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November 20, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: *Reliability and Resource Adequacy Study Review* – 2024 Near-Term Reliability Report

Further to the Board of Commissioners of Public Utilities' correspondence of August 17, 2023, approving Newfoundland and Labrador Hydro's ("Hydro") request to adjust the reporting frequency of its semi-annual reports on generation adequacy for the Island Interconnected System to annual in November each year,[1] enclosed please find Hydro's 2024 Near-Term Reliability Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
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Encl.

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[1] "Newfoundland and Labrador Hydro - Reliability and Resource Adequacy Study Review – Schedule for Future Updates," Board of Commissioners of Public Utilities, August 17, 2023.

Reliability and Resource Adequacy Study Review

2024 Near-Term Reliability Report

November 20, 2024

A report to the Board of Commissioners of Public Utilities

Executive Summary

Supply adequacy is a critical consideration for Newfoundland and Labrador Hydro ("Hydro") and its stakeholders. In this report, Hydro provides an in-depth view of system risks and mitigation measures to ensure customer requirements are met in the near term.

Overall, Hydro's load forecasting for 2024 has resulted in only minor changes compared to its 2023 forecast. Increases to peak demand continue to be projected year-over-year through 2029, both for utility and Industrial customers. Projected increases in economic factors, in addition to growth and investment in the mineral, aquaculture and oil sectors, along with shifts towards electrification, suggest a continued increase in demand requirements during the timeframe studied (2025–2029).

Hydro has utilized long-standing planning criteria to analyze five scenarios to assess near-term system reliability under a range of potential system conditions. Doing so ensures that Hydro can identify system risks and mitigation measures to ensure customer requirements are met during this period. The scenarios include the presentation of a Reference Case[1]—what Hydro expects to occur in the near term—as well as four other scenarios, including an increased forced outage rate ("FOR") for the Holyrood Thermal Generating Station ("Holyrood TGS") of 34%; both an increased and decreased equivalent forced outage rate ("EqFOR") for the Labrador-Island Link ("LIL") (10% and 1%, respectively); and consideration of the 2024 Slow Decarbonization load forecast as opposed to the 2024 Reference Case forecast.

As well, Hydro also considers four sensitivity scenarios with varying system constraints to further assess the effects on reliability for the Reference Case. These include: Holyrood TGS Unit 1 being unavailable for the 2024–2025 winter season; an increase and a decrease to the LIL bipole capacity (900 MW and 450 MW, respectively); and the early addition of a 150 MW combustion turbine ("CT") plant in 2029, allowing for the early retirement of Holyrood TGS Unit 3.

The results of the in-depth analysis suggest Hydro will achieve levels of reliability that are well within its planning criteria through the study period in the Reference Case. There are, however, some sensitivity scenarios where system conditions would result in exceeding reliability criteria. For instance, if the Holyrood TGS experienced a FOR of 34% through the next five years, then Hydro's planning criteria

[1] The Reference Case described in this report is specific to Hydro's 2024 near-term planning criteria and is independent from the Reference Case discussed in the 2024 Resource Adequacy Plan.

would be exceeded every year for the near-term period (2025–2029). Further, if the LIL EqFOR was 10%, Hydro would see higher-than-expected loss of load hours ("LOLH") for 2025 and 2029, as it would in 2025 if Holyrood TGS Unit 1 was out of service for the 2024–2025 winter season.

In summary, Hydro expects reliable system operation for the coming winter season with study results being well within specified planning criteria. Further, it is important to note that exceeding the planning criteria in this analysis does not necessarily mean an outage will occur; Hydro uses the results of its near-term planning to measure and evaluate evolving risks to ensure the reliability of the system in tandem with delivering environmentally responsible power, consistent with the lowest cost. Hydro remains committed to ensuring existing generating assets are in good condition while it implements new sources of generation to meet the province's demand and energy needs. Hydro will continue monitoring the health of its assets to ensure continued, reliable, least-cost supply for customers.

Contents

1.0 Introduction

Supply adequacy is a critical consideration for Hydro and its stakeholders. The enclosed assessment of the near-term resource adequacy provides an in-depth view of system risks and mitigation measures to ensure customer requirements are met during this period.

This report discusses near-term modelled resource adequacy and reliability and provides the results of the probabilistic resource adequacy assessment of the Island Interconnected System for the 2025–2029 study period. As described in the 2024 Resource Adequacy Plan,[2] the Labrador Interconnected System has very low supply risk due to the nature of the existing Churchill Falls contract.

The analysis was conducted consistent with the methodology proposed in the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document," which provides modelling *"practices, requirements, and recommendations needed to perform high-quality probabilistic resource adequacy assessments."*[3]

The reliability indices in this near-term reliability report include both annual and monthly LOLH, expected unserved energy ("EUE"), and Normalized EUE ("NEUE").[4] The analysis considers the different types of generating units (i.e., thermal, hydro, and wind) in Hydro's fleet, firm capacity contractual sales and purchases, transmission constraints, peak load, load variations, load forecast uncertainty, and demand-side management programs. Similar to previous analyses, a range of projected availabilities were considered for the Holyrood TGS and the LIL.[5]

2.0 Asset Reliability

Hydro files a quarterly report[6] with the Board of Commissioners of Public Utilities ("Board") that includes actual FOR[7] and their relation to the rolling 12-month performance of its units, historical

[2] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, p. 11 ("2024 Resource Adequacy Plan").
[3] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016, https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf.
[4] NEUE provides a measure relative to the size of the assessment area. It is defined as [(EUE ÷ Net Energy for Load) × 1,000,000] with the measure of per unit in parts per million ("ppm").
[5] A range of potential LIL bipole FORs was considered, consistent with the analysis conducted in the 2024 Resource Adequacy Plan and the "Reliability and Resource Adequacy Study Review - 2023 Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2023 ("November 2023 Near-Term Report").
[6] Hydro's Quarterly Report on Asset Performance in Support of Resource Adequacy (formerly known as the Quarterly Report on Performance of Generating Units) can be accessed at http://www.pub.nl.ca/indexreportspages/12MonthRollingAverage.php.
[7] FOR refers to an input to the Reliability Model that represents the percentage of hours in a year when a unit is unavailable.

reliability performance, and assumptions used in the assessments of resource adequacy. This quarterly report details unit reliability issues experienced in the previous 12-month period and compares performance for the same period year-over-year. The most recent report was submitted on October 31, 2024.[8]

Hydro has reviewed the factors affecting generating unit reliability since the November 2023 Near-Term Report. This report provides updates on these items as well as any additional items that may impact asset performance in the near term. Hydro aims to ensure issues affecting reliability have been appropriately addressed, as recurring issues can impact unit and system reliability if not managed. This section of the report summarizes the following: resolved issues; issues that have been addressed to the extent possible and are being monitored; ongoing issues; and, new issues since the November 2023 Near-Term Report. While not every isolated equipment issue (i.e., an issue that occurs once on a particular unit) is described in this report, each issue is investigated, with the root cause identified and corrected. These types of issues are reflected in the derated adjusted forced outage rate ("DAFOR") and derated adjusted utilization forced outage probability ("DAUFOP") which are used as inputs to the Reliability Model.

Section 2.1 to Section 2.4 describe issues—both asset-based and condition-based—that have previously affected reliability or may impact reliability in the near term, as well as the status of those issues and the actions taken to mitigate against potential impacts. The scope is not limited to generating assets (e.g., penstock, boiler tubes, etc.); it also considers environmental challenges impacting operations (e.g., frazil ice conditions). As part of this exercise, the following items have been identified and grouped by facility type:

- Hydraulic (Section 2.1):
    - Resolved Issues:
        - Rotor rim key cracking and rotor rim guidance block defects at the Upper Salmon Hydroelectric Generating Station ("Upper Salmon"); and
        - Control System reliability at the Granite Canal Hydroelectric Generating Station ("Granite Canal").

[8] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2024," Newfoundland and Labrador Hydro, October 31, 2024.

- Continued Monitoring:
  - The penstocks at the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir").
- New Issues:
  - Bay d'Espoir Unit 7 Generating Bearing Oil Coolers;
  - Vibration and shaft seal leakage at the Hinds Lake Hydroelectric Generating Station ("Hinds Lake"); and
  - Turbine seal clearances at Upper Salmon.

- Holyrood TGS (Section 2.2):
  - Resolved Issues:
    - Unit 3 East Forced Draft Fan motor;
    - Fuel Tank 1 inspection and refurbishment;
    - Fuel oil contamination; and
    - Unit 1 control valve stem failure.
  - Continued Monitoring:
    - Unit boiler tubes.
  - Ongoing Issues:
    - Variable frequency drives ("VFD");
    - Unit 3 turbine steam chest crack;
    - Unit 1 and Unit 2 turbine blades; and
    - Air compressors.
  - New Issues:
    - High-Pressure ("HP") Feedwater Heaters; and
    - Unit 2 and 3 Boiler Feed Pump Gland Seal Strainers.

- CT (Section 2.3):
    - Resolved Issue:
        - Stephenville Gas Turbine ("Stephenville GT") alternator cooling fan failure.
- Muskrat Falls Assets (Section 2.4)[9]
    - New Issues:
        - Repair Muskrat Falls Unit 2 Turbine;
        - Optical ground wire ("OPGW") Tower Peak and Top Plate Design;
        - Electrode Conductors;
        - DC current transformers ("DCCT") Cold Weather Operation; and,
        - Synchronous Condenser ("SC") Brush Gear Assemblies.

Any factors that impact unit availability, including those that have historically contributed to unit outages, are reflected in the reliability assumptions selected for each asset.

2.1 Hydraulic

2.1.1 Resolved Issues

2.1.1.1 Upper Salmon Rotor Key Cracking and Rotor Rim Guidance Block Defects

As previously reported in the May 2023 Near-Term Report,[10] the Board approved Hydro's application to undertake additional work in the 2023 outage season to address the required life extension activities.[11] Hydro proceeded with approved capital life extension activities required to remedy the issue, as outlined in the approved application, as well as the necessary corrections to the alignment of the turbine and generator assembly, and the unit was returned to service in December 2023. Since return to service, Hydro has completed two routine inspections of the rim key and guidance block assemblies in April 2024 and October 2024, which revealed no concerns.

