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November 20, 2025

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* – 2025 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 2025 Near-Term Reliability Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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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

2025 Near-Term Reliability Report

November 20, 2025

A report to the Board of Commissioners of Public Utilities

Executive Summary

Supply adequacy remains a critical priority for Newfoundland and Labrador Hydro ("Hydro") and its stakeholders. This report provides a detailed assessment of near-term system risks and outlines mitigation measures to ensure customer demand is met reliably, while delivering environmentally responsible power consistent with least-cost principles.

Overall, Hydro's load forecasting for 2025 has resulted in only minor changes compared to its 2024 forecast. Increases to peak demand continue to be projected year-over-year through 2030, driven by economic activity in the mineral, aquaculture, and oil sectors, as well as growing electrification.

To evaluate reliability, Hydro applied established planning criteria across five scenarios. The scenarios include the presentation of a Reference Case representing expected system conditions, as well as four other scenarios, including a lower-demand "Slow Electrification" forecast; improved reliability of the Labrador-Island Link ("LIL") through reduced bipole equivalent forced outage rates ("EqFOR") of 3% and 1%; and consideration of a lower-demand "Slow Electrification" forecast with high LIL reliability.

As well, Hydro also considers three sensitivity scenarios with varying system constraints to further assess the effects on reliability for the Reference Case. These include increased forced outage rate ("FOR") for the Holyrood Thermal Generating Station ("Holyrood TGS"); increased LIL bipole capacity; and the potential for continued unavailability of Holyrood TGS Unit 3 for the winter of 2025–2026.

The results of the in-depth analysis indicate that Hydro will meet the planning criteria in the Reference Case throughout the 2026 to 2030 period. There is, however, a sensitivity scenario where system conditions could result in exceeding reliability criteria, such as if the Holyrood TGS experienced a FOR of 34%. Other scenarios, including the continued unavailability of Holyrood TGS Unit 3 for the 2025–2026 winter season, show elevated risk in January 2026 but remain within the planning threshold. 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 continues to closely monitor its supply-related assets to ensure reliable service, and remains committed to ensuring existing generating assets are in good condition until new generation can be approved, constructed, and reliability integrated into the Island Interconnected System. Through continued maintenance of its existing fleet, targeted capital investments, and the integration of new resources, Hydro is positioned to deliver reliable, least-cost and environmentally responsible electricity to customers for the upcoming winter and near-term period.

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 presents the results of a probabilistic resource adequacy assessment for the Island Interconnected System, evaluating near-term reliability over the 2026 to 2030 study period.[1] As outlined in the 2024 Resource Adequacy Plan,[2] the Labrador Interconnected System continues to exhibit 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 loss of load hours ("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 was considered for the Holyrood TGS and the LIL.[5]

2.0 Asset Reliability

Hydro files its quarterly Rolling 12 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

[1] The study period concludes at the end of April 2030, which is the assumed retirement date of Holyrood TGS in the model.
[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.
[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 EqFORs was considered, consistent with the analysis conducted in the 2024 Resource Adequacy Plan and the "Reliability and Resource Adequacy Study Review - 2024 Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 20, 2024 ("November 2024 Near-Term Report").
[6] Hydro's Quarterly Report on Asset Performance in Support of Resource Adequacy ("Rolling 12 Report") 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. The 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 Rolling 12 Report was submitted on October 31, 2025.[8]

Hydro has reviewed the factors affecting generating unit reliability since the November 2024 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 2024 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 related to both asset condition and asset type 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, issues have been identified as either resolved, requiring continued monitoring, ongoing or new, and are grouped by facility type as follows:

- Hydraulic;
- Holyrood TGS;
- Combustion Turbines ("CT"); and
- Muskrat Falls Generating Facility/LIL.

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.

[8] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2025," Newfoundland and Labrador Hydro, October 31, 2025.

2.1 Hydraulic

2.1.1 Resolved Issues

2.1.1.1 Bay d'Espoir Unit 7 Generator Bearing Coolers

As previously reported,[9] Bay d'Espoir Unit 7 experienced leaks in the generator bearing coolers following the scheduled outage in 2024 as a result of tube failures. To enable the unit to return to service in August 2024, Hydro used two available spares from inventory and reassembled the remaining two coolers using the undamaged tubes from all four coolers. In late 2024, Hydro procured and installed two new coolers to replace the reassembled coolers. As the unit has operated without issue since the installation of the new coolers, Hydro considers this issue resolved.

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.[10] 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.[11] 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), and completion of construction is anticipated in early December 2025.[12]

Penstock 2 was inspected in May 2025; during the inspection, two new indications were discovered and repaired. Four indications discovered in 2024, which posed no material concerns at that time, were also repaired during the 2025 inspection. Penstock 3 was inspected in November 2025. Some indications

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[9] "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.
[10] These reports were filed with the Board in "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.
[11] The failure analysis and engineering review results were filed with the Board in "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.
[12] Based on the construction completion date, Units 1 and 2 are anticipated to return to service in mid-December. Project closeout is expected to be in the first quarter of 2026 to provide sufficient time for final billings, commissioning and general project documentation handover to occur.

were discovered, which pose no material concerns and do not require repair at this time. As a result, there are no immediate concerns with the condition of either penstock. Hydro will continue with the annual inspection program until such a time that the necessary life extension work has been completed.

Modifications to the automatic generator control application in Hydro's Energy Management System remain in place, designed to limit the amount of rough zone operation, as well as a more prescriptive operating regime for Units 5 and 6 due to the results of annual inspections of Penstock 3 in recent years. In this operating regime, Units 5 and 6 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. In previous years, operational modifications were in place on Penstock 1 (i.e., Units 1 and 2); however, these modifications will no longer be required after capital investment is completed in 2025.

Although Hydro has mitigated the risk of failure to the extent possible, there is a residual risk that a failure could occur on Penstocks 2 or 3[13] before further life extension work is completed. Hydro has estimated a 13- to 23-day repair timeline, depending on the circumstances, should a new failure occur, and has continued to take proactive measures to reduce generating unit downtime, including maintaining an inventory of pre-rolled steel plates and confirming the availability of local welding resources.

Hydro will provide an update on this issue in the 2026 Near-Term Report.

2.1.2.2 Hinds Lake Unit Vibration and Shaft Seal Leakage

Since the filing of the November 2024 Near-Term Report, the unit has continued to experience higher-than-normal vibration levels and shaft seal leakage rates. Hydro has continued to monitor both issues. The unit is currently offline, undergoing preventative and corrective maintenance activities aimed at assessing and improving these issues, the results of which will be discussed in Hydro's next 2025–2026 Winter Readiness Planning Report to be filed on December 10, 2025. It is anticipated that the Hinds Lake Unit will be available at full capacity this coming winter.

2.1.2.3 Upper Salmon Unit Turbine Seal Clearances

As reported in the 2024 Near-Term Report, during the execution of approved capital work in 2023, Hydro successfully adjusted the position of the rotating components of the unit relative to the stationary

[13] Life extension projects for Penstock 3 and Penstock 2 are currently planned for 2027 and 2030, respectively.

seals to improve the clearances at both the upper and lower turbine seals. Hydro notes that the clearance is still below the recommended intervention limit as recommended by the Centre for Energy Advancement through Technological Innovation; however, the adjustment provided a significant improvement over the as-found values from 2023. 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. Seal clearance measurements were completed in October 2024 and again in September 2025, and have resulted in minimal change in clearances at this time.

Hydro will continue to monitor this issue.

2.2 Holyrood TGS

2.2.1 Resolved Issues

2.2.1.1 Variable Frequency Drives

Forced draft fans provide the combustion air required for boiler operation at the Holyrood TGS. The Variable Frequency Drives ("VFDs") were installed to more efficiently vary the amount of air supplied based on generation needs; however, Hydro has dealt with reliability issues related to this equipment since its installation.

