 Analysis

4.1 Identification of Alternatives

Hydro requires that its isolated systems have sufficient firm capacity to meet peak demand; as such, non-dispatchable renewable energy sources and customer demand management are not considered viable alternatives for the provision of firm capacity.[4]

[4] Non-dispatchable generation refers to intermittent, variable generation sources whereby the supply cannot be adjusted to match demand on the system, potentially leading to capacity shortfalls during periods of reduced renewable energy generation.

Hydro has evaluated the following alternatives:

- Alternative 1: Defer installing new genset to a future year;
- Alternative 2: Overhaul Unit 2012; and
- Alternative 3: Complete new genset installation.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Defer Installing New Genset to Future Year

This alternative involves continued operation of the existing Unit 2012. This would increase the likelihood of failure and reduce reliability as the genset is obsolete and at the end of its service life. Deferring replacement of Unit 2012 would result in an unacceptable risk of engine failure and violation of firm capacity criteria. In the event of a failure of Unit 2012, Hydro would have to rent a mobile generator until a new genset could be installed. The estimated cost would be approximately $300,000[5] in addition to the cost of the replacement unit. Additionally, the time required to procure, install, and commission a mobile generator is not conducive to the L’Anse-Au-Loup Diesel Generating Station’s role as backup supply in the event of a loss of supply from Hydro-Québec.

4.2.2 Alternative 2: Overhaul Unit 2012

Due to its age, condition, and obsolescence, completion of an additional overhaul of Unit 2012 is not a viable alternative. Parts are no longer available to allow for overhaul and the 2020 disassembly and assessment effort determined the genset to be near failure.

4.2.3 Alternative 3: Complete New Genset Installation

This alternative involves replacing Unit 2012 with a new genset. Completing the new genset installation is required to support reliability of the L’Anse-au-Loup Diesel Generating Station.

New Genset Sizing

Given that its units do not operate frequently, most units in the L’Anse-au-Loup Diesel Generating Station have a longer expected operating life than many of Hydro’s other diesel gensets. As such, it is necessary to thoroughly consider future system requirements when sizing replacement units. The existing Unit 2012 has a capacity of 1,100 kW; however, as there are no other scheduled genset

[5] Estimated based on approximately 12 months of rental at approximately $25,000 per month.

retirements in the immediate future, its replacement requires a higher capacity to address the forecasted increase in peak load. Taking this into consideration at this time will eliminate the need for Hydro to install additional units or upsize existing units earlier than planned to accommodate the forecasted load growth.

To determine the most cost-effective genset size to replace Unit 2012, replacement units with capacities ranging from 1,275 kW to 1,500 kW and standard rotational speed of 1,800 rpm were considered. Units greater than 1,500 kW were not considered as they would not physically fit without making significant structural changes to the diesel generating station, which are cost prohibitive. Hydro did not consider 1,200 rpm units due to the higher capital cost and operating nature of the facility.

From an overall plant perspective, Units 2005 and 2041, both installed in 1988, will likely require replacement in the medium term and Hydro considered how the replacement for Unit 2012 could influence those future replacements in this proposal.

A 1,500 kW replacement is approximately $100,000 more expensive to purchase than the 1,275 kW alternative but has several advantages. Adding 400 kW to firm capacity with a 1,500 kW unit at this time would address forecasted load growth and eliminate the need for Hydro to add capacity through addition of a new unit or upsizing an existing unit ahead of schedule. Installing a 1,500 kW unit at this time would also allow Units 2005 and 2041 to be replaced with a single, 1,500 kW unit when they are due for replacement, resulting in substantial savings and operational efficiencies.

To determine which genset size is the least cost, a cost-benefit analysis was completed with consideration of longer term capital and operational implications. The results of the cost-benefit analysis determined replacement with a 1,500 kW unit is the least-cost option. A summary of Hydro's analysis is included in Table 3.

Table 3: Cost-Benefit Analysis ($)

Genset Size	Cumulative Net Present Value ("CPW")	CPW Difference between Genset Sizes and the Least-Cost Option
1,500 kW	3,743,893	0
1,275 kW	4,481,186	737,294

Hydro assessed the sensitivity of its economic analysis with regards to the time frame for the next unit replacement in L'Anse-au-Loup and determined that replacement of Unit 2012 with a 1,500 kW unit remains the least-cost option provided Units 2005 and/or 2041 require replacement at any time prior to the year 2071.

4.3 Proposed Alternative

Hydro is proposing to replace Unit 2012 with a new 1,500 kW, 1,800 rpm diesel genset. This new genset installation will increase reliability, ensure Hydro will be able to meet firm capacity requirements beyond the 2030 peak forecast, and allow for future significant capital and operational savings.