[9] Hydro has incorporated reporting on the Muskrat Falls assets into its 2024 Near-Term Reliability Report. Issues which arose prior to the November 2023 Near-Term Reliability Report have been categorized as Ongoing Issues. Issues which arose since the November 2023 Near-Term Reliability Report have been categorized as New Issues.
[10] "Reliability and Resource Adequacy Study - 2023 Update - Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, June 2, 2023 ("May 2023 Near-Term Report").
[11] Board Order No. P.U. 18(2022).

Hydro considers this issue resolved; however, the inspection of these assemblies will be incorporated into the routine maintenance inspection program for the Upper Salmon Unit, at an appropriate frequency.

2.1.1.2 Granite Canal Control System

As previously reported in the November 2022 Near-Term Report,[12] an engineering assessment of the Granite Canal Control System has been completed in response to control system malfunctions experienced when remotely starting and/or stopping the unit at the Granite Canal. Modifications to equipment, as well as minor logic changes, were implemented in 2019. Additional hardware and instrumentation modifications were implemented during the maintenance outage in June 2020 to address the findings of the 2019 assessment. While there have not been any control system-related starting issues since the modifications were completed in 2020, there was an increased number of outages in 2021 and 2022 due to component failures, mainly temperature transmitters. As a result, an engineering review was completed and suitable alternative instruments were selected and installed.

A further investigation regarding the remaining useful life of the Granite Canal Control System determined that control system hardware, originally installed in 2003 at the time of the unit's commissioning, is either presently or soon-to-be obsolete and will require replacement. This replacement is now reflected in Hydro's capital plan and is planned for inclusion in Hydro's 2028 Capital Budget Application. To ensure the continued reliability of this system until the replacement is complete, a review of necessary spare components was completed and all identified items are available.

Hydro recently reviewed the effectiveness of the equipment and software modifications completed in 2020, the spare component inventory available, and the resolution of the temperature transmitter issues. At this time, Hydro does not foresee an increased risk of failure of the control system in the near term and is managing concerns related to obsolescence. As a result, Hydro has deferred the planned execution of any control system upgrade or replacement work to begin in 2028. Hydro continues to assess the system reliability on an ongoing basis and seeks opportunities to further mitigate the risk of outages to the unit at Granite Canal until the required life extension work is proposed, approved, and executed.

Hydro considers this issue resolved.

[12] "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2022 ("November 2022 Near-Term Report").

2.1.2 Continued Monitoring

2.1.2.1 Bay d'Espoir Penstocks

Condition assessments of Bay d'Espoir Penstocks 1, 2, and 3 were conducted in 2018, which included the completion of three reports prepared by a third-party consultant. These reports have been filed with the Board.[13] In response to the most recent failure of Penstock 1 in September 2019, SNC-Lavalin Group Inc. was engaged to complete an independent, detailed failure analysis of the most recent rupture and an engineering review of the work previously completed by Hatch Ltd. The failure analysis and engineering review results were also filed with the Board.[14] Hydro subsequently engaged Kleinschmidt to aid in the development of a project execution and strategy plan for life extension activities related to Bay d'Espoir Penstocks 1, 2, and 3.

Hydro's application for approval of the Bay d'Espoir Penstock 1 section replacement and weld refurbishment project was approved in Board Order No. P.U. 6(2023). Detailed design work for this project is complete and the construction contractor has been selected, with the award subject to Board approval of the revised project budget application filed with the Board on October 16, 2024. Construction is planned for completion in 2025 before the start of the 2025–2026 winter season.

Hydro has continued to take proactive measures to reduce down time, should another penstock leak occur, including maintaining an inventory of pre-rolled steel plates and confirming the availability of local welding resources. Modifications to the automatic generator control application in Hydro's Energy Management System, designed to limit the amount of rough zone operation, have remained in place for Units 1 to 6 at Bay d'Espoir. A more prescriptive operating regime has also remained in place for Units 1 and 2, given the history of Penstock 1, which serves these units. In this operating regime, Units 1 and 2 are limited to a minimum unit loading of 50 MW once dispatched and are not cycled or shut down as part of normal system operations.

The Penstock 3 inspection was completed in May 2024. Seven weld indications were discovered and subsequently repaired. As a result, there are no immediate concerns with the condition of the penstock.

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[13] "Penstock 1 Section Replacement and Weld Refurbishment – Bay d'Espoir Hydroelectric Generating Facility," Newfoundland and Labrador Hydro, December 7, 2022, sch. 1, app. G, H, and I.
[14] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

The inspection of Penstock 2 was completed in August 2024. During the inspection, findings concluded that there was no immediate concern with the condition of the penstock.

The inspection of Penstock 1 was completed in October 2024 and, although minor indications were found, it was determined that these indications pose no material concerns that would impact the penstock through the upcoming winter operating period. This decision was made considering the ongoing operational restrictions to limit starts, stops and rough zone operation as well as the fact that Penstock 1 is scheduled to be dewatered in the spring of 2025 for the commencement of life extension work.

Although Hydro has mitigated the risk of failure to the extent possible, there is a residual risk that a failure could occur before further life extension work is executed. Should a new failure occur, Hydro has estimated a 13- to 23-day repair timeline, depending on the circumstances.

Hydro will continue with the annual inspection program until such a time that the necessary life extension work has been completed.

2.1.3 New Issues

2.1.3.1 Bay d'Espoir Unit 7 Generator Bearing Coolers

During the return to service of Bay d'Espoir Unit 7 following the scheduled annual outage, Hydro experienced leaks in generating bearing coolers, resulting in a forced outage which lasted 13 days.

Initial investigation revealed that all four bearing coolers had experienced tube failures. To return the unit to service, Hydro used two available spares from inventory and worked with a local fabricator to assemble the remaining two coolers using the undamaged tubes from all four coolers. A successful pressure test of the coolers was completed and the unit returned to service in August 2024.

Hydro has procured two new coolers to replace the re-assembled coolers and intends to complete installation prior to the winter operating season.

2.1.3.2 Hinds Lake Unit Vibration and Shaft Seal Leakage

Since the filing of the November 2023 Near-Term Report, the unit has experienced higher-than-normal vibration levels and shaft seal leakage rates. Upon further investigation, no immediate concerns were identified with the equipment and measures were taken to further mitigate risk.

The Hinds Lake Unit will be available at full capacity this coming winter. Hydro continues to monitor both issues and to mitigate risk should concerns worsen, Hydro has proceeded with the procurement of bearing components and replacement parts for the shaft seal to ensure they are on hand in the event an outage is required.[15] If the unit condition does not worsen, Hydro intends to replace the procured parts during the planned 2026 overhaul.

2.1.3.3 Upper Salmon Unit Turbine Seal Clearances

During the execution of approved capital work in 2023, it was identified that the turbine seal clearances, both upper and lower, were below the Centre for Energy Advancement through Technological Innovation ("CEATI") tolerances for intervention. As a result, to mitigate the risk to the unit in the short term, Hydro adjusted the position of the rotating components relative to the stationary seals to improve the clearances. Following the completion of this work, Hydro was able to successfully increase the minimum clearance. Hydro notes that the clearance is still below the recommended intervention limit as recommended by CEATI, however provides a significant improvement over the as-found values. Hydro has implemented annual monitoring of these clearances to be completed during the annual planned outages to establish new trends going forward to best inform the timing of intervention to complete life extension activities, such as machining the turbine seal clearances.

Hydro completed the first annual seal clearance measurements in October 2024 and has found minimal change in clearances at this time. Another measurement will be completed in 2025 during the planned outage to continue annual trending.

2.2 Holyrood TGS

2.2.1 Resolved Issues

2.2.1.1 Unit 3 East Forced Draft Fan Motor

On October 23, 2023, Unit 3 was in start-up mode when a suspected failure of the East Forced Draft Fan motor occurred. Follow-up electrical testing confirmed that the motor required refurbishment, resulting in Unit 3 being derated to approximately 50 MW until the fan was returned to service in late November 2023. Investigation indicated that the failure was likely caused by a short due to a combination of moisture and contamination. The motor was refurbished using spare winding coils from inventory. Hydro has changed the preventive maintenance on these motors including an electrical test

[15] Procurement is ongoing within Hydro's Hydraulic In-Service Failure Program.

prior to start-up, which should identify any contamination or excessive moisture prior to energization of the windings. Hydro has replaced the spare coils and is considering the purchase of a spare motor for this fan, which would also be a spare for the Unit 3 West Forced Draft Fan. If deemed necessary, Hydro will proceed with the purchase of a spare motor within the Thermal In-Service Failures Project.

Hydro considers this issue to be resolved.

2.2.1.2 Fuel Tank 1 Inspection and Refurbishment

In September 2023, as crews were transferring No. 6 fuel oil from the tanker vessel to Tank 1, a small leak was identified on Tank 1. Once containment was complete, offloading recommenced with the No. 6 fuel oil being pumped to Tanks 2, 3, and 4.

The Holyrood TGS requires three tanks to be available for operation. As a result, Hydro utilized Tank 2, which was due to be retired during the summer of 2023, to facilitate repairs to Tank 1 and to ensure adequate fuel supply for the winter 2023–2024 season.[16] Hydro has completed additional repairs to Tank 1 and it was successfully returned to service on May 24, 2024. Shortly after this, Tank 4 was removed from service to facilitate the planned refurbishment of this tank. Tank 2 still contained oil at that time and this tank will remain in service until the Tank 4 overhaul is complete, which is expected prior to December 1, 2024. At that time, Hydro will prioritize the use of fuel from Tank 2 and proceed with plans to retire Tank 2.

Hydro considers this issue to be resolved.

2.2.1.3 Fuel Oil Contamination

In the fall of 2023, Hydro was experiencing issues with No. 6 fuel oil contamination. This resulted in the need for more frequent cleaning of fuel oil strainers and burner tips. Hydro had determined that the contamination was a result of the unplanned use of Tank 2 in response to the leak in Tank 1 (as discussed in the section above).

As the No. 6 fuel oil in Tank 2 had been consumed down to minimum storage, it is thought the No. 6 fuel oil added to Tank 2 stirred up the sludge from the bottom of that tank. Tank 2 was the first to be put in

[16] The utilization of Tank 2 is an emergency measure, taken after consultations with stakeholders.

service when Unit 1 was started up; as a result, sludge may have been carried down to the Day Tank, causing the contamination issue.

The condition subsided during the operating season, and is no longer a concern. Hydro considers this issue to be resolved.

