newfoundland labrador hydro

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

November 15, 2023

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 & Board Secretary

Re: *Reliability and Resource Adequacy Study Review* – 2023 Near-Term Reliability Report – November Report

Further to the Board of Commissioners of Public Utilities' ("Board") 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 2023 Near-Term Reliability Report – November Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Cheryl Blundon
Maureen Greene, KC
PUB Official Email

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

Newfoundland Power Inc.
Dominic J. Foley
Lindsay S.A. Hollett
Regulatory Email

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Consumer Advocate
Dennis M. Browne, KC, Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

[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

2023 Near-Term Reliability Report – November Report

November 15, 2023

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

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

This report discusses near-term modelled resource adequacy and reliability and provides the results of the probabilistic resource adequacy assessment of the Newfoundland and Labrador Interconnected System for the 2024–2028 study period. 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."[1]

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").[2] The analysis considers the different types of generating units (i.e., thermal, hydro, and wind) in Hydro's fleet, firm capacity contractual sales and purchases, transmission constraints, peak load, load variations, load forecast uncertainty, and demand-side management programs. Similar to previous analyses, a range of projected availabilities were considered for the Holyrood Thermal Generating Station ("Holyrood TGS") and the Labrador-Island Link ("LIL").[3] In addition, Hydro was asked by the Board of Commissioners of Public Utilities ("Board") to assess the implications of a further generator step-up ("GSU") transformer failure within this report, specifically addressing the implications of a GSU transformer failure at the Holyrood TGS during the upcoming 2023–2024 winter operating season.[4] This issue, in addition to other requests for consideration from Newfoundland Power Inc. ("Newfoundland Power") and the Public Utilities Board, are addressed in Section 3.5 of this report.

[1] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016, p. v. <https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf>.
[2] 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").
[3] A range of potential LIL bipole forced outage rates were considered, consistent with the analysis conducted in the "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022 ("2022 Update") and the "Reliability and Resource Adequacy Study - 2023 Update - Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, June 2, 2023 ("May 2023 Near-Term Report").
[4] "NLH – 2023 Capital Budget Supplemental Application – Approval of the Purchase of a Spare Generator Step-Up Transformer – Newfoundland Power's Comments," Newfoundland Power Inc., September 29, 2023. <http://pub.nl.ca/applications/NLH2023Capital_SUPP_SpareGenerator/correspondence/From%20NP%20-%20Comments%20-%202023-09-29.PDF>.

Given the evolving nature of the Newfoundland and Labrador Interconnected System, an analysis was conducted for the period from 2024 to 2028 to provide the Board with insight into the evolution of system reliability as the Muskrat Falls Project Assets are reliably integrated. Since the filing of the May 2023 Near-Term Report, the LIL was commissioned[5] and has continued to operate reliably. Hydro anticipates a controlled 900 MW test will be performed on the LIL in 2024 at the end of the first quarter or the beginning of the second quarter, as system conditions permit.

2.0 Modelling Approach

The analysis in this report has been completed using Hydro's reliability model. This model has been used to assess system reliability since the "Reliability and Resource Adequacy Study" ("2018 Filing"),[6] with updates to reflect current system assumptions.[7]

Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these assessments are posted publically on the Newfoundland and Labrador System Operator's OASIS[8] website.

3.0 Asset Reliability

Hydro files a quarterly report[9] with the Board that includes actual forced outage rates[10] and their relation to the rolling 12-month performance of its units, historical reliability performance, and assumptions used in the assessment of resource adequacy. This quarterly report details unit reliability issues experienced in the previous 12-month period and compares performance for the same period year-over-year. The most recent report was submitted on October 30, 2023.[11]