5.0 Project Description

This project will replace Unit 2012 with a new 1,500 kW, 1,800 rpm diesel genset. It will include design, procurement, and installation of a new genset, exhaust stack, radiator, aftercooler, switchgear with breaker, and all other equipment necessary to facilitate the proper function of the new unit. Upgrades to some existing protection and control equipment will be required including additions to the motor control centre PLC[6] cabinet, modifications to the main PLC, HMI[7] configuration, and modification/testing of PLC logic. Modifications to the existing cooling system and addition of fuel coolers will be necessary to accommodate the new diesel genset. The estimate for this project is provided in Table 4.

Table 4: Project Estimate ($000)

Project Cost	2022	2023	Beyond	Total
Material Supply	17.7	1,084.9	0.0	**1,102.6**
Labour	249.6	754.8	60.3	**1,064.7**
Consultant	9.0	21.0	0.0	**30.0**
Contract Work	0.0	20.0	0.0	**20.0**
Other Direct Costs	22.6	245.3	5.2	**273.1**
Interest and Escalation	17.8	181.9	139.6	**339.3**
Contingency	23.2	205.3	5.1	**233.6**
Total	**339.9**	**2,513.2**	**210.2**	**3,063.3**

The anticipated project schedule is shown in Table 5.

[6] Programmable logic controller ("PLC").
[7] Human-machine interface ("HMI").

Table 5: Project Schedule

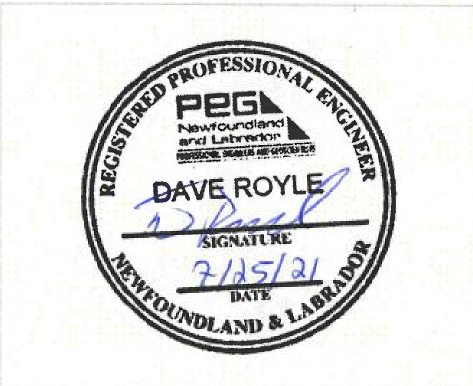
Activity	Start Date	End Date
Planning:		
Open work order and plan and develop detailed schedules	January 2022	March 2022
Engineering:		
Site visit and design for P&C[8] upgrade	March 2022	August 2022
Procurement:		
All the required materials for P&C and mechanical supply contract and develop and publish tender	July 2022	March 2023
Construction:		
Remove old genset and P&C equipment and install new equipment	May 2023	August 2024
Commissioning (Manuel Mode):		
Run up the new genset without automation; confirm operation, and release to operations.	August 2023	September 2023
Construction and Commissioning (Automation):		
PLC/HMI programming, PLC I/O wiring, PLC I/O and logic testing, confirm operation, and release to operations	July 2023	April 2024
Close Out:		
Close work order, complete all documentation and complete lessons learned	March 2023	June 2024

6.0 Conclusion

Unit 2012 at L'Anse-au-Loup has reached end of life and is obsolete. The unique operating nature of this facility provides limited opportunity to adjust plant capacity or configuration, requiring Hydro to thoroughly consider future system requirements in conjunction with the replacement of Unit 2012. Replacement of Unit 2012 with a 1,500 kW genset is the least-cost alternative to address near-term reliability and load growth while providing significant future capital and operating savings.

[8] Protection and controls ("P&C").

Tab 25: Replace Light-Duty Mobile Equipment



2022 Capital Budget Application

Replace Light-Duty Mobile Equipment (2022)

July 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Replace Light-Duty Mobile Equipment (2022) – Various

Category: Transmission and Rural Operations – Tools and Equipment

Definition: Pooled

Classification: Normal

Investment Classification: General Plant

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) operates a fleet of light-duty mobile equipment comprised of snowmobiles, ATVs,[1] light-duty trailers, heavy-duty trailers, and other miscellaneous equipment. This project provides for the replacement of 29 ATVs, 12 snowmobiles, 4 light-duty trailers, and 1 forklift in 2022. All of the mobile equipment proposed for replacement meets Hydro's established replacement criteria.

The fleet is distributed across Hydro's operating areas throughout the province and is utilized on a daily basis to support the maintenance and repair of the electrical system. As this equipment is often used in remote areas and under harsh conditions, it must be reliable to ensure the safety of the operator as well as the ability of the operator to effectively complete their job requirements.

Hydro has evaluated deferral of this project and determined that it is not a viable option due to its potential impact on employee safety and the increased risk of failures that could impede Hydro's maintenance and repair of the system and contribute to extended outages on the electrical grid. Hydro believes that deferral would be imprudent.

This project is required to support the reliable operation of Hydro's light-duty mobile equipment fleet. It is estimated to cost approximately $695,000 and is scheduled to be complete by the end of 2022.