2.2.1.4 Unit 1 Control Valve Stem Failure

On November 3, 2023, a Unit 1 turbine control valve stem failed in service. Unit 1 has six control valves and should be able to achieve full load, or near full load, with one valve unavailable; however, it was also determined at the time that another of the six control valves was binding, preventing full load operation of the unit. Hydro took Unit 1 offline and replaced the two failed control valves with the same valves from Unit 2 that was on forced outage waiting for the turbine rotor to be returned from the USA. The unit operated for the remainder of the 2023–2024 winter season. During the 2024 annual outage, in parallel with the turbine last stage blade ("LSB") replacements, Hydro sent the Unit 1 control valves for a full overhaul, as recommended by the OEM[17] and turbine service provider.

Hydro considers this issue to be resolved.

2.2.2 Continued Monitoring

2.2.2.1 Unit Boiler Tubes

Each of the three thermal generating units at the Holyrood TGS has a boiler that contains tubes, the failure of which are a common issue in thermal power plants.[18] To mitigate the possibility of tube failures, Hydro conducts a thorough annual tube inspection and test program, which was executed during the 2024 annual outage season, and is scheduled to reoccur in 2025. Hydro has determined that the boiler tube sections as a whole are in good condition; however, tube failures continue to pose a risk. Hydro maintains a thorough selection of spare tube material and a contract with an experienced boiler contractor for the provision of emergency repairs in the event of tube failures.

Hydro will continue to monitor the status of the unit boiler tubes and provide an update in the 2025 update of this report.

[17] Original equipment manufacturer ("OEM").
[18] Boiler tube failures are a common issue in thermal power plants due to the inherent design, which requires relatively thin walls for heat transfer to be subjected to high temperatures and stresses.

2.2.3 Ongoing Issues

2.2.3.1 Variable Frequency Drives

Forced draft fans provide the combustion air required for boiler operation at the Holyrood TGS. The VFDs were installed to more efficiently vary the amount of air supplied based on generation needs. This reduces auxiliary power requirements and results in fuel savings. Despite engaging the OEM for annual preventive maintenance work, following OEM recommendations to take significant mitigating measures to keep the drives clean and dry during outage periods, and pre-energizing the VFDs before start-up, Hydro has dealt with reliability issues related to this equipment since its installation.

As a result of the reliability issues and long lead times to restore or replace failed power cells (a vital component of the drives that have been prone to frequent failure), in September 2021, Hydro decided to bypass the VFDs on Unit 3 before the 2021–2022 winter operating season. This work was successful and eliminated this reliability concern for Unit 3.

During the 2022 outage season, Hydro completed the work to bypass the VFDs on Unit 2. This unit was returned to service without VFDs on the forced draft fans for the 2022–2023 winter operating season, and the fans have operated reliably since. Conversion of Unit 1 was not possible in 2022 and 2023 due to higher priority work on assets and the system. Hydro is proceeding with the plan to bypass the VFDs on Unit 1 during the remainder of its outage in 2024 and will return Unit 1 to service for the 2024–2025 winter operating season without them.

Once Unit 1 is returned to service, Hydro will consider this issue to be resolved.

2.2.3.2 Unit 3 Turbine Steam Chest Crack

Hydro has been monitoring a crack in the Unit 3 turbine steam chest since 1998. A repair completed by the OEM in 2001 was expected to prevent further crack growth for approximately 15 to 25 years. In 2019, some growth was observed, and a study completed by the OEM in February 2023 recommended re-inspection of the crack after nine start-stop cycles. As the 2024 inspection found no crack growth, the unit is cleared for operation for the 2024–2025 winter season. Should stop-start cycles be kept within the normal range for this unit, no further inspection of the crack will be required until summer 2025.[19]

[19] It is highly unlikely that the number of start-stop cycles will surpass the normal range for this unit; however, if they do, another inspection of the crack will be required, resulting in a unit outage of approximately two to three weeks.

Hydro intends to remediate this crack in 2025 under the proposed project to overhaul the Unit 3 steam turbine.[20] Hydro expects this work to be completed prior to December 1, 2025.

Hydro will provide a further update on this issue in the 2025 Near-Term Report.

2.2.3.3 Unit 1 and Unit 2 Turbine Blades

Since 2021, cracks have been found in the LSB on both the Unit 1 and Unit 2 turbine rotors. For safe and reliable continued operation, cracked blades cannot be repaired and must be replaced, which requires sending the turbine rotor to an approved facility. In 2023, in conjunction with the scheduled overhaul, the Unit 2 rotor was sent to a GE facility in the USA for LSB replacement. While there, it was discovered that the second LSBs also had cracks and required replacement. These replacement blades had not been pre-ordered and consequently, this caused a delay in the return to service of Unit 2 until the spring of 2024. The unit was returned to service on April 21, 2024 for commissioning. Vibration readings were higher than expected and some clearance adjustments were made. The Unit was returned to service in May 2024 for further commissioning. It operated for the final week in May before it was shut down and placed on standby. During that operating time, vibration was still elevated but met standards for long-term continuous operation. The OEM has provided technical support and recommends continued operation, with the expectation that vibration will continue to improve over time. Unit 2 was returned to service on October 11, 2024, for the winter season. Vibration is still elevated, as expected; however, there are no operational concerns.

The Unit 1 turbine rotor was removed during the 2024 annual outage and sent to General Electric ("GE") for replacement of the LSBs. This time, the planned scope included the second LSBs. Issues were found with the rotor-bearing journals that required additional time at the facility, which delayed the unit's return to service. The rotor was delivered to the site in early November, and it is currently expected that the unit will be returned to service in mid-January 2025.

Hydro will provide an update on the status of both units in the 2025 Near-Term Report.

2.2.3.4 Air Compressors

As a result of a recent failure, Hydro has two of its three air compressors available for service for the 2024–2025 operating season. A replacement for the failed compressor has been ordered; however, site

[20] Included in the scope of the "2025 Capital Budget Application," Newfoundland and Labrador Hydro, July 16, 2024, sch. 7, prog. 1.

delivery is not expected until after the 2024–2025 winter season. In order to supply the necessary compressed air to the various systems for which it is required, and provide system redundancy, Hydro has secured a 900 CFM[21] portable air compressor to temporarily connect to the system. The portable air compressor is an acceptable short-term solution and creates minimal risk to operational reliability. This unit will remain on site and in service as required until the failed compressor is replaced.

Hydro will provide an update on this issue in the 2025 Near-Term Report.

2.2.4 New Issues

2.2.4.1 HP Feedwater Heaters

Each Holyrood unit has three HP feedwater heaters. These heat exchangers transfer heat from steam extracted from various stages of the turbine to the feedwater entering the boiler. The primary purpose of these heaters is to improve the thermal efficiency of the units.

In recent years, Hydro has experienced increasing difficulty in operating the HP feedwater heaters, with the majority of the heaters unavailable for service during the 2023–2024 operating season due to tube bundle leaks.[22] The units can be operated reliably at full load without the HP feedwater heaters in service; however, extended operation without the heaters can cause premature failures of turbine and boiler components.

In 2024,[23] Hydro began a condition assessment program, under which all heaters will be opened for internal inspection and tube testing over the next two years. In 2024, one heater from each unit with a known tube leak was identified for assessment. The intention was that tube leaks would be corrected while completing the condition assessment, with the goal of a minimum of two of the three heaters on each unit returned to service for the 2024–2025 operating season.

Upon internal inspection, the selected heaters were found to be in worse condition than expected, with two unable to be returned to service and one identified that requires replacement.[24] Again for the 2024–2025 winter season, most HP heaters will be unavailable; however, as the units can be operated

[21] Cubic feet per minute ("CFM").
[22] The HP heaters transfer heat from steam outside of the tubes to the feedwater, which then passes through the tube bundles to the boiler. Each unit contains three heaters, which are intended to improve thermal efficiency.
[23] "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 21, 2023 (originally filed July 12, 2023), sch. 6, prog. 6.
[24] Hydro is currently assessing a path forward regarding the failed heaters, which may involve the proposal of a supplemental capital budget application for heater replacement in the near future.

reliably at full load without the heaters in service, the risk to the Holyrood TGS for this winter operating season is low.

Hydro will provide further information on this issue in the 2025 Near-Term Report.

2.2.4.2 Unit 2 and 3 Boiler Feed Pump Gland Seal Strainers

Each unit at the Holyrood TGS has two boiler feed pumps that supply HP water to the boilers for the production of steam. To seal the ends of the pump (glands) where the rotating shaft extends through, water is injected under pressure. This water is known as gland seal water, and its injection into the glands prevents the escape of HP feedwater around the shaft. Before the seal water reaches the glands, it passes through a strainer, which is designed to remove debris from the water and prevent the debris from entering the glands, where it could cause damage to the pump. The strainers are designed so that they can be cleaned without taking the pumps out of service.

The gland seal strainers on Units 2 and 3 are original and require replacement. While they are still effective in preventing debris from entering the glands, they can no longer be operated as designed to allow online cleaning. If the strainer fouls to the extent that the flow of seal water to the glands is compromised, it will be necessary to take the affected unit offline to clean or replace the strainer, which could result in a forced outage of four to five days. Based on Hydro's operational experience, fouling of the strainers is very unlikely to occur; as such, the risk of this forced outage is low.

Hydro intended to replace the strainers during the 2024 outage season, with replacements ordered for all three units; however, due to delivery delays, the new strainers could not be installed in Units 2 and 3 prior to their return to service.[25] At this time, Hydro considers the risk of strainer fouling on Units 2 and 3 to be insufficient to take the forced outage required for replacement. Operational monitoring of the gland seal pressure will enable Hydro to be proactive in scheduling an outage for replacement, in the unlikely event that it occurs. Should the units need to come offline for other reasons, Hydro intends to replace the strainers at that time.

Hydro will provide further information on this issue in the 2025 Near-Term Report.

[25] The new strainers were delivered to site in mid-November 2024. As Unit 1's return to service is extended to mid-January 2025, Hydro intends to replace the strainers on this unit before it comes back online.

2.3 Combustion Turbines

2.3.1 Resolved Issues

2.3.1.1 Stephenville GT – Alternator Cooling Fan Failure

In July 2023, the Stephenville GT tripped due to high vibration while operating in synchronous condense mode. During subsequent test runs, the alternator tripped due to high exciter and alternator temperatures. A visual inspection of the unit determined the vibration trip was caused by the failure of one of the alternator cooling fans.[26] The OEM was engaged to complete more thorough inspections and testing; it was confirmed the alternator cooling fan had failed and additional damage was observed on the stators winding insulation.