---

[5] As noted within the "*Reliability and Resource Adequacy Study Review* – Labrador-Island Link Update," Newfoundland and Labrador Hydro, April 18, 2023, p. 1, the LIL was commissioned on April 14, 2023.
[6] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[7] Ibid., vols. I and II provide a detailed discussion of the initial modelling approach used. A discussion of changes to the model from the 2018 Filing can be found in 2022 Update.
[8] Open Access Same-Time Information System ("OASIS"), <https://www.oasis.oati.com/NLSO/index.html>.
[9] Hydro's Quarterly Report on Performance of Generating Units can be accessed at <http://pub.nl.ca/indexreportspages/12MonthRollingAverage.php>.
[10] Forced outage rate refers to an input to the Reliability Model that represents the percentage of hours in a year when a unit is unavailable.
[11] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended September 30, 2023," Newfoundland and Labrador Hydro, October 30, 2023. <http://pub.nl.ca/indexreports/12month/From%20NLH%20-%20Q3%202023%20Report%20on%20the%20Rolling%2012%20Month%20Performance%20of%20Hydros%20Generating%20Units%20-%202023-10-30.PDF>.

Hydro continues to take action to address repeat performance issues by conducting broad reviews that frequently involve external experts. Issues are urgently addressed and increased focus is placed on asset reliability.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since the May 2023 Near-Term Report. Updates on these items and any additional items that may impact asset performance in the near term are provided in this report. The intention is to ensure issues affecting reliability have been appropriately addressed as recurring issues can impact unit and system reliability if not managed. The information in Section 3.1 through Section 3.2 of this report provides an overview of the repeat or broader issues. Isolated equipment issues (i.e., those that occur once on a particular unit) are also investigated, with the root cause identified and corrected. These types of issues are reflected in the calculation of derated adjusted forced outage rate ("DAFOR") and derated adjusted utilization forced outage probability ("DAUFOP").

Section 3.1.1 to Section 3.1.3 describe issues—both asset-based and condition-based—that have previously affected generating unit reliability as well as the status of those issues and the actions taken to mitigate against future reliability impacts. The scope is not limited to generating assets (e.g., penstock, boiler tubes, etc.); it also considers environmental challenges impacting operations (e.g., frazil ice conditions). As part of this exercise, the following items have been identified and grouped by facility type:

- Hydraulic Facilities (Section 3.1.1):
  - Continued Monitoring: The penstocks at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility"); and
  - Ongoing Issues: Rotor rim key cracking and rotor rim guidance block defects at the Upper Salmon Hydroelectric Generating Station ("Upper Salmon Station") and Control System reliability at the Granite Canal Hydroelectric Generating Station ("Granite Canal Station").
- Thermal Facilities (Section 3.1.2):
  - New Issues: Air compressors, East Forced Draft Fan motor, fuel oil contamination, Holyrood TGS Unit 1 control valve stem failure, and Fuel Tank 1 inspection;

   - Continued Monitoring: Variable frequency drives ("VFD"), unit boiler tubes, Holyrood TGS Unit 3 turbines steam chest crack;
   - Ongoing Issue: Holyrood TGS Unit 1 and Unit 2 turbine blades and aging Infrastructure; and
   - Resolved Issues: Holyrood TGS Unit 1 electrical issue.
- Gas Turbines (Section 3.1.3):
   - New Issue: Stephenville Gas Turbine alternator cooling fan failure.

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

3.1.1 Hydraulic

3.1.1.1 Bay d'Espoir Penstocks

Condition assessments of Bay d'Espoir Penstocks 1, 2, and 3 were conducted in 2018, which included the completion of three reports prepared by a third-party consultant. These reports have been filed with the Board.[12] In response to the most recent failure of Penstock 1 in September 2019, SNC-Lavalin Group Inc. was engaged to complete an independent, detailed failure analysis of the most recent rupture and an engineering review of the work previously completed by Hatch Ltd. The failure analysis and engineering