During the 2024 outage season, Hydro completed the bypass of the VFDs on Unit 1. The unit was returned to service without VFDs on the forced draft fans for the 2024–2025 winter operating season,[14] and the fans have operated reliably since. With VFDs now bypassed on all three units at the Holyrood TGS, Hydro considers this issue resolved.

2.2.1.2 Unit 1 and Unit 2 Turbine Blades

In 2021, cracks were found in the Last Stage Blades ("LSBs") 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.

[14] The unit did not return to service until May 2025 due to the forced extension of the planned turbine overhaul, which was required to restore the bearing journals on the turbine rotor. The fans were operated periodically, for commissioning, between February and May 2025. There were no issues with the forced draft fans during this time.

Hydro replaced the LSBs and second LSBs on the Unit 2 rotor in 2023 and on Unit 1 in 2024.[15] Unit 2 was returned to service in April 2024, after commissioning. Since returning to service, shaft vibration has been elevated but acceptable for long-term continuous operation. There are no operational concerns, and the unit is stable and released for service. Unit 1 was returned to service in May 2025 with no operational concerns related to the replacement of the blades. Hydro considers this issue to be resolved.

2.2.1.3 Unit 2 and 3 Boiler Feed Pump Gland Seal Strainers

Gland seal strainers are designed to remove debris from the injected water and prevent the debris from entering the boiler feed pump glands, where it could cause damage to the pump. The strainers are designed so that they can be cleaned without taking the boiler feed pumps out of service.

The Unit 1 gland seal strainer was replaced in 2024, but the late delivery of the strainers prevented the replacement of Unit 2 and Unit 3 strainers. The gland seal strainers on Units 2 and 3 were replaced in 2025. Hydro considers this issue to be resolved.

2.2.1.4 Unit 2 Condenser Derating

Towards the end of the 2024–2025 operating season, Unit 2 was derated to 115 MW due to high condenser back-pressure. The derating began on April 21, 2025. After returning the unit to service following a maintenance outage to complete an air heater wash, high backpressure in the condenser prevented the unit from exceeding 115 MW. Operations attempted a condenser back-wash, but the problem persisted, and it was determined that Unit 2 would require an outage to correct the derating. This derating remained until the unit was taken offline and began its planned annual outage in June 2025.

During the planned outage, heavy fouling of the condenser on Unit 2 was discovered. Extensive cleaning of the condenser was completed during the outage. Unit 2 is now available at full capacity and this issue has been resolved.

[15] The planned scope for Unit 1 included the second LSBs as well as stage 11 blades in the intermediate pressure section of the rotor, which were heavily eroded.

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 is a common issue in thermal power plants.[16] To mitigate the possibility of tube failures, Hydro conducts a thorough annual tube inspection and test program; this was executed during the 2025 annual outage season and is scheduled to recur in 2026. Hydro has determined that the boiler tube sections 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.

2.2.2.2 Air Compressors

Compressor 3 failed in the Fall of 2023, and as a result, Hydro has since had two of its three air compressors available for service. A replacement for the failed compressor was ordered; however, due to long lead time, it was not delivered to the site until after the 2024–2025 winter season. The replacement compressor has since been installed, with commissioning scheduled for mid-November 2025, and is expected to be available for the 2025–2026 winter operating season.[17]

Air compressors 1 and 2 continue to experience reliability issues related to operational concerns, including cooling water quality and frequent starts and stops, which particularly occur in the summer when the air demand from the plant is much lower. To mitigate risk if either of these compressors fails, Hydro has secured a 750 CFM[18] portable air compressor to temporarily connect to the system and supply the necessary compressed air to the various systems for which it is required and provide system redundancy. Portable air compressors are an acceptable short-term solution and create minimal risk to operational reliability.

Hydro will continue to monitor this issue.

[16] 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.
[17] As this compressor is expected to be operational prior to December 1, 2025, which will mitigate this risk, it was not included in Hydro's 2025–2026 Winter Readiness Planning Report.
[18] Cubic feet per minute ("CFM").

2.2.3 Ongoing Issues

2.2.3.1 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 General Electric ("GE") 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 GE in February 2023 recommended re-inspection of the crack after nine start-stop cycles. As the 2024 inspection found no crack growth, the unit was cleared for operation for the 2024–2025 winter season.

During the 2025 project to overhaul the Unit 3 steam turbine, the turbine contractor, Mitsubishi Power, completed a repair of this crack. Commissioning of the overhaul work is pending the return to service of the turbine, the date of which was extended to early-February 2026. Hydro has worked with the contractor to explore opportunities to expedite the return to service date, and now expects the unit to be returned to service in mid-January 2026.[19]

Hydro will provide a further update on this issue in its next 2025–2026 Winter Readiness Planning Report.

2.2.3.2 High-Pressure Feedwater Heaters

In recent years, Hydro has experienced increasing difficulty in operating the high-pressure ("HP") feedwater heaters, with most of the heaters unavailable for service during the 2023–2024 operating season due to tube bundle leaks. In 2024, Hydro began a condition assessment program[20] under which all heaters will be opened for internal inspection and tube testing over the next two years.

This program continued in 2025 with a total of six of the nine heaters assessed to date. Four of these heaters were refurbished and returned to service; two had deteriorated severely and could not be refurbished. Replacement of these heaters (Heater 4 on Unit 1 and Heater 6 on Unit 3) is ongoing. Three heaters remain to be assessed in 2026, all of which are available for service. For the 2025–2026 operating season, Unit 1 will have one heater in service, Unit 2 will have three heaters in service, and Unit 3 will have two heaters in service as a result of this ongoing work. Based on heater lead-time and

[19] Note that the expedited return to service date of mid-January 2026 for Unit 3 was determined after the data cutoff date for the analysis within this report; as such, this analysis reflects a return to service date of February 6, 2026, for Unit 3.
[20] "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 21, 2023 (originally filed July 12, 2023), sch. 6, prog. 6.

the need for installation during a unit outage, replacement of the two failed heaters is expected to occur after the 2025–2026 operating season.

Pending replacement of Heater 4 on Unit 1 and Heater 6 on Unit 3, all heaters should be available for service. Condition assessment of HP Heaters 4 and 5 on Unit 2, and Heater 4 on Unit 3, is planned for 2026. These heaters do not have any active tube leaks, but a condition assessment is required to determine if replacement of the heater may be required in the near future, or to identify any severely degraded tubes that should be plugged proactively.

The units can be operated reliably at full load without the HP feedwater heaters in service; however, extended operation through the Bridging Period[21] without the heaters can cause premature failures of turbine and boiler components.

Hydro will provide further information on this issue in the next 2025–2026 Winter Readiness Planning Report.

2.2.4 New Issues

2.2.4.1 Tank Farm Fuel Heating

The heavy fuel oil that is stored in the fuel oil storage tanks in the Holyrood Tank Farm must be heated to flow efficiently to the day tank, which is located adjacent to the powerhouse. Fuel that is drawn from one of the storage tanks passes through heat exchangers called suction heaters, which utilize steam in a tube bundle to heat the fuel oil.[22] Each generating unit has a fuel oil pumping and heating set that takes fuel from the day tank and delivers it to the burners at the correct temperature and pressure for combustion. The fuel in the piping to the day tank and heating sets is further heated by steam trace piping. Duplex strainers on the inlet side of the pumping and heating sets are designed to remove debris from the fuel to ensure reliable operation of the pumps and heaters. The duplex design has two parallel strainers, which allows one strainer to be taken out of service for cleaning without stopping the flow of fuel to the unit. The strainer that is in service must be kept clean to allow full flow of fuel to the burners.

[21] Hydro considers the Bridging Period to be from the present to 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS, Stephenville Gas Turbine ("GT") and the Hardwoods GT until their capacities can be adequately replaced.
[22] There are two suction heaters on each storage tank that operate in parallel.