Based on the inspections, the OEM recommended that the alternator be removed from the unit. The alternator stator was repaired on-site in December 2023. The rotor was removed from the alternator and sent to the OEM's facility in the USA for inspection in November 2023. It was returned and reinstalled in the unit in early March 2024. However, the exciter which was also sent to the OEM repair facility was damaged during shipping back to the site. This resulted in a significant delay in the reassembly of the unit.

The Stephenville GT was released for service on September 27, 2024, and Hydro considers this issue to be resolved.

2.4 Muskrat Falls Assets

2.4.1 New Issues

2.4.1.1 Repair Muskrat Falls Unit 2 Turbine

This program is to repair the Unit 2 turbine, which will result in the unit being unavailable for the 2024–2025 winter season. The expected return to service date for this generating unit is mid-May 2025.

As recommended by the OEM and reported by The Liberty Consulting Group in its June 2023 monitoring report, vibration issues observed on Unit 2 require permanent corrective action, including full unit dismantling, to be completed under warranty by the turbine OEM.[27] There have been no issues with

[26] The alternator at the Stephenville GT has the cooling fan shrunk onto the rotor shaft, which forces air through the rotor and stator air gap, and then through the stator coils and core to remove heat from the alternator. Warm air is then cooled by the alternator cooling system and recirculates through the generator.
[27] "Nineteenth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System," The Liberty Consulting Group, June 8, 2023.

vibration, or the identification of other characteristics through internal inspections, which would indicate a problem similar to that of Unit 2 on Units 1, 3, or 4.[28]

The risk to near-term reliability associated with the planned outage of Unit 2 is mitigated by the fact that three units generating at Muskrat Falls are sufficient to support LIL deliveries to the Island Interconnected System during the 2024–2025 winter operating season.

Hydro will provide an update on the status of Unit 2 in the 2025 Near-Term Report.

2.4.1.2 OPGW Tower Peak and Top Plate Design

During December 2022, and February and March 2024, failure of the OPGW tower peaks occurred in heavy ice loading conditions, and there were two failures at the connection of the OPGW top plate during an icing event on the line in December 2022. The incidents involving these tower components did not cause a prolonged LIL outage; however, brief outages were required to repair the damage.

The root cause of the tower peak issue was determined to be unbalanced icing. Hydro is in the process of executing a project to determine a new unbalanced ice load criterion and complete a design and cost estimate to reinforce the towers for these loads. The design and cost estimate will be completed in the first quarter of 2025.

The root cause of the top plate issue was determined to be an error in the connection design. The connection on the top plate was not suitable for the design ice loads. An analysis was completed to determine which towers would be affected by this issue, with 63 towers identified. The A3 towers, which account for 61 of the affected towers, will be repaired by December 1, 2024. The two remaining structures are A4 towers, a design for which will be completed in the first quarter of 2025.

To mitigate risk to near-term reliability, Hydro has its Emergency Response Plan in place and has proceeded with the procurement of required materials to ensure they are on hand in the event a repair is required.

Hydro will provide an update on this issue in the 2025 Near-Term Report.

[28] Internal inspections have been completed on Unit 1 and Unit 3 turbines, with an internal inspection of Unit 4's turbine tentatively scheduled for 2026.

2.4.1.3 Electrode Conductors

During December 2022 and March 2024, there were issues with the electrode conductor during significant ice loading; the root cause of which was determined to be overloading due to ice and ice shedding.

Additional conductor testing has been completed from the incident in March 2024, with further recommendations expected from that investigation report once complete. Three alternative suspension clamp designs have been installed on the electrode conductor at ten structures and will be inspected yearly for performance. An assessment of the electrode suspension assembly will be completed in the first quarter of 2025. To mitigate risk should a similar incident occur in the near term, Hydro has its Emergency Response Plan in place, and has proceeded with the procurement of required materials to ensure they are on hand in the event a repair is required.

Hydro will provide an update on this issue in the 2025 Near-Term Report.

2.4.1.4 DCCT Cold Weather Operation

In 2023, the OEM and Hydro's Engineering teams determined that low ambient temperatures in the Muskrat Falls high-voltage direct current ("HVdc") Converter Station were influencing the measurement accuracy of DCCTs, resulting in false protection trips and power control issues on the LIL. The OEM identified the root cause of the issue to be a manufacturing defect with the Delay Coil Fibre Optical Cable located within the DCCTs; this issue occurred with a select batch of fibre-optic cables, affecting six DCCTs at the Muskrat Falls HVdc Converter Station, which have since been replaced.[29]

Recently, the OEM discovered additional DCCTs that require replacement due to cold temperature issues.[30] Two DCCTs have been identified to be replaced as a precaution based on site measurements; with replacement targeted by the end of 2024. Five additional DCCTs have been identified as low risk for this issue, and are being targeted for replacement during maintenance outages in 2025.

Hydro will provide an update on this issue in the 2025 Near-Term Report.

[29] One of these DCCTs has an operation rating of -40°C and will be replaced with a DCCT rated to -50°C as soon as is practical.
[30] While none of these additional DCCTs have experienced issues associated with cold temperatures, there are indicators the issue could present itself; therefore, as a precaution, they have been identified for replacement.

2.4.1.5 Synchronous Condenser Brush Gear Assemblies

Brush equipment performance on the Soldiers Pond SCs decreased in December 2023, resulting in several scheduled outages to replace damaged brushes, springs and brush holders.

Hydro's Engineering team, with the OEM for the brush equipment and SCs, have been working to identify the root cause of the brush performance issues. Multiple actions have been taken to improve the reliability of the SCs for this winter, including:

- 12 brushes per ring removed (24 total) on each unit to increase the current density (heat) on remaining brushes in an effort to improve patina development[31] and overall brush gear performance;
- Maintaining the machine hall temperature near 20°C;
- Nord-lock washers installed on holders to lessen the likelihood of brush holders vibrating loose and contacting the running face of the slip ring;
- Humidity levels being measured and trended by Hydro's Engineering team to ensure brushes are operating in ideal conditions to support patina development;
- Managing system voltages to increase load on SCs (i.e., increase current density); and
- Regular inspections performed to identify changes in performance, allowing for early intervention prior to damages.

In spring 2024, the existing slip ring was removed from SC1, and sent for machining to correct a runout causing excessive brush vibration. At this time, a modified brush with the ability to operate in a higher vibration environment was also provided by the OEM and installed. These modifications have resulted in improved performance to date. Hydro's Engineering and Operations teams will continue to monitor the overall impact of these changes, with the potential to complete this work on SC2 and SC3 in 2025. Additionally, GE has been working with a different brush gear manufacturer and has proposed a different brush assembly with a more robust spring design to lessen the likelihood of spring failure. This design will be installed on SC3 for performance evaluation in early spring 2025.

[31] During operation a protective film, or patina, is automatically formed on the surface of the slip ring, at the interface point between the brush face and ring surface. When formed properly, this film reduces brush wear to the lowest possible level and is essential to ensure the optimum operation of the brushes.

Hydro will provide an update on this issue in the 2025 Near-Term Report.

3.0 Modelling Approach and Assumptions

The analysis in this report has been completed using Hydro's Reliability Model. This model has been used to assess system reliability since the 2018 Reliability and Resource Adequacy Study, with updates to reflect current system assumptions.

Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these assessments are posted publically on the Newfoundland and Labrador System Operator's OASIS[32] website.

The following sections describe the performance rating assumptions used in the analysis, the assumptions around asset retirements, load forecast inputs, hydro reservoir storage conditions, availability of imports, and capacity assistance contracts.

3.1 Performance Ratings

Hydro's asset reliability is a critical component in determining its ability to meet planning criteria for the Island Interconnected System. As an input to the assessment of resource adequacy, unit FORs provide a measure of the expected level of availability due to unforeseen circumstances. Assumptions on FORs of generating units are updated annually in accordance with Hydro's FOR methodology which is described in the 2024 Resource Adequacy Plan.[33]

3.1.1 Hydro-Operated Generation Assets

Table 1 summarizes the near-term projected availability of Hydro's generating assets considered in the assessment of near-term supply adequacy. Assumptions used in the November 2023 Near-Term Report are included for comparison.

[32] Open Access Same-Time Information System ("OASIS"). https://www.oasis.oati.com/NLSO/index.html.
[33] 2024 Resource Adequacy Plan, app. B, att. 1

Table 1: FORs for Hydro-Operated Assets

Asset	November 2023 Reliability Metric	2024 Reliability Metric
Hydraulic Units[34]	DAFOR = 3.9%	DAFOR = 3.6%
Muskrat Falls	DAFOR = 3.9%	DAFOR = 2.3%
Holyrood Thermal Units: Base Assumption	DAUFOP = 20%	DAUFOP = 20%
Holyrood Thermal Units: Sensitivity Assumption	DAUFOP = 34%	DAUFOP = 34%
Holyrood CT	DAUFOP = 4.9%	DAUFOP = 4.9%
Stephenville GT	DAUFOP = 30%	DAUFOP = 30%
Hardwoods GT[35]	DAUFOP = 30%	DAUFOP = 30%
Diesels	DAUFOP = 6.6%	DAUFOP = 6.1%

3.1.2 Third-Party Operated Assets

For units not owned by Hydro, the FORs used in modelling are determined using industry averages provided in the 2022 Electricity Canada Generating Equipment Reliability Information System.[36,37] FORs used for assets owned by a third party in this analysis are presented in Table 2. Assumptions used in the November 2023 Near-Term Report are included for comparison.

Table 2: FORs for Third-Party Operated Assets

Asset	November 2023 Reliability Metric	2024 Reliability Metric
Hydraulic Units	DAFOR = 5.8%	DAFOR = 7.1%
Gas Turbines ("GT")	DAUFOP = 6.2%	DAUFOP = 5.2%
CBPP[38] Capacity Assistance (CoGen/Hydro)	DAUFOP = 19.2%	DAUFOP = 19.2%

[34] Excluding Muskrat Falls.
[35] Hardwoods Gas Turbine ("Hardwoods GT").
[36] The 2022 Electricity Canada Generating Equipment Reliability Information System provides five-year average statistics based on the years 2018–2022.
[37] EC reliability data is published annually. EC reliability data is not currently available for 2023.
[38] Corner Brook Pulp and Paper Limited ("CBPP").