---

[12] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018, originally filed with the Board on December 17, 2018, also filed as "Penstock 1 Section Replacement and Weld Refurbishment - Bay d'Espoir Hydroelectric Generating Facility," Newfoundland and Labrador Hydro, December 7, 2022, sch. 1, app G. <http://pub.nl.ca/applications/NLH2022WeldRefurbishment/apps/From%20NLH%20-%20Approval%20of%20Section%20Replacement%20and%20Weld%20Refurbishment%20of%20Penstock%201%20at%20the%20Bay%20d%E2%80%99Espoir%20Hydroelectric%20Generating%20Facility%20-%202022-12-07.pdf>.
"Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019, filed as an attachment to "An Application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures to complete a level 2 condition assessment on Penstocks 1 and 2, and a report on Penstocks 1, 2, and 3 at the Bay d'Espoir Hydroelectric Generating Station — Bay d'Espoir Condition Assessment and Refurbishment Options for Penstocks No. 1, 2, and 3, Report 2 of 3," Newfoundland and Labrador Hydro, March 29, 2019. <http://www.pub.nl.ca/indexreports/2019/From%20NLH%20-%20Bay%20dEspoir%20Condition%20Assessm~Refurbishment%20Options%20for%20Penstocks%20No.%201,%202,%20and%203%20-%20Final%20Report%20-%202019-03-29.PDF>.
"Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019, filed as an attachment to "Application for Approval of Capital Expenditures to Complete a Level II Condition Assessment on Penstocks 1 and 2, and a Report on Penstocks 1, 2, and 3 at the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir") —Bay d'Espoir Condition Assessment and Refurbishment Options for Penstocks No. 1, 2, and 3, Report 3 of 3," Newfoundland and Labrador Hydro, July 30, 2019. <http://www.pub.nl.ca/indexreports/From%20NLH%20-%20Bay%20d'Espoir%20Condition%20Assessment%20and%20Refurbishment%20Options%20-%20Penstocks%20No.%201,%202,%20and%203%20Life%20Extension%20Options%20-%20dated%20July%2030,%202019%20%20-%202019-07-31.PDF>.

review results were also filed with the Board.[13] Hydro subsequently engaged Kleinschmidt to aid in the development of an investment strategy plan for life extension activities related to Bay d'Espoir Penstocks 1, 2, and 3.

In December 2022, Hydro filed its application with the Board for approval of the Bay d'Espoir Penstock 1 section replacement and weld refurbishment project,[14] which the Board subsequently approved in April 2023.[15] Detailed design work for this project is currently underway with construction expected to begin in 2025.

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

The Penstock 2 inspection was completed in May 2023, revealing no major material concerns. In total three new weld indications were discovered and subsequently repaired, all located in areas that had not previously been repaired.

The inspection of Penstock 3 was completed in May 2023. During the inspections, nine new weld indications were discovered and subsequently repaired, all located in areas that had not previously been repaired.

[13] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020. <http://www.pub.nl.ca/indexreports/baydespoir/From%20NLH%20-%20Failure%20of%20Bay%20dEspoir%20Penstock%201%20and%20Plan%20Regarding%20Penstock%20Life%20Extension%20-%202020-06-03.PDF>.
[14] "Penstock 1 Section Replacement and Weld Refurbishment - Bay d'Espoir Hydroelectric Generating Facility," Newfoundland and Labrador Hydro, December 7, 2022.
[15] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 6(2023), Board of Commissioners of Public Utilities, April 12, 2023.

The inspection of Penstock 1 commenced in October 2023. During the initial inspection, 19 new weld indications were identified after testing approximately 30 cans[16] in the area between Can 1 and Can 60. This presented a higher percentage of indications in the area than was typically found in previously completed inspections. Based on this, Hydro expanded the investigation scope to inspect different cans in the same area. The second round of inspection and testing found 14 new weld indications in 30 different cans. Based on the percentage of tested welds having indications, the probability of more indications in untested welds was high and Hydro inspected all remaining welds in that area. A contractor refurbished all welds that exhibited indications; inspection of the remaining welds continued in parallel. Refurbishment activities are complete with both Units 1 and 2 returned to service.

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

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

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

As previously reported,[17] following the replacement of all 16 complete guidance block assemblies in 2021, and consistent with the advice of the original equipment manufacturer ("OEM"), regularly scheduled inspections were completed at 2,000-hour intervals. However, following the discovery of worsening conditions during inspections, the interval between inspections was reduced to 1,000 hours in 2022.