During the 2024–2025 operating season, fuel heating was limited at times due to issues with the steam heating equipment. The suction heaters on Tank 1 both developed tube leaks after being recently refurbished and tested; the number of plugs required to seal the leaks and prevent oil spills greatly reduced the ability of the heaters to heat the fuel being drawn from the tank. Additionally, numerous steam leaks in the steam piping resulted in poor heating of the fuel. This resulted in insufficient fuel temperature at the day tank for efficient flow through the strainers during longer periods of high load (high fuel flow) operation. Under such conditions, the cleaning of strainers became so frequent that the flow rate had to be reduced to keep up, resulting in a derating. Operations managed the fuel heating by avoiding the use of Tank 1 and by putting two tanks in service at the same time, when possible, such that four suction heaters could be used to heat the fuel rather than just two. This approach was not sufficient in all circumstances, resulting in some periods of derating.

As a continuation of work completed in 2024, extensive work was completed on the steam tracing lines during the 2025 annual outage. All steam trace piping to the three remaining storage tanks and from the day tank to the units has now been replaced. In addition, four replacement suction heaters have been purchased and delivered to the Holyrood TGS in October 2025. Two of the suction heaters will be installed in Tank 1; the other two heaters will be kept as spares and could be installed in Tank 3 or Tank 4, depending on the performance of these heaters through the operating season. Hydro prioritized the consumption of fuel from Tank 1 early in the operating season to reduce the fuel in the tank to minimum storage levels, where the suction heaters can be replaced. This replacement work is planned for completion in mid-to-late November 2025.

Hydro expects that with the replacement of all steam trace piping completed and the pending replacement of suction heaters as required, this issue will be resolved. Hydro will provide a further update on this issue in its next 2025–2026 Winter Readiness Planning Report.

2.2.4.2 Unit 1 Turbine Control Valve

The completion of the Overhaul Unit 1 Turbine Valves and Generator 2024 Program included assessment and refurbishment of the main steam control valves. During the assessment of these components by the turbine service provider, it was discovered that the camshafts that control the opening and closing of the control valves were bent outside of the original equipment manufacturer's (“OEM”) recommended tolerance for reliable operation. Two spare camshafts (OEM supplied) were drawn from stores and used to rebuild the control valve assemblies. During the commissioning of the unit in the Spring of 2025, the load was limited intermittently. The OEM investigated the issue and, after several attempts, determined that pins on the new camshafts were interfering with some of the control valves and preventing full opening. The interference contact was corrected, and the unit subsequently operated correctly.

Unit 1 operated for a brief period before being shut down for the summer. The issue did not return, and Hydro believed that it had been resolved. However, the same intermittent load restriction has been observed since restarting the unit in September 2025, restricting the unit to 100 MW. As such, Hydro believes that there is still some interference between the camshaft pins and the control valves; it is expected that a similar adjustment is required, which will be completed in consultation with the OEM and service provider. Correction of this issue will require a brief unit outage, which is anticipated to occur the week of November 25, 2025, as system conditions permit. Unit 1 will remain online, derated to 100 MW, until that time.

Hydro will provide a further update on this issue in its next 2025–2026 Winter Readiness Planning Report.

2.2.4.3 Fuel Oil Contamination Storage Tank 3

In March 2025, Hydro received a fuel delivery of just over 202,000 barrels. The bulk of this delivery (approximately 180,000 barrels) was allocated to Tank 3, while the remaining (approximately 22,000 barrels) was stored in Tank 1. While this fuel delivery fully complied with Hydro’s specifications, issues with frequent strainer plugging were encountered immediately with fuel drawn from Tank 3, with suspected contamination. At that time, there were also leaks in the steam piping to Tank 3, which limited the amount of heating that could be provided to the fuel oil and may have contributed to the strainer plugging; this has since been corrected.

When Unit 1 was returned to service in September 2025, Tank 4 was in service, and there were no concerns with fuel plugging. Upon switching fuel supply from Tank 4 to Tank 3, strainer plugging became severe, leading to a trip of Unit 1 on September 25, 2025, due to insufficient fuel supply to the boiler.

Operational strategies are being followed to consume the fuel in Tank 3, including using the fuel from Tank 3 in parallel with other tanks to dilute the contaminated fuel and reduce the potential for fouling.

As the tanks must contain the same level of fuel to be utilized in parallel, the fuel in Tank 3 was burned down carefully until it could be placed in parallel with another tank. Tank 3 and Tank 1 have been utilized in parallel since early October 2025, with no major fuel-related issues occurring since that time. A new fuel delivery was received on November 10, 2025, the majority of which was allocated to Tank 3. The risk of operational issues remains, but is diminishing as the fuel from Tank 3 is gradually consumed. It is expected that the contaminated fuel from Tank 3 will be fully consumed by the end of November 2025.

Hydro expects that this issue will be resolved prior to the 2025–2026 winter operating season and will provide further information in its next 2025–2026 Winter Readiness Planning Report.

2.3 Combustion Turbines

There are no issues affecting the reliability of the CTs that have been identified at the time of this filing.

2.4 Muskrat Falls/Labrador Island Link

2.4.1 Resolved Issues

2.4.1.1 Repair Muskrat Falls Unit 2 Turbine

In June 2022, a synchronization issue was identified with Unit 2's Kaplan[23] turbine runner blades. Specifically, the internal mechanical linkage controlling Runner Blade 5 failed, causing it to operate at a different angle than the other blades and resulting in excessive vibration. Additional damage was observed to the turbine crosshead and other internal linkages.

As a temporary measure, it was determined that the unit could be safely and reliably returned to service with the runner blades fixed in place, and Unit 2 was put in service in fixed-blade mode in November 2022.

As recommended by the OEM and reported by The Liberty Consulting Group in its June 2023 Monitoring Report,[24] vibration issues observed on Unit 2 required permanent corrective action, including full unit

[23] Kaplan turbine runners offer superior power regulation by automatically adjusting wicket gate and runner blade positions for optimal efficiency across varying hydraulic heads and power outputs. As a "run of the river" plant, Muskrat Falls frequently experiences daily variations in head and output.

[24] "Nineteeth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System," The Liberty Consulting Group, June 8, 2023.

dismantling to be completed under warranty by the turbine OEM. There were no similar vibration issues or internal inspection findings on Units 1, 3, or 4.

After evaluating long-term options, the decision was made to restore full Kaplan turbine functionality. Unit 2 was fully disassembled during the winter of 2024–2025, with damaged components replaced. The unit was reassembled, recommissioned, and returned to service by the end of August 2025. Muskrat Falls Unit 2 has operated normally with full Kaplan turbine capability since being put back online on September 3, 2025. Hydro considers this issue resolved.

2.4.2 Ongoing Issues

2.4.2.1 Muskrat Falls Unit 1 Intake – Concrete Spalling

During the 2024 planned annual outage to Unit 1, concrete debris was observed in the turbine scroll case. Further inspection indicated some scuffing on the wicket gate lower operating ring caused by the passage of this debris through the turbine, which has since been repaired. This damage did not affect the unit's output or availability.

Remote operated vehicle inspection of the intake civil works identified an area where concrete had cracked and dislodged. In October 2024, a specialized team assessed the condition of the remaining concrete in the area where spalling had been observed. Upon completion of further concrete cutting and removal, sounding of the entire Intake Bay 3 lintel beam was completed with no further areas identified for remedial action. Unit 1 was returned to service on October 16, 2024, with a final repair to the intake civil works planned during the 2025 annual outage.

Due to the unforeseen extension of the planned outage to repair the Muskrat Falls Unit 2 turbine runner, there was insufficient time to complete final repairs on the Unit 1 intake structures in 2025. An inspection to assess the current condition of the intake civil works was carried out during the 2025 annual outage for Unit 1, with a further remote access assessment to be completed in late November 2025. The annual maintenance outage for Unit 1 in 2026 will have time allotted to complete the repairs.