Hydro has confirmed with Newfoundland Power Inc. ("Newfoundland Power") that its asset plan includes the retirement of both its Greenhill and Wesleyville GTs, as they are nearing the end of their service lives. Consistent with the assumptions made in the 2024 Resource Adequacy Plan, it is assumed that these units will be retired at the beginning of 2030.[39] Before retirement, Hydro has assumed a DAUFOP of 30%, in line with what is used for Hydro-owned GTs nearing end-of-life (i.e., both Stephenville GT and Hardwoods GT), to ensure Hydro is not over-relying on these units.

Hydro models wind generation from the Fermeuse and St. Lawrence Wind Projects stochastically using probability distribution functions developed based on historic generation data from winter and non-winter periods, which include forced and planned outages.

3.1.3 Labrador-Island Link

The LIL is an important component of supply for the Island Interconnected System and has performed reliably since it was commissioned on April 14, 2023. The 12-month annual average EqFOR for the period October 1, 2023 to September 30, 2024, was 3.28%.[40,41]

In Hydro's 2024 Resource Adequacy Plan, Hydro considered scenarios with a LIL EqFOR ranging from 1% (best case) to 10% (worst case), with 5% as the Reference Case with a LIL capacity of 700 MW. The assumptions used in the analysis in this 2024 Near-Term Reliability Report are consistent. The LIL has performed within this range in its first year-and-a-half of operation post-commissioning. However, multiple years of operational experience are required to better inform the longer-term selection of a bipole FOR. In the interim, the bipole FOR will be addressed with a range of upper and lower limits. As LIL performance statistics become available in the coming years, the FOR range may be narrowed in future filings.

[39] While Newfoundland Power is looking to retire these units, they have expressed that there may be justification to replace these units and the thermal units in the Port aux Basques region on the basis of long-term regional transmission reliability requirements and with the potential to support overall system reliability. While such assessments are beyond the scope of the *Reliability and Resource Adequacy Study Review* proceeding, Hydro is continuing to work with Newfoundland Power to explore these solutions and to understand their benefits in terms of provincial supply. Newfoundland Power is exploring the addition of 75 MW of CTs, with 25 MW operational in 2028, another 25 MW in 2029, and the final 25 MW in 2030.

[40] This EqFOR statistic was calculated based on the present rating of the LIL (700 MW).

[41] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2024," Newfoundland and Labrador Hydro, October 31, 2024.

Hydro anticipates a controlled 900 MW test will be performed on the LIL in December 2024, as system conditions permit. This 900 MW test will not test any additional functionality that was not already tested and passed during the 700 MW test.

3.2 Asset Retirement Plans

3.2.1 Holyrood TGS

Holyrood TGS Unit 1 and Unit 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. Combined, the three units provide a total firm capacity of 490 MW.

As described in the 2024 Resource Adequacy Plan, Hydro plans to keep the Holyrood TGS available through the Bridging Period until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. Beyond such time, the plan remains that Unit 3 at the Holyrood TGS would continue to operate as a SC, while Unit 1 and Unit 2 would be shut down and decommissioned.

In all scenarios, all three units at the Holyrood TGS are assumed to be available through the near-term study period (2025–2029).

3.2.2 Hardwoods and Stephenville Gas Turbines

The Stephenville GT consists of two 25 MW gas generators, commissioned in 1975. The Hardwoods GT consists of two 25 MW gas generators, commissioned in 1976. Each plant provides 50 MW of firm capacity to the system. These units were designed to operate in either generation mode to meet peak and emergency power requirements, or synchronous condense mode, to provide voltage support to the Island Interconnected System.

In the 2024 Resource Adequacy Plan, Hydro recommended continued investment in the Hardwoods GT and Stephenville GT during the Bridging Period to ensure reliable operation in support of the Island Interconnected System.

In all scenarios, both the Hardwoods GT and Stephenville GT are assumed to be available through the near-term study period (2025–2029).

3.3 2024 Load Forecast

3.3.1 Load Forecasting Process

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. This is a key input to the resource planning process, which ensures sufficient resources are available consistent with applied reliability standards. The load forecast is segmented by the Island Interconnected System, the Labrador Interconnected System, and rural isolated systems, as well as by utility load[42] and industrial load.[43] The load forecast process entails translating an economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. It also involves the development and analysis of potential new loads associated with electrification, (i.e., electric vehicle adoption forecasts and conversions of heating systems to electric heat). For the current analysis, Hydro has updated its provincial load forecast outlook to reflect the latest available load forecast information for its industrial customers, Newfoundland Power, and Hydro's own rural service territories.

3.3.2 Economic Setting

The Newfoundland and Labrador economy contracted (-2.1%) in 2023; however, most economic indicators showed moderate to strong growth. Total employment increased 1.8% in 2023 and the unemployment rate fell to 10%, the lowest annual rate since 1976. The provincial population also continues to experience strong growth, with an increase of 1.0% from April 2023 to April 2024. Capital investment continued to rebound from 2020 and 2021 levels, while housing starts were down 29% due to inflation and higher interest rates when compared to 2022. Other economic indicators, such as household disposable income, improved throughout the year.

Total oil production decreased by 13% compared to 2022; the value of oil production decreased by 27% due to lower production coupled with lower prices. Mineral shipments were down 18.6% from 2022, primarily due to lower nickel production at Voisey's Bay, lower nickel prices and lower prices for iron ore pellets. The seafood sector had a decrease in fish landings by 7.6% compared to 2022, and the value of landed catch declined by 44%. Aquaculture production saw an increase of 47% compared to 2022 and an increase of 72.4% in market value.

[42] Residential and General Service loads of Newfoundland Power and Hydro.
[43] Hydro currently has six Industrial customers on the Island and two Industrial customers in Labrador.

Looking forward through the medium term (i.e., one to five years) there are several developments that will positively influence provincial economic activity. The Terra Nova floating production storage and offloading vessel returned to production in November 2023 and production began at Braya Renewable Fuels' newly converted Come By Chance Refinery in February 2024, with around 18,000 barrels of renewable diesel per day expected. Several major projects (i.e., West White Rose, and hydrogen developments) should increase investment and contribute to employment gains. Further aquaculture developments proceeded in the province in 2023, with Grieg NL SeaFarms Ltd. beginning its first commercial harvest of farmed salmon in the fall of 2023. This company was also the successful proponent of the Bays West Aquaculture Development project and has begun the initial steps to develop the area. Continued increased interest in aquaculture is expected to expand the overall fishing and aquaculture industry.

The mining sector continues to have encouraging developments. Calibre Mining Corporation continues to advance its Valentine Gold Project in central Newfoundland, with the first production expected in the second quarter of 2025. Vale Newfoundland and Labrador ("Vale") has extended the mine life with the development of two underground mines at the Voisey's Bay Mine site. The first production from one of the underground mines occurred in 2021 and extraction from the second has begun. This project is a long-term source of nickel concentrate for the Long Harbour Processing Plant.

Over the medium term, real GDP is forecast to increase, primarily due to increased mineral production and investment growth. Most other economic indicators are also forecast to show growth. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that total oil production is expected to increase as the Terra Nova oil field gradually ramps up production after being offline for nearly three years. Mining activity is also expected to increase and remains a bright spot for medium-term growth. Non-residential activity in the near term will benefit further from the Bank of Canada's interest rate reduction cycle and will continue to contribute to positive economic growth.[44,45]

The current provincial outlook for 2024 continues to be positive. Underlying local market conditions for electric power operations through the medium and longer term, suggest significant increases in energy

[44] "Provincial Economic Forecast: Provincial Growth Looking Up As Interest Rates Come Down," TD Economics, June 19, 2024. https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_June2024.pdf.
[45] "Macroeconomic Outlook–Rate cuts won't spur immediate rebound in Canada's Economy," RBC Economics, June 12, 2024. https://thoughtleadership.rbc.com/rate-cuts-wont-spur-immediate-rebound-in-canadas-economy/.

requirements throughout the forecast period, which is partially driven by actions to combat climate change resulting in a shift towards electrification.[46]

3.3.3 Island Interconnected System Load Forecast

3.3.3.1 Reference Case

The Island Interconnected System Reference Case[47] peak demand forecast is provided in Table 3.

Table 3: Island Interconnected System Reference Case Demand Forecast (MW)[48]

	2025	2026	2027	2028	2029
Utility[49]	1,540	1,565	1,579	1,596	1,613
Industrial Customer	167	178	178	182	194
Customer Coincident Demand	**1,707**	**1,742**	**1,757**	**1,778**	**1,807**
Transmission Losses and Station Service[50]	55	56	57	58	59
Total Demand	**1,762**	**1,798**	**1,814**	**1,836**	**1,866**

Table 4 compares the current load forecast with the 2023 load forecast which was used in both the 2024 Resource Adequacy Plan and the November 2023 Near-Term Reliability Report.

Table 4: Comparison of Reference Case Peak Demand Forecasts (MW)[51]

	2025	2026	2027	2028	2029
2023 Customer Coincident Demand	1,725	1,736	1,753	1,772	1,809
2024 Customer Coincident Demand	1,707	1,742	1,757	1,778	1,807
Difference (MW)	**-18**	**+6**	**+4**	**+6**	**-2**
Difference (%)	**-1.0**	**+0.3**	**+0.2**	**+0.3**	**-0.1**

The 2024 Reference Case load forecast reflects minor changes in peak demand requirements through the study period as compared to the 2023 forecast.

[46] The energy outlook is conditioned by electricity prices in which the customer rate impacts of the Muskrat Falls Project are mitigated.
[47] Hydro's expected load forecast of firm electric power demand and energy requirements for the Island Interconnected System based upon the continuation of a steady level of decarbonization, driven primarily through government policy and programs, anticipated electrification of the transportation sector, and steady increase in population and housing starts.
[48] Numbers may not add due to rounding.
[49] The utility demand forecast includes approximately 22 MW of potential interruptible load starting in the fall of 2025.
[50] Excluding LIL losses.
[51] Before losses and station service loads.

3.3.3.2 Slow Decarbonization Case

The Island Interconnected System Slow Decarbonization Case[52] peak demand forecast is provided in Table 5.