[1] All-terrain vehicles ("ATV").

Contents

List of Appendices

1.0 Introduction

Hydro's mobile equipment fleet is strategically distributed across Hydro's operating areas and is utilized on a daily basis by support staff engaged in the maintenance and repair of the electrical system. Reliable light-duty utility equipment is required to enable Hydro's employees to effectively fulfill their duties.

In consultation with other utilities involved with the Canadian Utility Fleet Council, Hydro has established its mobile equipment replacement guidelines that consider the age and operating conditions for the equipment. Hydro's replacement criteria is shown in Table 1.

Table 1: Hydro's Replacement Criteria for Mobile Equipment

Equipment	Age (Years)
Snowmobiles/ATVs: Transmission Line Crews	3–5
Snowmobiles/ATVs: Other	5–10
Light-Duty Trailers 12'–16'	6–10
Light-Duty Trailers 22'–24'	5–8
Heavy-Duty Trailers	12–18

2.0 Background

2.1 Existing System

Hydro operates a fleet of light-duty mobile equipment comprised of snowmobiles, ATVs, light-duty trailers, heavy-duty trailers, and other miscellaneous equipment.

2.2 Operating Experience

As equipment ages, it experiences increased downtime that could negatively impact response times for emergency outages or planned maintenance. In many cases, light-duty equipment is regularly operated under harsh conditions and is subject to accelerated wear and tear.

Table 2 provides a history of light-duty mobile equipment purchases.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Equipment
2021	549.6	TBD	48	11 ATVs 10 Trailers 27 Snowmobiles
2020	499.6	441.7[2]	38	10 ATVs 14 Trailers 14 Snowmobiles
2019	469.6	436.2	35	10 ATVs 8 Trailers 17 Snowmobiles
2018	429.0	416.6	33	16 ATVs 1 Misc. 9 Trailers 7 Snowmobiles
2017	270.9	179.8	24	10 ATVs 1 Misc. 3 Trailers 10 Snowmobiles

3.0 Justification

This project is necessary to maintain a reliable light-duty equipment fleet. Failure to replace these units will lead to increasing maintenance costs and less reliable equipment. A reduction in equipment reliability would limit employees' ability to access the necessary work sites, impeding the maintenance and repair of the system and contributing to extended outages on the electrical grid. Further, as this equipment is often used in remote areas under harsh conditions, it must be reliable to ensure user safety.

4.0 Analysis

4.1 Identification of Alternatives

Hydro evaluated the following alternatives:

- Alternative 1: Defer replacements; and
- Alternative 2: Replace identified equipment.

[2] This was a one-year project that carried over into 2021. Most equipment will not be delivered until 2021 due to delivery delays as a result of the COVID-19 pandemic.

4.2 Evaluation of Alternatives

4.2.1 Alternative 1: Defer Replacements

Deferring the purchase of replacement equipment would be imprudent. The equipment outlined in this report is required to support remote operations at any time of the year, often during inclement weather conditions. If this equipment fails while personnel are traveling to generating stations or while accessing the transmission or distribution lines, the necessary repairs could be delayed, leading to failures or extended outages on the electrical grid. Additionally, unreliable equipment poses as safety risk to Hydro's employees who rely on the equipment to access their work sites. As such, deferral of the replacements is not a viable option for this project.

4.2.2 Alternative 2: Replace Identified Equipment

Alternative 2 is for Hydro to proceed with the purchase of the light-duty vehicles in accordance with the established criteria. This is required to support the safe and effective operation and maintenance of the electrical system. Hydro personnel typically utilize this type of equipment in remote areas with unreliable communication and during all weather conditions. The reliability of this equipment is critical for the safety of the operator and for the operator to be able to perform their required duties in a timely manner. For example, line crews regularly travel over rugged terrain with no roads or developed trails, requiring them to rely on ATVs and snowmobiles to safely access their work sites.

4.3 Proposed Alternative

Alternative 2 is Hydro's proposed option. Replacement of this equipment in accordance with Hydro's established criteria is prudent as it supports the safety of Hydro's employees and enables them to effectively complete the duties of their jobs. Further, it limits Hydro's exposure to increased maintenance costs and lack of reliability associated with older equipment.

5.0 Project Description

This project proposes the replacement of 29 ATVs, 12 snowmobiles, 4 light-duty trailers and 1 forklift in accordance with the replacement criteria provided in Table 1.

A detailed listing of the age of the assets being replaced under this project is provided in Appendix A.