To mitigate risk should a similar incident occur this coming winter, Hydro has a 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 within its first 2026–2027 Winter Readiness Planning Report.[25]

2.4.2.2 Optical Ground Wires Tower Peak and Top Plate Design

Since 2022, several incidents of damage to the optical ground wires ("OPGW") tower peaks have 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.[26]

As a result, a new design to reinforce tower peaks and replace the impacted top plates has been completed. Installation work to rectify the tower peaks and two remaining top plates is expected to begin in 2026, with expected completion in 2028.[27] 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 further information on this issue in the next Rolling 12 Report.

2.4.2.3 Electrode Conductors

In December 2022, March 2024, and January 2025, 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.

Three alternative suspension clamp designs were installed on the electrode conductor at ten structures and will be inspected yearly for performance. An assessment of the electrode suspension assembly and a redesign of the assembly were completed in 2025, with the assemblies to be purchased and installed as required through a future capital project. Additional conductor testing has been completed from these incidents, with further recommendations outlined within the most recent investigation report.[28]

[25] To be filed with the Board on October 13, 2026.
[26] As the OPGW relates to communications functionality, Hydro does not anticipate that further occurrences of similar damage would result in a prolonged power interruption or customer outage.
[27] Analysis confirmed that 63 towers across two tower types (A3 and A4) were identified to have top plates replaced; as of the end of 2024, 61 of 63 were replaced, which represents all A3 towers. The two remaining top plates are on A4 tower types.
[28] For further information, please refer to "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2025," Newfoundland and Labrador Hydro, October 31, 2025, att. 1.

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 further information on this issue in its next Rolling 12 Report.

2.4.2.4 DCCT Cold Weather Operation

In 2023, the OEM and Hydro's Engineering teams identified that low ambient temperatures at the Muskrat Falls High-Voltage Direct Current ("HVDC") Converter Station were affecting the measurement accuracy of direct current current transformers ("DCCT"). This issue led to false protection trips and power control challenges on the LIL.

The root cause was traced to a manufacturing defect in the delay coil fibre optical cable within the DCCTs. This defect was present in a specific batch of fibre-optic cables and impacted six DCCTs at the Muskrat Falls HVDC Converter Station, which have since been replaced.[29]

Hydro will continue to work with the OEM to ensure proper mitigation of the issue. GE has identified a manufacturing facility to replenish spare DCCTs, and Hydro will be actively involved in the design and testing process to ensure that the new units meet operational requirements.

In addition, GE is preparing a revised plan to address DCCTs which have low risk indicators of the issues related to cold weather operation. GE has indicated that the plan will be provided in the fourth quarter of 2025. Hydro is actively engaged in discussions to ensure that any adopted strategy maintains system reliability and operational integrity.

Hydro will provide further information on this issue in its next Rolling 12 Report.

2.4.2.5 Cable Switching

As reported in Hydro's final 2024–2025 Winter Readiness Report,[30] new equipment was successfully installed to mitigate cable switching transients at the LIL Transition Compounds in mid-October 2024. Since that time, Hydro has identified an icing issue with transition compound disconnects that can impact cable switching in winter conditions. A solution to resolve this issue will be finalized in November

[29] One of these DCCTs has an operation rating to -40°C, and will be replaced with a DCCT rated to -50°C in 2025.
[30] Reliability and Resource Adequacy Study Review – 2024–2025 Winter Readiness Planning Report – Final Report," Newfoundland and Labrador Hydro, December 10, 2024.

in consultation with GE, with plans for installation prior to the end of December 2025. In the interim, Hydro is developing operating procedures to support reliable operation in winter conditions.

Hydro will provide further information on this issue in its next Rolling 12 Report.

2.4.2.6 Synchronous Condenser Brush Gear Assemblies

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

Hydro, in consultation with the OEMs for the brush equipment and the synchronous condensers, has been working to identify the root cause of the brush performance issues. Hydro has continued with the modified brush configurations and operational controls to ensure optimal operating conditions for patina development. These changes have had positive results with regard to brush performance in 2025.

In spring 2024, the existing slip ring was removed from Synchronous Condenser 1 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 will continue to monitor the overall impact of these changes.

GE has been working with a different brush gear manufacturer; however, given the positive brush gear performance in 2025, both GE and Hydro recommended not changing the design at this time. As the performance of a new brush and holder is unknown until they are installed and tested, the recommendation is to continue to operate under the existing design. GE has provided Hydro with operational limits based on the number of brushes installed per ring to help maintain patina film.[31] Corrective actions on all three units have yielded positive results, and changes performed in 2024 have aided in achieving acceptable brush performance across all three synchronous condensers.

Hydro will provide further information on this issue in its next Rolling 12 Report.

[31] The current limit is -50 MW to +90 MW.

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 publicly 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 2024 Near-Term Report are included for comparison.

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

Table 1: Near-Term FORs for Hydro-Operated Assets

Asset	2024 Reliability Metric	2025 Reliability Metric
Hydraulic Units[34]	DAFOR = 3.6%	DAFOR = 2.5%
Muskrat Falls	DAFOR = 2.3%	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	DAUFOP = 30%	DAUFOP = 30%
Diesels	DAUFOP = 6.1%	DAUFOP = 6.4%

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 2024 Electricity Canada ("EC") Generating Equipment Reliability Information System.[35,36] FORs used for assets owned by a third party in this analysis are presented in Table 2. Assumptions used in the November 2024 Near-Term Report are included for comparison.

Table 2: FORs for Third-Party Operated Assets

Asset	2024 Reliability Metric	2025 Reliability Metric
Hydraulic Units	DAFOR = 7.1%	DAFOR = 4.9%
GTs	DAUFOP = 5.2%	DAUFOP = 5.4%
CBPP[37] Capacity Assistance (CoGen/Hydro)	DAUFOP = 19.2%	DAUFOP = 19.2%

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 in service throughout the study period.[38] Hydro has assumed a DAUFOP of 30%,

[34] Excluding Muskrat Falls.
[35] The 2024 EC Generating Equipment Reliability Information System provides five-year average statistics based on the years 2020–2024.
[36] EC reliability data is published annually. EC reliability data is not currently available for 2025.
[37] Corner Brook Pulp and Paper Limited ("CBPP").
[38] While Newfoundland Power was previously looking to retire these units, they have expressed that there may be justification to refurbish and uprate these units 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.

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 within assumed reliability metrics since it was commissioned on April 14, 2023. The 12-month annual average EqFOR for the period October 1, 2024 to September 30, 2025, was 0.76%.[39,40]

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 in this 2025 Near-Term Reliability Report remain consistent with the 2024 Plan, except for the addition of a scenario with a LIL EqFOR of 3% and the removal of the Scenario with a 10% LIL EqFOR. The LIL has performed within this range since commissioning. However, multiple years of operational experience are required to better inform the longer-term selection of a bipole EqFOR. In the interim, the bipole EqFOR will be addressed with a range of upper and lower limits. As LIL performance statistics become available in the coming years, the EqFOR range may be further narrowed in future filings.

Hydro anticipates a controlled 900 MW test will be performed in late winter 2025–2026, 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.

[39] This EqFOR statistic was calculated based on the present rating of the LIL (700 MW).
[40] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2025," Newfoundland and Labrador Hydro, October 31, 2025.

As described in the 2024 Resource Adequacy Plan, Hydro plans to keep the Holyrood TGS available through the Bridging Period until April 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

Therefore, the three units at the Holyrood TGS are considered operational from 2026 until April 2030.

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. Therefore, both the Hardwoods GT and Stephenville GT are assumed to be available through the near-term study period (2026–2030).

3.3 2025 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[41] and industrial load.[42] 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.