Table 5: Island Interconnected System Slow Decarbonization Case Peak Demand Forecast (MW)[53]

	2025	2026	2027	2028	2029
Utility[54]	1,539	1,561	1,570	1,580	1,593
Industrial Customer	167	178	178	178	189
Customer Coincident Demand	**1,706**	**1,739**	**1,747**	**1,758**	**1,782**
Transmission Losses and Station Service	55	56	57	57	58
Total Demand	**1,761**	**1,795**	**1,804**	**1,815**	**1,840**

Table 6 compares the current Slow Decarbonization load forecast with the 2023 Slow Decarbonization load forecast which was used in the 2024 Resource Adequacy Plan.

Table 6: Comparison of Slow Decarbonization Case Peak Demand Forecasts (MW)[55]

	2025	2026	2027	2028	2029
2023 Customer Coincident Demand	1,716	1,722	1,733	1,744	1,774
2024 Customer Coincident Demand	1,706	1,739	1,747	1,758	1,782
Difference (MW)	**-10**	**+17**	**+14**	**+14**	**+8**
Difference (%)	**-0.6**	**+1.0**	**+0.8**	**+0.8**	**+0.5**

The 2024 Slow Decarbonization load forecast reflects minor changes in peak demand requirements through the study period as compared to the 2023 forecast.

3.4 System Energy Capability

Hydro maintains minimum system storage limits to ensure that it can meet customer energy requirements given a repeat of its critical dry sequence[56] and any shorter-term dry periods in the hydrological record. These limits represent the point at which thermal generation would need to be dispatched to support reservoir storage and to ensure customer requirements could be met. The 2024–

[52] Hydro's Island Interconnected System Slow Decarbonization Case considers more moderate decarbonization efforts and electrification of the transportation sector, lower population and housing starts, resulting in a lower load forecast as compared to the Reference Case.
[53] Numbers may not add due to rounding.
[54] The utility demand forecast includes approximately 22 MW of potential interruptible load in fall 2025.
[55] Before losses and station service loads.
[56] Hydro's long-term critical dry sequence is defined as January 1959 to March 1962 (39 months).

2025 limits were developed using the Vista Model and assuming maximum imports over the LIL. The limits are developed assuming no imports over the Maritime Link as discussed in Section 3.5.

Regular assessments of storage at each of Hydro's large storage reservoirs are completed and operations are modified as needed to ensure that each hydraulic generating unit remains capable of producing at full-rated output through the winter period. At this time, Hydro does not foresee using production from standby generation to support reservoir levels.

At the end of October 31, 2024, the total system energy in storage was 1,491 GWh, 229 GWh above the minimum storage limit of 1,262 GWh for October 2024.

Chart 1 plots the 2023 and 2024 storage levels, the maximum operating level storage, the minimum storage limit, and the 20-year average aggregate storage for comparison.

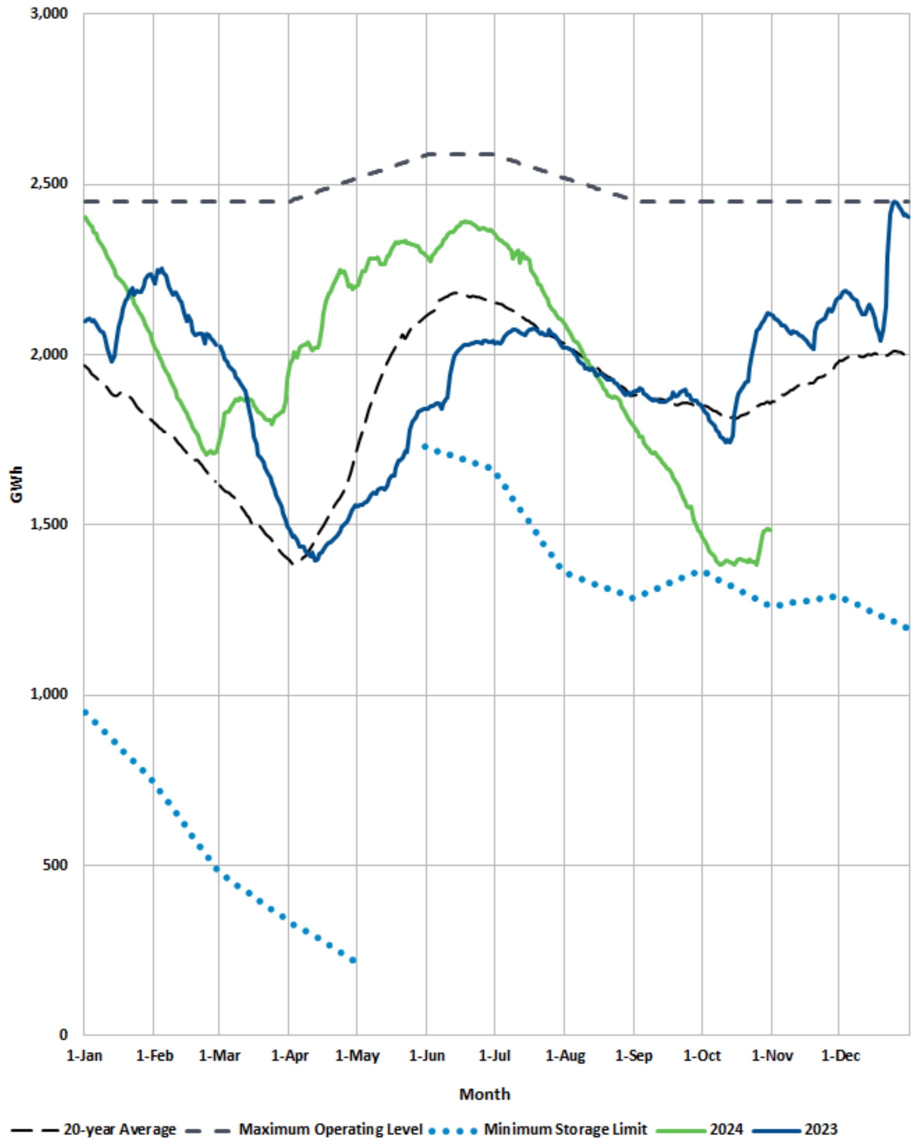

Chart 1: Total System Energy Storage

3.5 Availability of Imports

Firm imports over the Maritime Link could contribute to the reliability of the Island Interconnected System; however, Hydro does not consider imports over the Maritime Link to be a feasible option. Transmission paths to gain access to potential markets are largely committed, and neighbouring jurisdictions do not have surplus capacity to export. Each of these items is discussed in the following sections.

3.5.1 Transmission and Market Access

The Island Interconnected System has access to three potential markets when considering firm imports via the Maritime Link—Nova Scotia, New Brunswick, and New England. A summary of these options from a transmission perspective follows:

1) **Nova Scotia**: To acquire energy from Nova Scotia, Hydro requires only its existing Maritime Link transmission access as Nova Scotia Power has the ability to deliver energy to the Nova Scotia-Newfoundland and Labrador border.

2) **New Brunswick**: To acquire energy from New Brunswick, two transmission paths need to be considered—New Brunswick and Nova Scotia transmission.
   - The transmission path inside New Brunswick to deliver energy to Nova Scotia shares the interface between New Brunswick and Prince Edward Island. New Brunswick has firm contracts to supply firm energy and balance the load in Prince Edward Island. The transmission interface limit is 300 MW and the firm transmission is contracted by New Brunswick to meet their contractual obligations to Prince Edward Island.
   - The interface between the New Brunswick/Nova Scotia transmission system is often congested. However, in December 2023, Nova Scotia Power Inc. ("NS Power") received environmental approval[57] from the Nova Scotia government for the construction of a new 345-kilovolt transmission line twinning the existing line to the New Brunswick border. This new transmission line is expected to significantly increase the amount of capacity between New Brunswick and Nova Scotia. NS Power is estimating a 2028 completion date. Hydro will continue to monitor the progress of this transmission line and its potential impacts on the possibility of acquiring firm capacity.

3) **New England**: To acquire energy from the New England market, the two transmission paths across New Brunswick and Nova Scotia need to be considered, with the limitations noted previously. The export path from the New England market is limited by the New Brunswick/Nova Scotia interface. Additionally, the transmission interface between New Brunswick and the New England market can become congested. New Brunswick Power Corporation ("NB Power") has priority at that interface for imports for their native load.

[57] "NS-NB Reliability Intertie Project," Government of Nova Scotia. https://www.novascotia.ca/nse/ea/ns-nb-reliability-intertie/.

It is important to note that there are also Island transmission constraints in delivering imported energy via the Maritime Link to the Avalon Peninsula.[58]

3.5.2 Availability of Surplus Firm Capacity

The other consideration is firm capacity availability from each of the aforementioned markets. A summary follows:

- **Nova Scotia**: According to the 2023 Evergreen Integrated Resource Plan,[59] NS Power continues to plan to retire coal by 2030 and does not have surplus capacity in their system to export. NS Power heavily relies on coal to meet its capacity requirements in the winter and is looking to replace its coal plants with a total capacity of 1,081 MW by 2030 to meet federal government regulations.
- **New Brunswick**: NB Power filed a ten-year Integrated Resource Plan in 2023,[60] at which time it outlined the requirement to build additional capacity to meet load growth and decarbonization plans. In June 2024, NB Power issued a request for expression of interest for a 400 MW natural gas plant as a potential option to meet earlier than planned load growth.
- **New England**: The market in New England has an annual forward capacity market auction. Each auction determines the capacity market for the fourth year out in the future. Considering the long lead time to build the required capacity in Newfoundland and Labrador, this capacity market planning horizon is not compatible with the planning requirements for the reliability of the Island Interconnected System.

In August 2024, Hydro confirmed with both NS Power and NB Power that acquiring a firm import contract during the winter period for reliability is not feasible for either utility in the near term. However, the potential markets and constraints will continue to be assessed annually. This confirmation does not preclude opportunities on a short-term (spot market) basis for firm capacity or non-firm energy to meet capacity or energy requirements for the Island Interconnected System.

[58] Please refer to 2024 Resource Adequacy Plan, app. B, sec. 5.4.1.1, pp. 51–53.
[59] "Powering A Green Nova Scotia, Together – 2023 Evergreen Integrated Resource Plan – Updated Action Plan and Roadmap," Nova Scotia Power Inc., August 8, 2023. https://www.nspower.ca/irp.
[60] "2023 Integrated Resource Plan – Pathways to a Net-Zero Electricity System," New Brunswick Power Corporation. https://www.nbpower.com/media/1492536/2023_irp.pdf.