In May 2022, the Board approved Hydro's application to undertake additional work in the 2023 outage season to address the required life extension activities.[18] Subsequent to this Order, Hydro planned various inspections in conjunction with OEM expertise. Along with this expertise, Hydro completed the necessary timed inspections on the affected components and found worsening conditions with each

---

[16] Cans are identified as ~9 foot sections of penstock pipe comprised of two half-cylindrical sections that are welded together to create a full cylinder.

[17] Most recently reported in "Reliability and Resource Adequacy Study - 2023 Update - Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, June 2, 2023, sec. 3.1.1.2.

[18] "Application for Approval for Rotor Rim Shrinking and Stator Recentering at the Upper Salmon Hydroelectric Generating Station," Newfoundland and Labrador Hydro, April 26, 2022 was approved in *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 18(2022), Board of Commissioners of Public Utilities, May 20, 2022.

subsequent inspection. Inspections took place in November 2022, January 2023, and March 2023. Hydro mitigated the risk of failure to the extent possible in the near term; the residual risk that a failure could occur before the execution of the required life extension work scope was ultimately realized in March 2023. Following the advice of the OEM, Hydro made the decision not to return the unit at the Upper Salmon Station to service after the March 2023 inspections until the approved capital program could be successfully executed later in 2023.

Hydro has proceeded with approved capital life extension activities required to remedy the issue, as outlined in the approved application, as well as the necessary corrections to the alignment of the turbine and generator assembly. Unit re-assembly activities are underway; completion of the project is expected prior to the December 1, 2023 Winter Readiness date.

3.1.1.3 Granite Canal Control System

As previously reported,[19] an engineering assessment of the Granite Canal Control System has been completed in response to control system malfunctions experienced when remotely starting and/or stopping the unit at the Granite Canal Station. Modifications to equipment, as well as minor logic changes, were implemented in 2019. Additional hardware and instrumentation modifications were implemented during the maintenance outage in June 2020 to address the findings of the 2019 assessment. While there have not been any starting issues recently, there have been an increased number of outages due to component failures. A further investigation regarding the remaining useful life of the Granite Canal Control System determined that control system hardware, originally installed in 2003 at the time of the unit's commissioning, is either presently or soon-to-be obsolete and will require replacement. This replacement is now reflected in Hydro's capital plan and is planned for inclusion in Hydro's 2026 Capital Budget Application.[20] To ensure the continued reliability of this system until the replacement is complete, a review of necessary spare components was completed and all identified items are available.

[19] "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2022, sec. 3.1.1, p. 7/9–23.
[20] Hydro's 2026 Capital Budget Application is to be filed on July 14, 2025, as per the schedule set out in the "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022, app. B. <http://pub.nl.ca/PU/guidelines/Capital%20Budget%20Application%20Guidelines%20(Provisional)%20-%202021-12-20.PDF>.

Since the May 2023 Near-Term Report, no additional forced outages have occurred as a result of control system issues. Hydro continues to seek opportunities to further mitigate the risk of outages to the unit at the Granite Canal Station until the required life extension work is proposed, approved, and executed.

3.1.2 Thermal

3.1.2.1 Variable Frequency Drives

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

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

During the 2022 outage season, Hydro completed the work to bypass the VFDs on Unit 2. This unit was returned to service without VFDs on the forced draft fans and performed reliably throughout the 2022–2023 winter operating season. Conversion of Unit 1 was not possible in 2022 and 2023 due to higher priority work on assets and the system. Hydro is planning to bypass the VFDs on Unit 1 during the 2024 outage season. In February 2023, Unit 1 experienced a VFD power cell failure during a startup, which occurred during the investigation of electrical issues on this unit.[21] During start-up for the 2023–2024 winter operating season, a number of power cell failures occurred; these power cells were replaced. With the bypass of the VFDs on Unit 2 and Unit 3, Hydro has a good supply of spare power cells to support operation of Unit 1 until it is also bypassed.

Hydro will provide further information on the status of the VFDs in the November 2024 update of this report.

[21] Please refer to Section 3.1.2.3 of this report for additional details.