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

3.3.2 Economic Setting

The Newfoundland and Labrador economy grew (6.6%) in 2024 as economic indicators showed moderate to strong growth. Total employment increased 2.8% in 2024, and the unemployment rate remained at 10%. The provincial population also continues to experience growth, with an increase of 0.4% from April 2024 to April 2025. Capital investment continued to rebound from 2020 and 2021 levels, and housing starts were up 71% due to increased building incentives and market shortages. Other economic indicators, such as household disposable income, improved throughout the year.

Total oil production increased by 4.6% compared to 2023; the value of oil production increased by 4.2% due to higher production offset by lower prices. Mineral shipments were down 0.6% from 2023, primarily due to lower iron ore and nickel prices. The seafood sector had an increase in fish landings by 11.3% compared to 2023, and the value of landed catch increased by 33.6%. Aquaculture production saw an increase of 31.3% compared to 2023 and an increase of 21.9% in market value.

Looking forward through the medium term (i.e., one to five years), there are several developments that will positively influence provincial economic activity. The White Rose Oil Project is expected to continue to ramp up production with the completion of the project.

The mining sector continues to have encouraging developments. Equinox Gold Corporation continues to advance its Valentine Gold Project in central Newfoundland, with the first production in the third quarter of 2025. Firefly Metals Limited continue to advance its Green Bay Copper-Gold Project. 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 Gross Domestic Product ("GDP") is forecast to increase, primarily due to increased oil and mineral production. Most other economic indicators are also forecast to show growth. According to current provincial economic reports by many Canadian financial institutions, total oil production is expected to increase as the White Rose oil field continues to increase production from the Sea Rose FPSO[43] vessel with the completion of the West White Rose Project. Mining activity is also expected to increase and remains a bright spot for medium-term growth. Newfoundland and Labrador is

[43] Floating Production, Storage, and Offloading ("FPSO").

set to weather trade issues as only one-third of its exports go to the United States, with the remaining two-thirds going to Europe.[44,45]

The current provincial outlook for 2025 continues to be positive. This is primarily driven by natural resource production—this sector accounts for one-third of the provincial GDP. The employment landscape is positive, and unemployment rates remain low. The tourism sector also offers growth potential as travel to the United States diminishes.

3.3.3 Island Interconnected System Load Forecast

3.3.3.1 Reference Case

The Island Interconnected System Reference Case[46] peak demand forecast is provided in Table 3.

Table 3: Island Interconnected System Reference Case Demand Forecast (MW)[47]

	2026	2027	2028	2029	2030
Utility[48]	1,590	1,599	1,613	1,636	1,652
Industrial Customer	154	160	160	160	162
Customer Coincident Demand	**1,744**	**1,759**	**1,773**	**1,796**	**1,814**
Transmission Losses and Station Service[49]	44	44	45	45	46
Total Demand	**1,788**	**1,803**	**1,818**	**1,841**	**1,860**

Table 4 compares the current load forecast with the 2024 load forecast, which was used in both the 2024 Near-Term Reliability Report and the 2025 Build Application.

Table 4: Comparison of Reference Case Peak Demand Forecasts (MW)[50]

	2026	2027	2028	2029	2030
2024 Customer Coincident Demand	1,742	1,757	1,778	1,807	1,819
2025 Customer Coincident Demand	1,744	1,759	1,773	1,796	1,814
Difference (MW)	**+2**	**+2**	**-5**	**-11**	**-5**
Difference (%)	**+0.1**	**+0.1**	**-0.3**	**-0.6**	**-0.3**

[44] "Provincial Economic Forecast: Prairie and Atlantic Economies Holding Up Better Amid Tariff Whipsaw," TD Economics, June 18, 2025, https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Jun2025.pdf.
[45] "Macroeconomic Outlook–Canada's economic outlook: Shifting tides as tariff threats de-escalate," RBC Economics, June 13, 2025, https://www.rbc.com/en/economics/canadian-analysis/featured-analysis/quarterly-canadian-outlook/canadas-economic-outlook-shifting-tides-as-tariff-threats-de-escalate/.
[46] Hydro's expected load forecast of firm electric power demand and energy requirements for the Island Interconnected System, based upon the current investments in decarbonization, driven primarily through government policy and programs, anticipated electrification of the transportation sector, stable population, and strong demand for new housing.
[47] Numbers may not add due to rounding.
[48] The utility demand forecast includes approximately 22 MW of potential interruptible load starting in the winter of 2026.
[49] Excluding LIL losses.
[50] Before losses and station service loads.

The 2025 Reference Case load forecast reflects minor changes in peak demand requirements through the study period as compared to the 2024 forecast.

3.3.3.2 Slow Electrification Case

The Island Interconnected System Slow Electrification Case[51] peak demand forecast is provided in Table 5.

Table 5: Island Interconnected System Slow Electrification Case Peak Demand Forecast (MW)[52]

	2026	2027	2028	2029	2030
Utility[53]	1,588	1,594	1,605	1,624	1,637
Industrial Customer	150	155	155	155	158
Customer Coincident Demand	**1,738**	**1,749**	**1,760**	**1,779**	**1,795**
Transmission Losses and Station Service	44	44	44	45	45
Total Demand	**1,782**	**1,793**	**1,804**	**1,824**	**1,840**

Table 6 compares the current Slow Electrification load forecast with the 2024 Slow Decarbonization load forecast, which was used in the 2025 Build Application.

Table 6: Comparison of Slow Electrification Case Peak Demand Forecasts (MW)[54]

	2026	2027	2028	2029	2030
2024 Customer Coincident Demand	1,739	1,747	1,758	1,782	1,791
2025 Customer Coincident Demand	1,738	1,749	1,760	1,779	1,795
Difference (MW)	**-1**	**+2**	**+2**	**-3**	**+4**
Difference (%)	**-0.1**	**+0.1**	**+0.1**	**-0.2**	**+0.2**

The 2025 Slow Electrification load forecast reflects minor changes in peak demand requirements through the study period as compared to the 2024 forecast.

[51] Hydro's Island Interconnected System Slow Electrification 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.
[52] Numbers may not add due to rounding.
[53] The utility demand forecast includes approximately 22 MW of potential interruptible load in Winter 2026.
[54] Before losses and station service loads.

Table 7 compares the 2025 Reference Case load forecast with the 2025 Slow Electrification load forecast.

Table 7: Comparison of Reference Case and Slow Electrification Case Peak Demand Forecasts (MW)[55]

	2026	2027	2028	2029	2030
2025 Reference Case Peak Demand	1,744	1,759	1,773	1,796	1,814
2025 Slow Electrification Peak Demand	1,738	1,749	1,760	1,779	1,795
Difference (MW)	**+6**	**+10**	**+13**	**+17**	**+19**
Difference (%)	**+0.3**	**+0.6**	**+0.7**	**+0.9**	**+1.0**

The 2025 Reference Case peak demand forecast shows slightly higher requirements compared to the 2025 Slow Electrification Case throughout the study period.

3.4 System Energy Capability

In order to reliably serve customers, Hydro maintains minimum limits for aggregate energy storage in its major hydroelectric reservoirs on the Island Interconnected System. These limits are developed annually to ensure that Hydro is capable of meeting customer demands throughout the year in the event of a repeat of Hydro's critical dry sequence.[56] The limits are established such that Hydro will have sufficient hydraulic storage to be able to meet the load in this critical sequence, or another less severe sequence, through the use of Island hydraulic production supplemented with maximized deliveries of energy to the Island from Labrador over the LIL. This includes energy from Muskrat Falls as well as recaptured energy available to Hydro from the Churchill Falls Hydroelectric Generating Station.

The established limits assume that two Holyrood TGS units will be online, operating at minimum output (70 MW) during winter 2025–2026, and do not include the use of standby thermal generation to support reservoir storage, or the third unit at Holyrood TGS. The minimum storage methodology ensures Hydro's reservoirs can continue to provide reliable, least-cost service to customers in an environmentally responsible manner by supporting Island load with hydroelectric energy instead of thermal energy to the extent possible.[57]

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[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). Other dry periods are also considered during this analysis to ensure that no other shorter-term historic dry sequence could result in insufficient storage.
[57] The limits also do not consider the availability of imports over the Maritime Link, though imports can provide an additional opportunity to supplement storage and economically reduce the amount of thermal generation required to maintain sufficient energy in storage in the event that import opportunities arise.