3.6 Capacity Assistance Contracts

3.6.1 Vale Capacity Assistance Agreement

For all scenarios, it is assumed that the contract for 7.6 MW of capacity assistance with Vale is renewed for each winter season in the study period. The rationale is that if Hydro was in a loss of load situation, these existing diesel units could provide capacity assistance. Hydro is working with Vale on a capacity assistance agreement for the 2024–2025 winter operating season,.

3.6.2 CBPP Capacity Assistance Agreement

In Board Order No. P.U. 32(2023), the Board approved a Capacity Assistance Agreement between CBPP and Hydro, through which CBPP agreed to provide Hydro with up to 90 MW of capacity assistance in the winter period, and 50 MW in the summer period, for a 15-year term. In all scenarios, it is assumed that the CBPP Capacity Assistance Agreement remains in place throughout the study period.

3.6.3 Memorial University Capacity Assistance Agreement

The 2024 load forecast includes Memorial University's ("MUN") electric boiler (approximately 22 MW of load) entering service in the summer of 2025. MUN plans to retain its oil boiler as backup and, when required, will be able to run its oil boiler instead of the new electric boiler. Newfoundland Power and MUN are currently in discussion on a capacity assistance agreement which would make the generation from the oil boiler available to the grid during system needs. The intention is to have this agreement in place for winter 2025–2026.

3.6.4 Newfoundland Power Curtailable Credit

In Board Order No. P.U. 49(2016), the Board approved the use of the Curtailable Credit on a final basis. The Curtailable Credit ensures that curtailments are requested from Newfoundland Power customers only to meet system load requirements. Previously, curtailments were also requested to reduce the demand requirements of the company during peak load conditions. In accordance with Hydro's Utility rate, the Curtailable Credit is required to be verified annually. Newfoundland Power's Curtailment Credit from Hydro is 12 MW on a monthly billing basis.

3.7 Scenarios and Sensitivities

Five scenarios were analyzed to assess system reliability under a range of potential system conditions:

- **Scenario 1 (Reference Case):** Assumes that the LIL will be available at 700 MW for the study period with a 5% bipole FOR. This case assumes a DAUFOP of 20% for the Holyrood TGS and the 2024 Reference Case load forecast.
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS FOR to the 2021 actual of 34%.
- **Scenario 3**: Varies from Scenario 1 by increasing the bipole FOR to 10% through the study period.
- **Scenario 4**: Varies from Scenario 1 by decreasing the bipole FOR to 1% through the study period.
- **Scenario 5:** Varies from Scenario 1 by considering the 2024 Slow Decarbonization load forecast rather than the 2024 Reference Case load forecast.

Four sensitivity scenarios were also analyzed. These scenarios were based on Scenario 1 (Reference Case) with modifications as follows:

- **Scenario 1A:** Assumes Holyrood TGS Unit 1 is unavailable for the winter 2024–2025.
- **Scenario 1B:** Assumes the LIL bipole capacity is increased to 900 MW.
- **Scenario 1C:** Assumes the LIL bipole capacity is reduced to 450 MW.
- **Scenario 1D:** Assumes Holyrood TGS Unit 3 is retired at the end of 2028, and a new 150 MW CT plant[61] coming online at the beginning of 2029.

4.0 Results

The following subsections provide a description of the metrics used to quantify reliability in this analysis along with the results, with Section 4.1 summarizing the results of Scenarios 1 to 5 and Section 4.2 summarizing the results of the Scenario 1 sensitivities.

[61] Modeled as three new 47 MW CTs.

Results of the near-term reliability analysis are presented in terms of three different reliability metrics, together providing information on the duration and magnitude of insufficient supply. LOLH and EUE are reported on an annual and monthly basis, and NEUE is reported on an annual basis.

4.1 Scenarios 1 to 5

The results of the near-term reliability analysis of Scenarios 1 to 5 are summarized and discussed on annual and monthly time frames in the following sections.

4.1.1 Annual Results

Annual LOLH, EUE, and NEUE results for Scenarios 1 to 5 are provided in Table 7. Hydro's probabilistic capacity planning criteria specify that the Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.[62] LOLH results above this threshold are highlighted in bold red text.

Table 7: Scenarios 1 to 5 Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2025	2026	2027	2028	2029
Scenario 1: Reference Case	2.0	1.1	1.2	1.3	2.0
Scenario 2: Holyrood TGS DAUFOP = 34%	**4.8**	**3.1**	**3.3**	**3.6**	**5.2**
Scenario 3: LIL Bipole FOR = 10%	**3.9**	2.1	2.3	2.5	**3.8**
Scenario 4: LIL Bipole FOR = 1%	0.5	0.3	0.3	0.3	0.5
Scenario 5: Slow Decarbonization load	2.0	1.0	1.0	1.0	1.4

EUE (MWh)	2025	2026	2027	2028	2029
Scenario 1: Reference Case	140	70	80	90	150
Scenario 2: Holyrood TGS DAUFOP = 34%	360	230	250	280	420
Scenario 3: LIL Bipole FOR = 10%	280	140	160	180	280
Scenario 4: LIL Bipole FOR = 1%	40	20	20	20	30
Scenario 5: Slow Decarbonization load	140	70	70	70	100

NEUE (ppm)[63]	2025	2026	2027	2028	2029
Scenario 1: Reference Case	17	8	9	10	17
Scenario 2: Holyrood TGS DAUFOP = 34%	43	27	29	32	48
Scenario 3: LIL Bipole FOR = 10%	33	16	19	21	32
Scenario 4: LIL Bipole FOR = 1%	5	2	2	2	3
Scenario 5: Slow Decarbonization load	17	8	8	8	11

[62] LOLH is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity.
[63] NEUE, given here in ppm, represents lost load as a fraction of total system load. NERC recommends system operators consider NEUE a reliability metric; however, a single target threshold has not been set. Different jurisdictions use targets ranging from 10 ppm to 30 ppm.

In Scenario 1 (Reference Case), the LOLH remains below Hydro's planning criteria of 2.8 LOLH for all years. In Scenario 2 where the Holyrood TGS FOR is increased to 34%, the planning criteria is exceeded in each year. In Scenario 3, the LIL EqFOR is doubled from the 5% Reference Case, and this leads to criteria exceedance in two of the five years studied. Scenario 4 assumes a low LIL EqFOR of 1% and leads to LOLH below the criteria in all years. In Scenario 5, the LOLH remains below Hydro's planning criteria of 2.8 LOLH for all years.

4.1.2 Monthly Results

Table 8 to Table 12 provide LOLH and EUE for each year by month for Scenarios 1 to 5. The monthly results provide additional detail that assists in examining the complexity of the changing power system that would not necessarily be apparent from an analysis of the annual results only. Completing monthly analysis allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for a better understanding of the drivers of the annual results. This type of analysis is used by NERC-regulated utilities to complement long-term reliability assessments.

Table 8: Scenarios 1 to 5 Monthly LOLH and EUE for 2025[64]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	1.2	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Holyrood TGS DAUFOP = 34%	2.2	1.0	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Scenario 3: LIL Bipole FOR = 10%	2.2	0.7	0.7	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2
Scenario 4: LIL Bipole FOR = 1%	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: Slow Decarbonization load	1.1	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	80	20	30	0	0	0	0	0	0	0	0	0
Scenario 2: Holyrood TGS DAUFOP = 34%	180	70	80	10	0	0	0	0	0	0	10	20
Scenario 3: LIL Bipole FOR = 10%	170	40	50	0	0	0	0	0	0	0	0	10
Scenario 4: LIL Bipole FOR = 1%	20	10	10	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Decarbonization load	80	20	30	0	0	0	0	0	0	0	0	0

[64] Monthly results may not add up to annual results due to rounding.

Table 9: Scenarios 1 to 5 Monthly LOLH and EUE for 2026[65]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Holyrood TGS DAUFOP = 34%	1.3	1.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 3: LIL Bipole FOR = 10%	0.9	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 4: LIL Bipole FOR = 1%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: Slow Decarbonization load	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 2: Holyrood TGS DAUFOP = 34%	100	90	20	0	0	0	0	0	0	0	0	20
Scenario 3: LIL Bipole FOR = 10%	60	50	10	0	0	0	0	0	0	0	0	10
Scenario 4: LIL Bipole FOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Decarbonization load	30	30	10	0	0	0	0	0	0	0	0	10

Table 10: Scenarios 1 to 5 Monthly LOLH and EUE for 2027[66]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Holyrood TGS DAUFOP = 34%	1.4	1.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 3: LIL Bipole FOR = 10%	1.0	0.9	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 4: LIL Bipole FOR = 1%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: Slow Decarbonization load	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 2: Holyrood TGS DAUFOP = 34%	110	90	30	0	0	0	0	0	0	0	0	20
Scenario 3: LIL Bipole FOR = 10%	70	60	20	0	0	0	0	0	0	0	0	10
Scenario 4: LIL Bipole FOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Decarbonization load	30	30	10	0	0	0	0	0	0	0	0	10

[65] Monthly results may not add up to annual results due to rounding.
[66] Monthly results may not add up to annual results due to rounding.

Table 11: Scenarios 1 to 5 Monthly LOLH and EUE for 2028[67]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1:Reference Case	0.6	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Holyrood TGS DAUFOP = 34%	1.6	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 3: LIL Bipole FOR = 10%	1.2	0.8	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 4: LIL Bipole FOR = 1%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: Slow Decarbonization load	0.5	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 2: Holyrood TGS DAUFOP = 34%	130	80	30	0	0	0	0	0	0	0	0	30
Scenario 3: LIL Bipole FOR = 10%	90	60	20	0	0	0	0	0	0	0	0	20
Scenario 4: LIL Bipole FOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Decarbonization load	30	20	10	0	0	0	0	0	0	0	0	10

Table 12: Scenarios 1 to 5 Monthly LOLH and EUE for 2029[68]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 2: Holyrood TGS DAUFOP = 34%	2.0	1.8	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Scenario 3: LIL Bipole FOR = 10%	1.6	1.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 4: LIL Bipole FOR = 1%	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 5: Slow Decarbonization load	0.6	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	60	50	20	0	0	0	0	0	0	0	0	10
Scenario 2: Holyrood TGS DAUFOP = 34%	170	150	50	0	0	0	0	0	0	0	0	50
Scenario 3: LIL Bipole FOR = 10%	120	100	30	0	0	0	0	0	0	0	0	30
Scenario 4: LIL Bipole FOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Decarbonization load	40	40	10	0	0	0	0	0	0	0	0	10

The monthly results show the expected result that most of the loss of load hours and expected unserved energy occur in the month of January when the load is at its highest. Some loss of load events also occur in December, February and March with very few loss of load events in other months.