The estimate for this project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	**2022**	**2023**	**Beyond**	**Total**
Material Supply	578.3	0.0	0.0	**578.3**
Labour	38.4	0.0	0.0	**38.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	11.2	0.0	0.0	**11.2**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	35.8	0.0	0.0	**35.8**
Contingency	31.3	0.0	0.0	**31.3**
Total	**695.0**	**0.0**	**0.0**	**695.0**

This project is scheduled for completion by December 31, 2022.

6.0 Conclusion

A fleet of reliable light-duty utility equipment is required to maintain the electrical system. Failure to replace the listed units poses an unacceptable risk to the safety of Hydro's employees who use the equipment in remote areas and under harsh weather conditions. Further, it will lead to increasing maintenance costs and less reliable equipment, which would have a negative impact on Hydro's ability to operate and maintain its system in a manner that is consistent with the provision of safe, least-cost reliable service. As such, Hydro believes it is prudent to replace the equipment identified in this project in 2022 in accordance with its established criteria.

Appendix A

Light-Duty Mobile Equipment Assets for Replacement

Table A-1: Light-Duty Mobile Equipment Assets for Replacement[1]

Type	Description	Age to Retire (Years)	Condition
ATV	V17476,18 Argo ATV	4	Not Reliable
ATV	V17477,18 Argo ATV	4	Not Reliable
ATV	V17478,18 Argo ATV	4	Not Reliable
ATV	V17479,18 Argo ATV	4	Not Reliable
ATV	V7097,07 Yamaha 400	15	Age/Condition
ATV	V7200,10 Outlander 400	12	Age/Condition
ATV	V7248,11 Polaris 400	11	Age/Condition
ATV	V7250,11 Polaris 400	11	Age/Condition
ATV	V7291,13 Polaris 6x6	9	Age/Condition
ATV	V7292,13 Polaris 6x6	9	Age/Condition
ATV	V7294,13 Outlander 400	9	Age/Condition
ATV	V7295,13 Outlander 400	9	Age/Condition
ATV	V7296,13 Outlander 400	9	Age/Condition
ATV	V7330,14 Outlander 400	8	Age/Condition
ATV	V7333,14 Outlander 400	8	Age/Condition
ATV	V7335,14 Polaris 6x6	8	Age/Condition
ATV	V7336,14 Polaris 6x6	8	Age/Condition
ATV	V7411,16 A. Cat 500	6	Age/Condition
ATV	V7412,16 A. Cat 500	6	Age/Condition
ATV	V7413,16 A. Cat 500	6	Condition
ATV	V7418,16 A. Cat 500	6	Condition
ATV	V7448,16 A. Cat 500	6	Condition
ATV	V7449,16 A. Cat 500	6	Condition
ATV	V7450,16 A. Cat 500	6	Condition
ATV	V7451,16 A. Cat 500	6	Condition
ATV	V7452,16 A. Cat 500	6	Condition
ATV	V7453,16 A. Cat 500	6	Condition
ATV	V7454,16 A. Cat 500	6	Condition
ATV	V7455,16 A. Cat 500	6	Condition
Snowmobile	V7165,09 Yamaha VK540 W.T	13	Age/Condition
Snowmobile	V7352,15 Skandic W.T	7	Age/Condition
Snowmobile	V7355,15 Skandic	7	Age/Condition
Snowmobile	V7356,15 Skandic	7	Age/Condition
Snowmobile	V7357,15 Skandic	7	Age/Condition
Snowmobile	V7381,16 Polaris 550	6	Age/Condition
Snowmobile	V7382,16 Polaris 550	6	Age/Condition

[1] This list provides the assets planned for replacement during 2022; however, if damaged equipment is identified during inspections in 2022 or a piece of light-duty mobile equipment fails while in service, Hydro may prioritize replacement of those pieces of equipment and defer purchase of an item planned under the scope of this project if such deferral is deemed to be appropriate at the time.

Type	Description	Age to Retire (Years)	Condition
Snowmobile	V7438,17 A. Cat L.T.	5	High Use/Condition
Snowmobile	V7442,17 Polaris 550	5	High Use/Condition
Snowmobile	V7443,17 Polaris 550	5	High Use/Condition
Snowmobile	V7444,17 Polaris 550	5	High Use/Condition
Snowmobile	V7445,17 Polaris 550	5	High Use/Condition
Light-Duty Trailer	V8001,18 Ideal 24‘	4	Roof/Structural
Light-Duty Trailer	V8952,12 Kargo Max 12’	10	Age/Corrosion
Light-Duty Trailer	V8953,12 Kargo Max 12’	10	Age/Corrosion
Light-Duty Trailer	V8995,17 Ideal 24’	5	Roof Flex/Condition
Heavy-Duty Equipment	V9789,90 Narrow Aisle Toyota Forklift	32	Age/Condition