Since May 2025, Hydro's Island reservoirs have experienced persistent below-average inflows as reported in Hydro's Monthly Energy Supply reports. The entirety of the island portion of the province has experienced some level of drought conditions throughout the summer and early fall. The portions of the province where Hydro's reservoirs are located have experienced severe to extreme drought as of the end of October 2025, based on the Canadian Drought Monitor published by Agriculture and Agri-Food Canada. Overall inflows to the reservoirs of the Island Interconnected System were 68% below the historical average from May 2025 to October 2025.

Starting in mid-May, Island system storage steadily declined due to ongoing low inflows. On October 31, 2025, aggregate reservoir storage was 1,007 GWh, which was 41% of the maximum operating level and 94% of (approximately 62 GWh below) the minimum storage limit. However, as a result of elevated inflows from successive rain events across the Island reservoirs in November, system storage has improved over the last few weeks. As of November 19, 2025, aggregate reservoir storage was 1,426 GWh, which is 58% of the maximum operating level and 126% of (approximately 296 GWh above) the minimum storage limit. November inflow to date has been 194% of the historical average for the month.

Figure 1 plots the 2024 and 2025 storage levels, minimum storage limits, maximum operating level storage, and the 20-year average aggregate storage for comparison. Please note that the minimum storage limits for 2025–2026 have been updated as of September 30, 2025, utilizing the LIL transmission limits associated with the "full" or final under-frequency load shedding ("UFLS") scheme as opposed to the previously presented and "interim" UFLS scheme, as work is ongoing to implement the final UFLS scheme in November.[58] The final UFLS scheme allows for incrementally more LIL energy to be brought to the Island without conversely needing to export more energy over the Maritime Link export path. This resulted in a small adjustment downwards of the monthly minimum storage limits.

[58] This work is being completed in conjunction with Newfoundland Power.

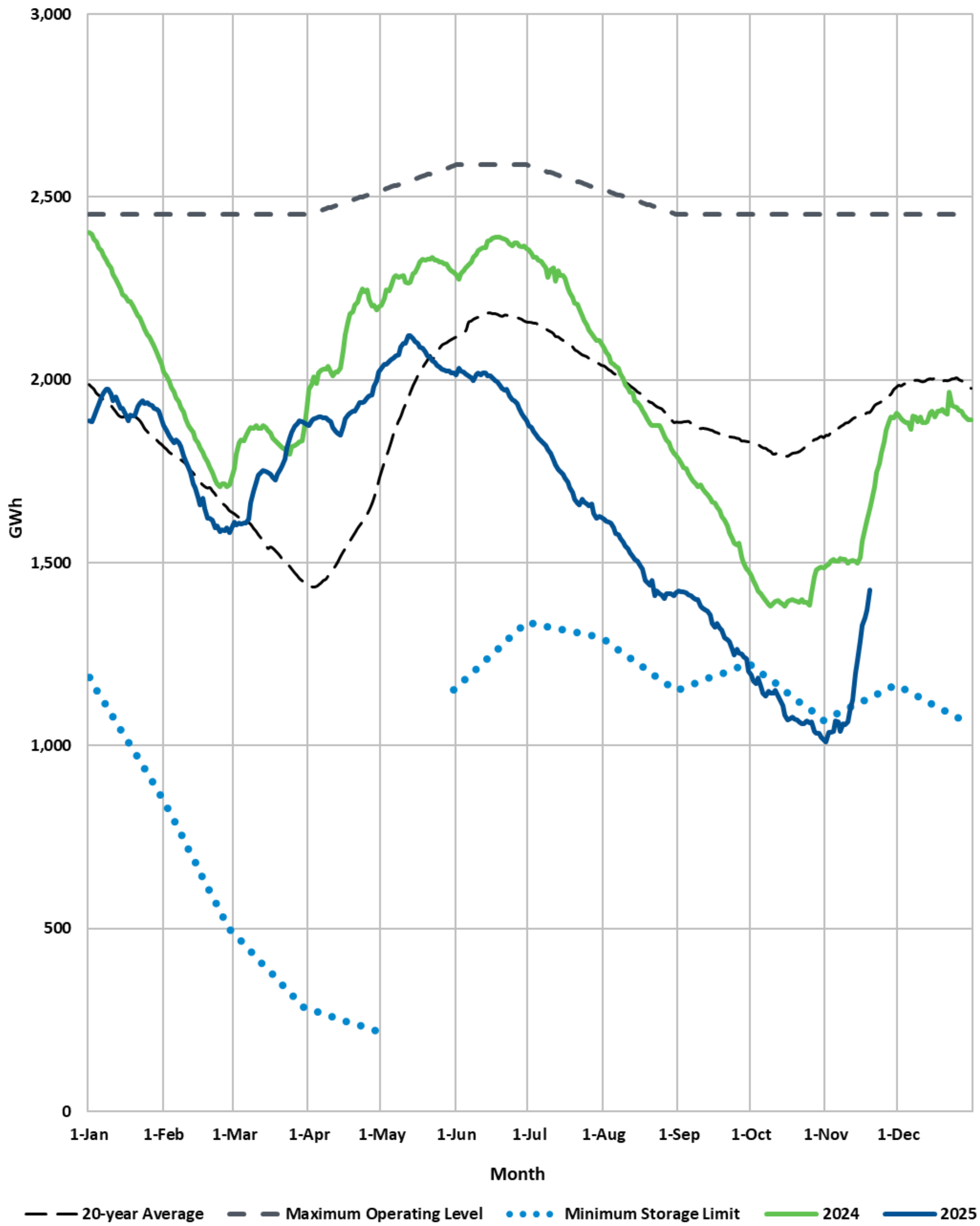

Figure 1: Total System Energy Storage[59]

[59] Data points in Figure 1 represent storage at the beginning of each day. The body of the report text reports the end-of-day storage value, which results in a small difference between the storage data presented in the text and Figure 1.

Deliveries of energy to the Island Interconnected System from Labrador via the LIL were maximized to the extent possible to support Island reservoir storage during periods of low inflow. During planned monopole outages, Hydro has implemented "Economic Monopole Operation" when system conditions permit, which allows for additional energy delivery to the Island during monopole operation. While this mode of operation inherently introduces a risk of UFLS in the event of a trip, scheduling and operation while in that mode is carried out to limit the customer impact to UFLS blocks down to and including the 58.4 Hz block.

Hydro also engaged Energy Marketing to seek imports over the Maritime Link to supplement reservoir storage during planned LIL outages or derates. Exports from Island sources have been placed on hold since July 2025.

When available, Holyrood TGS Units 1 and 2 were online and operating above minimum, as system conditions allowed to support reservoir storage during September and October 2025. With elevated inflows and improved system storage in November 2025, the Holyrood TGS is no longer being operated above minimum to support reservoir storage.

Hydro will continue to closely monitor Island storage and inflows at both the overall system and the individual reservoir levels to ensure its hydroelectric assets can operate through the winter season at full rated output. At this time, the use of standby generation is not deemed to be required to support reservoir 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 ("NS 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 its contractual obligations to Prince Edward Island.

    - The interface between the New Brunswick/Nova Scotia transmission system is often congested. However, in December 2023, NS Power received environmental approval[60] from the Nova Scotia government for the construction of a new 345 kV 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.[61] 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 its native load.

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[60] "NS-NB Reliability Intertie Project," Government of Nova Scotia, https://www.novascotia.ca/nse/ea/ns-nb-reliability-intertie/.
[61] "NS-NB Reliability Tie," Nova Scotia Power, https://www.nspower.ca/cleanandgreen/clean-energy/ns-nb-reliability-tie.