[67] Monthly results may not add up to annual results due to rounding.
[68] Monthly results may not add up to annual results due to rounding.

4.2 Scenario 1 Sensitivities

4.2.1 Annual Results

Annual LOLH, EUE and NEUE results for Scenario 1 sensitivities are provided in Table 13. Hydro's probabilistic capacity planning criteria specify that the Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year. LOLH Results above this threshold are highlighted in bold red text.

Table 13: Scenario 1 Sensitivities Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2025	2026	2027	2028	2029
Scenario 1: Reference Case	2.0	1.1	1.2	1.3	2.0
Scenario 1A: HRD[69] Unit 1 out of service for Winter 2024-2025	**4.1**	1.1	1.2	1.3	2.0
Scenario 1B: LIL at 900 MW	2.0	1.1	1.2	1.3	1.9
Scenario 1C: LIL at 450 MW	2.5	1.3	1.4	1.6	2.6
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	2.0	1.1	1.2	1.3	1.2

EUE (MWh)	2025	2026	2027	2028	2029
Scenario 1: Reference Case	140	70	80	90	150
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	290	70	80	90	150
Scenario 1B: LIL at 900 MW	140	70	80	90	140
Scenario 1C: LIL at 450 MW	160	80	90	110	170
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	140	70	80	90	80

NEUE (ppm)[70]	2025	2026	2027	2028	2029
Scenario 1: Reference Case	17	8	9	10	17
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	35	8	9	10	17
Scenario 1B: LIL at 900 MW	17	8	9	10	16
Scenario 1C: LIL at 450 MW	19	9	11	13	19
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	17	8	9	10	9

Scenario 1A results above indicate that if HRD Unit 1 were to remain out of service for the full winter of 2024–2025, the risk of having a loss of load event doubles for the year 2025. The results in other years are unchanged from Scenario 1 since there was no change in inputs for those years.

Scenario 1B results above indicate that the influence of increasing the LIL bipole capacity to 900 MW has very little influence on the reliability of the Island Interconnected System. This result is expected since the modelled loss of load events is almost always due to a LIL bipole outage, so the capacity of the

[69] Holyrood ("HRD").
[70] NEUE, given here in ppm, represents lost load as a fraction of total system load. NERC recommends system operators consider NEUE a reliability metric; however, a single target threshold has not been set. Different jurisdictions use targets ranging from 10 ppm to 30 ppm.

interconnection is not as relevant to system reliability. Also, the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island Load, so increasing the LIL bipole capacity does not have an impact on reliability metrics.

Reducing the LIL bipole capacity (Scenario 1C) however does negatively influence the expected reliability of the Island Interconnected System, though LOLH remains below the planning criteria value of 2.8 in every year of the study period.

Scenario 1D tests the influence of retiring Holyrood TGS Unit 3 at the end of 2028 and integrating a new 150 MW CT plant[71] at the beginning of 2029. This has reliability benefits in 2029 because the FOR assumption for the new CTs is 4.9% compared to 20% for HRD Unit 3. Additionally, having multiple smaller units has reliability benefits over having one larger unit, even if the total capacity is the same.

4.2.2 Monthly Results

Table 14 to Table 18 provide LOLH and EUE for each year by month for Scenario 1 sensitivities.

Table 14: Scenario 1 Sensitivities Monthly LOLH and EUE for 2025[72]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	1.2	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	1.4	1.3	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1B: LIL at 900 MW	1.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: LIL at 450 MW	1.5	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	1.2	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	80	20	30	0	0	0	0	0	0	0	0	0
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	100	90	100	0	0	0	0	0	0	0	0	10
Scenario 1B: LIL at 900 MW	90	20	30	0	0	0	0	0	0	0	0	0
Scenario 1C: LIL at 450 MW	100	20	30	0	0	0	0	0	0	0	0	10
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	80	20	30	0	0	0	0	0	0	0	0	0

[71] Modeled as three new 47 MW CTs.
[72] Monthly results may not add up to annual results due to rounding.

Table 15: Scenario 1 Sensitivities Monthly LOLH and EUE for 2026[73]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1B: LIL at 900 MW	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: LIL at 450 MW	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 1B: LIL at 900 MW	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 1C: LIL at 450 MW	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	30	30	10	0	0	0	0	0	0	0	0	10

Table 16: Scenario 1 Sensitivities Monthly LOLH and EUE for 2027[74]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1B: LIL at 900 MW	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: LIL at 450 MW	0.6	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1B: LIL at 900 MW	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 1C: LIL at 450 MW	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	40	30	10	0	0	0	0	0	0	0	0	10

[73] Monthly results may not add up to annual results due to rounding.
[74] Monthly results may not add up to annual results due to rounding.

Table 17: Scenario 1 Sensitivities Monthly LOLH and EUE for 2028[75]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.6	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	0.6	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1B: LIL at 900 MW	0.6	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: LIL at 450 MW	0.8	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	0.6	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1B: LIL at 900 MW	40	30	10	0	0	0	0	0	0	0	0	10
Scenario 1C: LIL at 450 MW	50	30	10	0	0	0	0	0	0	0	0	10
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	40	30	10	0	0	0	0	0	0	0	0	10

Table 18: Scenario 1 Sensitivities Monthly LOLH and EUE for 2029[76]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	0.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1B: LIL at 900 MW	0.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1C: LIL at 450 MW	1.1	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	60	50	20	0	0	0	0	0	0	0	0	10
Scenario 1A: HRD Unit 1 out of service for Winter 2024-2025	60	50	20	0	0	0	0	0	0	0	0	10
Scenario 1B: LIL at 900 MW	60	50	10	0	0	0	0	0	0	0	0	10
Scenario 1C: LIL at 450 MW	80	60	20	0	0	0	0	0	0	0	0	20
Scenario 1D: HRD Unit 3 retires end of 2028, new 150 MW CT plant in 2029	30	30	10	0	0	0	0	0	0	0	0	10

Again, the monthly results indicate that the highest reliability risk occurs in January when the load is highest, with lesser reliability risk in December, February and March. There were no loss of load events experienced in the summer months for any of the Scenario 1 sensitivities.

[75] Monthly results may not add up to annual results due to rounding.
[76] Monthly results may not add up to annual results due to rounding.

5.0 Conclusion

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. Scenario 1 (Reference Case) is what Hydro expects to occur in the near term. To ensure that it has a fulsome understanding of the system reliability under a range of potential future scenarios, Hydro has analyzed the impact of several key factors impacting near-term reliability including FORs, load forecasts and extended planned outages among other factors, which are reflected in the scenarios and sensitivity analysis.

Hydro expects reliable system operation for the coming winter season. The results of Scenario 1 (Reference Case) suggest an acceptable level of reliability through the study period based on Hydro's planning criteria of 2.8 LOLH per year. Exceedance of the planning criteria occurs in all years if the Holyrood TGS experiences a higher-than-expected FOR of 34% (Scenario 2). In Scenario 3, if the LIL experiences a FOR of 10% or higher, the results show that the planning criteria is exceeded in some years as is the case as well with Scenario 1A, where the HRD Unit 1 outage extends through the full winter of 2024–2025. It is important to note that exceeding the planning criteria does not necessarily mean an outage will occur; Hydro uses the results of its near-term planning to measure and evaluate evolving risks to ensure the reliability of the system in tandem with delivering environmentally responsible power, consistent with the lowest cost.

As identified in the results, the EqFOR of the LIL remains essential to system reliability.[77] Heading into the 2024–2025 winter operating season, subject to the completion of high-power testing, the LIL would be available at its full nameplate rating of 900 MW.[78] As per the November 2024–2025 Winter Readiness Planning Report,[79] work continues on various capital projects, including tower modifications, to address prior issues on the LIL. The Turnbuckles Replacement and Airflow Spoiler Installation Program is progressing with 98% of turnbuckles to be completed by the end of 2024, and 74% of air spoilers having been installed to date. The remaining work in this program will be completed in 2025. DCCT replacement to address cold weather-related issues is in progress with completion expected in 2025.

[77] Until there have been multiple years of operational experience for the LIL to better inform the selection of a bipole FOR, the LIL bipole FOR will be addressed with a range of upper and lower limits. As the LIL performance statistics become available in the coming years, the bipole FOR range can be narrowed in future filings.
[78] The LIL is currently available to operate up to 700 MW.
[79] "2024–2025 Winter Readiness Planning Report," Newfoundland and Labrador Hydro, November 12, 2024.

The results also show that the availability of generation assets is another important factor in maintaining system reliability. Hydro continues to monitor and address factors that may affect generating unit reliability across all of its assets. Hydro recognizes that the forced unavailability of Unit 1 at the Holyrood TGS until mid-January 2025 will put an additional strain on the system; however, Hydro is actively working towards returning this unit to service earlier than what has been assumed in the scenario analysis.

To help ensure reliable service for customers in the near term, Hydro has committed to maintaining the Holyrood TGS, the Hardwoods GT, and the Stephenville GT as generating facilities until new generation can be integrated into the system. Hydro is actively working towards advancing new supply options; however, it is expected that new generation options will not be available until 2029–2031, at the earliest. As additional support for system reliability, Hydro is also working on a capacity assistance agreement with Vale in advance of the coming winter. Firm imports would not be available on a consistent basis due to generation and transmission restrictions in neighbouring jurisdictions and internal system limitations. However, in some cases, opportunities may be available on a short-term (spot-market) basis to meet capacity or energy requirements for the Island Interconnected System, should they be required. This reinforces the importance of maintaining existing generation and transmission assets in order to minimize outages.

Hydro remains focused on the completion of its annual maintenance program to ensure the reliability of its existing assets in advance of the 2024–2025 winter operating season as well as monitoring the health of the assets to ensure continued, reliable, least-cost supply for customers.