It is important to note that there are also Island transmission constraints in delivering imported energy via the Maritime Link to the Avalon Peninsula.[62]

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,[63] NS Power continues to plan to retire coal by 2030 and does not have surplus capacity in its system to export. Nova Scotia is investing significantly to add additional capacity to meet load increases and to replace existing assets. 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 and provincial government regulations.
- **New Brunswick**: NB Power filed a ten-year Integrated Resource Plan in 2023,[64] at which time, it outlined the requirement to build additional capacity to meet load growth and decarbonization plans. In July 2025, NB Power announced they are working with a private developer to construct a 400 MW to 500 MW natural gas plant to meet earlier than forecasted 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 2025, 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.

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[62] Please refer to "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, sec. 5.4.1.1, pp. 51–53.
[63] "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.
[64] "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 7.5 MW of capacity assistance with Vale is renewed for each winter season in the study period. Hydro is in discussions with Vale regarding the terms and conditions of a capacity assistance agreement for the 2025–2026 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 outside of the winter 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 2025 load forecast includes Memorial University of Newfoundland's ("MUN") electric boiler (approximately 22 MW of load) entering service in the fourth quarter of 2025. MUN plans to retain its oil boiler as backup and, when required, will be able to run the oil-fired boilers instead of the new electric boilers. Newfoundland Power and MUN are currently in discussion on an agreement which would allow for the electric boiler load to be curtailed during system needs. The commissioning of the MUN electric boiler project is now anticipated in the first quarter of 2026. Following commissioning, MUN plans to perform trials with its electric boiler system to determine response times for curtailment purposes. Hydro is working with Newfoundland Power to determine the amount of load MUN expect to have on the system this winter and how they plan to operate their system once the new electric boilers have been commissioned.

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 EqFOR. This case assumes a DAUFOP of 20% for the Holyrood TGS and the 2025 Reference Case load forecast.
- **Scenario 2:** Varies from Scenario 1 by considering the 2025 Slow Electrification load forecast rather than the 2025 Reference Case load forecast.
- **Scenario 3:** Varies from Scenario 1 by maintaining a 3% bipole EqFOR through the study period.
- **Scenario 4**: Varies from Scenario 1 by maintaining a 1% bipole EqFOR through the study period.
- **Scenario 5**: Varies from Scenario 1 by considering the 2025 Slow Electrification load forecast and maintaining 1% bipole EqFOR.

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

- **Scenario 1A:** The forced outage rate of Holyrood TGS is increased to 34% from 20%.
- **Scenario 1B:** Assumes the LIL bipole capacity is increased to 900 MW.
- **Scenario 1C:** Holyrood Unit 3 remains out of service through the winter of 2025–2026.

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 Scenario 1 sensitivities.

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 8. 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.[65]

Table 8: Scenarios 1 to 5 Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2026	2027	2028	2029	2030
Scenario 1: Reference Case	1.8	1.1	1.0	1.3	1.5
Scenario 2: Slow Electrification load	1.8	1.0	0.9	1.0	1.2
Scenario 3: LIL Bipole EqFOR = 3%	1.1	0.7	0.6	0.7	0.9
Scenario 4: LIL Bipole EqFOR = 1%	0.8	0.3	0.2	0.3	0.3
Scenario 5: Slow Electrification load and LIL Bipole EqFOR = 1%	0.8	0.3	0.2	0.3	0.3

EUE (MWh)	2026	2027	2028	2029	2030
Scenario 1: Reference Case	130	70	60	90	100
Scenario 2: Slow Electrification load	130	60	60	70	80
Scenario 3: LIL Bipole EqFOR = 3%	80	40	40	50	70
Scenario 4: LIL Bipole EqFOR = 1%	70	20	20	20	20
Scenario 5: Slow Electrification load and LIL Bipole EqFOR = 1%	60	20	10	20	20

NEUE (ppm)[66]	2026	2027	2028	2029	2030
Scenario 1: Reference Case	15	8	7	10	11
Scenario 2: Slow Electrification load	15	7	7	8	9
Scenario 3: LIL Bipole EqFOR = 3%	9	5	5	6	8
Scenario 4: LIL Bipole EqFOR = 1%	8	2	2	2	2
Scenario 5: Slow Electrification load and LIL Bipole EqFOR = 1%	7	2	1	2	2

In Scenario 1 (Reference Case), the LOLH remains below Hydro's planning criteria of 2.8 for all years. Scenario 2, which assumes a Slow Electrification load outlook, also remains within the planning criteria across the study period. In Scenario 3, with the LIL Bipole EqFOR decreased to 3%, the planning criteria is not exceeded in any of the five years assessed. Scenario 4 assumes a lower LIL Bipole EqFOR of 1% and maintains LOLH below the criteria in all years. Scenario 5, which combines Slow Electrification load growth with a 1% LIL Bipole EqFOR, similarly shows LOLH remaining below Hydro's planning criteria for all years.

[65] LOLH is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity.
[66] 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.

4.1.2 Monthly Results

Table 9 to Table 13 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.

Table 9: Scenarios 1 to 5 Monthly LOLH and EUE for 2026[67]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Slow Electrification load	1.2	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 3: LIL Bipole EqFOR = 3%	0.7	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 4: LIL Bipole EqFOR = 1%	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	100	20	10	0	0	0	0	0	0	0	0	10
Scenario 2: Slow Electrification load	90	20	10	0	0	0	0	0	0	0	0	0
Scenario 3: LIL Bipole EqFOR = 3%	60	20	0	0	0	0	0	0	0	0	0	0
Scenario 4: LIL Bipole FOR = 1%	50	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	40	20	0	0	0	0	0	0	0	0	0	0

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

Table 10: Scenarios 1 to 5 Monthly LOLH and EUE for 2027[68]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Slow Electrification load	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 3: LIL Bipole EqFOR = 3%	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 4: LIL Bipole EqFOR = 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 Elect load + LIL Bipole EqFOR 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

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	30	20	10	0	0	0	0	0	0	0	0	10
Scenario 2: Slow Electrification load	30	20	10	0	0	0	0	0	0	0	0	10
Scenario 3: LIL Bipole EqFOR = 3%	20	20	0	0	0	0	0	0	0	0	0	0
Scenario 4: LIL Bipole EqFOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	10	10	0	0	0	0	0	0	0	0	0	0

Table 11: Scenarios 1 to 5 Monthly LOLH and EUE for 2028[69]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: Slow Electrification load	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 3: LIL Bipole EqFOR = 3%	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 4: LIL Bipole EqFOR = 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 Elect load + LIL Bipole EqFOR 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

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	20	20	10	0	0	0	0	0	0	0	0	10
Scenario 2: Slow Electrification load	20	20	10	0	0	0	0	0	0	0	0	10
Scenario 3: LIL Bipole EqFOR = 3%	20	10	0	0	0	0	0	0	0	0	0	10
Scenario 4: LIL Bipole EqFOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	0	0	0	0	0	0	0	0	0	0	0	0

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

Table 12: Scenarios 1 to 5 Monthly LOLH and EUE for 2029[70]

LOLH (hours)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Scenario 1: Reference Case	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 2: Slow Electrification 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
Scenario 3: LIL Bipole EqFOR = 3%	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 4: LIL Bipole EqFOR = 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 Elect load + LIL Bipole EqFOR 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

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: Slow Electrification load	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 3: LIL Bipole EqFOR = 3%	20	20	10	0	0	0	0	0	0	0	0	10
Scenario 4: LIL Bipole EqFOR = 1%	10	10	0	0	0	0	0	0	0	0	0	0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	10	10	0	0	0	0	0	0	0	0	0	0

Table 13: Scenarios 1 to 5 Monthly LOLH and EUE for 2030[71]

LOLH (hours)	**Jan**	**Feb**	**Mar**	**Apr**
Scenario 1: Reference Case	0.7	0.6	0.2	0.0
Scenario 2: Slow Electrification load	0.6	0.5	0.2	0.0
Scenario 3: LIL Bipole EqFOR = 3%	0.4	0.4	0.1	0.0
Scenario 4: LIL Bipole EqFOR = 1%	0.1	0.1	0.0	0.0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	0.1	0.1	0.0	0.0

EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**
Scenario 1: Reference Case	50	40	10	0
Scenario 2: Slow Electrification load	40	30	10	0
Scenario 3: LIL Bipole EqFOR = 3%	30	30	10	0
Scenario 4: LIL Bipole EqFOR = 1%	10	10	0	0
Scenario 5: Slow Elect load + LIL Bipole EqFOR 1%	10	10	0	0

The monthly results show the expected result that most of the LOLHs and expected unserved energy occur in the month of January, when the load is at its highest, and Holyrood TGS Unit 3 is delayed returning to service. Some loss of load events also occur in December, February, and March, with very few loss of load events in other months.

[70] Monthly results may not add up to annual results due to rounding.
[71] 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 14. 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 14: Scenario 1 Sensitivities Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2026	2027	2028	2029	2030
Scenario 1: Reference Case	1.8	1.1	1.0	1.3	1.5
Scenario 1A: Holyrood TGS DAUFOP = 34%	**4.1**	**3.0**	2.7	**3.4**	**3.6**
Scenario 1B: LIL at 900 MW	1.9	1.1	0.9	1.2	1.5
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	2.7	N/A	N/A	N/A	N/A

EUE (MWh)	2026	2027	2028	2029	2030
Scenario 1: Reference Case	130	70	60	90	100
Scenario 1A: Holyrood TGS DAUFOP = 34%	320	220	200	270	310
Scenario 1B: LIL at 900 MW	140	70	70	80	110
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	200	N/A	N/A	N/A	N/A

NEUE (ppm)	2026	2027	2028	2029	2030
Scenario 1: Reference Case	15	8	7	10	11
Scenario 1A: Holyrood TGS DAUFOP = 34%	38	26	24	31	36
Scenario 1B: LIL at 900 MW	17	8	8	9	13
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	24	N/A	N/A	N/A	N/A

Scenario 1A results above indicate that increasing the DAUFOP for Holyrood TGS units from 20% to 34% significantly reduces system reliability. The risk of having a loss of load event more than doubles in 2026 compared to the reference case, with LOLH rising from 1.8 to 4.1. Elevated LOLH values persist through the study period. These results highlight the importance of Holyrood TGS Units' reliability during peak demand periods.

Scenario 1B shows that increasing the LIL bipole capacity to 900 MW has an insignificant effect on overall system reliability. Loss of load risk remains largely consistent with the reference case throughout the analysis period, with only minor fluctuations. This indicates that reliability challenges are primarily driven by LIL unavailability rather than capacity constraints.

Scenario 1C results above indicate that if Holyrood TGS Unit 3 were to remain out of service for the winter of 2025–2026, the risk of having a loss of load event increases for the year 2026. The results in other years are unchanged from Scenario 1 since there was no change in inputs for those years.

4.2.2 Monthly Results

Table 15 to Table 19 provide LOLH and EUE for each year by month for Scenario 1 sensitivities.

Table 15: Scenario 1 Sensitivities Monthly LOLH and EUE for 2026[72]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: Holyrood TGS DAUFOP = 34%	2.3	1.0	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 1B: LIL at 900 MW	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	1.2	1.0	0.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	100	20	10	0	0	0	0	0	0	0	0	10
Scenario 1A: Holyrood TGS DAUFOP = 34%	200	80	20	10	0	0	0	0	0	0	0	20
Scenario 1B: LIL at 900 MW	100	30	10	0	0	0	0	0	0	0	0	10
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	90	80	20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 16: Scenario 1 Sensitivities Monthly LOLH and EUE for 2027[73]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: Holyrood TGS DAUFOP = 34%	1.1	0.9	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3
Scenario 1B: LIL at 900 MW	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	30	20	10	0	0	0	0	0	0	0	0	10
Scenario 1A: Holyrood TGS DAUFOP = 34%	90	70	20	10	0	0	0	0	0	0	10	20
Scenario 1B: LIL at 900 MW	30	20	10	0	0	0	0	0	0	0	0	10
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

Table 17: Scenario 1 Sensitivities Monthly LOLH and EUE for 2028[74]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: Holyrood TGS DAUFOP = 34%	1.0	0.8	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.4
Scenario 1B: LIL at 900 MW	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	20	20	10	0	0	0	0	0	0	0	0	10
Scenario 1A Holyrood TGS DAUFOP = 34%	80	60	20	0	0	0	0	0	0	0	0	30
Scenario 1B: LIL at 900 MW	30	20	10	0	0	0	0	0	0	0	0	10
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 18: Scenario 1 Sensitivities Monthly LOLH and EUE for 2029[75]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: Reference Case	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1A: Holyrood TGS DAUFOP = 34%	1.2	1.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 1B: LIL at 900 MW	0.4	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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: Holyrood TGS DAUFOP = 34%	100	100	30	0	0	0	0	0	0	0	0	30
Scenario 1B: LIL at 900 MW	30	30	10	0	0	0	0	0	0	0	0	10
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

Table 19: Scenario 1 Sensitivities Monthly LOLH and EUE for 2030[76]

LOLH (hours)	Jan	Feb	Mar	Apr
Scenario 1: Reference Case	0.7	0.6	0.2	0.0
Scenario 1A: Holyrood TGS DAUFOP = 34%	1.6	1.5	0.5	0.0
Scenario 1B: LIL at 900 MW	0.7	0.6	0.2	0.0
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr
Scenario 1: Reference Case	50	40	10	0
Scenario 1A: Holyrood TGS DAUFOP = 34%	140	130	40	0
Scenario 1B: LIL at 900 MW	50	50	10	0
Scenario 1C: Holyrood TGS Unit 3 out of service for Winter 2025–2026	N/A	N/A	N/A	N/A

The monthly results indicate that the highest reliability risk occurs in January, which aligns with peak winter load conditions. Elevated but lesser reliability risks are also observed in February, March, and December. Across all Scenario 1 sensitivities and years, no loss of load events were experienced during the summer months (June through September), indicating strong reliability during that period.

5.0 Conclusion

Hydro continues to closely monitor its supply-related assets to ensure reliable service to customers. In the Reference Case (Scenario 1), which is what Hydro expects to occur in the near term, system reliability remains within Hydro's planning criterion of 2.8 LOLH per year. 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 nearly all years if the Holyrood TGS experiences a higher-than-expected FOR of 34% (Scenario 1A). In Scenario 1C, if the Holyrood TGS Unit 3 outage extends through the full winter of 2025–2026, the results show that the planning criteria is approaching the LOLH threshold in 2026. It is important to note that exceeding the

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

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] Scenarios 3 through 5 examine the impact of LIL performance on system reliability. A decrease in LIL EqFOR results in a large improvement in LOLH and EUE in all years of the study period. However, as demonstrated in Scenario 1B, which included the LIL at 900 MW, there are very little reliability gains between 700 MW and 900 MW capacity. Heading into the 2025–2026 winter operating season, the LIL will be available at a rating of 700 MW.

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 3 at the Holyrood TGS until mid-January 2026 will put additional strain on the system; however, Hydro is actively working towards returning this unit to service as soon as possible.

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 reliably 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, pending Board approval. 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 the risk of outages.

[77] Until there have been multiple years of operational experience for the LIL to better inform the selection of a bipole EqFOR, the LIL bipole EqFOR 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 further in future filings.

Hydro remains focused on the completion of its annual maintenance program to ensure the reliability of its existing assets in advance of the 2025–2026 winter operating season, as well as monitoring the health of the assets to ensure continued, reliable, least-cost supply for customers.