3.1.2.2 Unit Boiler Tubes

Each of the three thermal generating units at the Holyrood TGS has a boiler that contains tubes. Boiler tube failures are a common issue in thermal power plants due to the inherent design, which requires relatively thin walls for heat transfer that are subjected to high temperatures and stresses. Boiler tubes are inspected annually to verify condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts an annual tube inspection and test program. This program was executed during the 2023 annual outage season. Hydro has determined that, as a whole, boiler tube sections are in generally in good condition; however, tube failures continue to pose a risk. Hydro maintains a 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.

A tube failure occurred on Unit 3 in February 2023. A leak developed inside the furnace in a lower water wall tube where the tube attaches to the sidewall tubes and the lower header. The failed section of the tube was replaced by the boiler service contractor using new tube material drawn from inventory. The unit was offline from February 6 to 18, 2023 to complete the repair. The failed tube section was sent to a metallurgical lab for failure analysis to determine if there were any specific remedial actions to be taken. The results found the failure was a result of thermal fatigue (primary) and corrosion fatigue (secondary). The recommendation was to inspect the other three corner tubes on that boiler. This inspection was completed under the Boiler Condition Assessment and Miscellaneous Upgrades (2023) program[22] and three tubes were proactively replaced as a result of the inspection findings.

Hydro will continue to monitor the status of the unit boiler tubes and provide an update in the November 2024 update of this report.

3.1.2.3 Unit 1 Electrical Issues

On February 3, 2023, Hydro experienced a failure of the phase C bottom potential transformer on Unit 1. Issues continued after replacement and a series of voltage fluctuations and subsequent potential transformer failures occurred. The series of issues were investigated and possible causes were ruled out while trying to establish the root cause. Due to this issue, Unit 1 was either offline or held at 70 MW until March 15, 2023.

[22] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, prog. 4, approved by *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023.

Through the investigation, a number of issues were identified. The first finding was a crack in the porcelain of a 180-ohm resistor. The purpose of this resistor is to mitigate the effect of ferroresonance,[23] which can lead to voltage fluctuations and subsequently the failure of the potential transformers. Due to the age of the equipment, a direct replacement for the resistor was not available, as it is no longer being manufactured. A temporary resistor was put in place to mitigate the effect of ferroresonance. Further testing then discovered a failed resistor in the secondary of the generator grounding transformer. The resistor was replaced with a temporary resistor, as a direct replacement could not be sourced with a reasonable lead time. Unit 1 was then brought online and released for full service on March 15, 2023.

Further corrective actions were completed during the 2023 planned annual outage. On Unit 1, temporary resistors were replaced with industrial resistors. On Unit 2, detailed inspections were completed on the resistors that had failed on Unit 1; no issues were found. Industrial spares for these resistors have been added to inventory to support both Unit 1 and Unit 2. Unit 3 does not have the same design; however, the potential transformers on Unit 3 were replaced in 2023.

Maintenance procedures and frequencies have also been reviewed. The preventive maintenance program on the secondary resistors, grounding transformer, and potential transformer cabinets were updated with additional testing and frequency.

Hydro considers this issue complete.

3.1.2.4 Unit 3 Turbine Steam Chest Crack

In 1998, a crack was discovered in the lower steam chest of the Unit 3 turbine. In 2001, GE completed an external weld build-up repair of the steam chest, which was expected to prevent further crack growth for approximately 15 to 25 years, aligning with the planned retirement of the Holyrood TGS. Regular monitoring of the steam chest crack through non-destructive evaluation techniques had shown no appreciable change in the crack until 2019 when a slight change was observed, 21 years following repair. Additional crack growth was measured in 2021.

Considering the recently measured crack growth rate, Hydro contracted GE in 2022 to perform a fracture mechanics engineering study to determine when further intervention would be required to

[23] Ferroresonance is an abnormal electrical phenomenon that can occur when non-linear electrical elements are present, resulting in unstable voltage and current oscillations. It can cause equipment damage and disruptions in the electrical system. Non-linear elements are those whose electrical impedance changes depending on voltage applied.

ensure continued safe and reliable operation. In February 2023, the results of this study were presented to Hydro indicating that, if worst-case assumptions are validated, intervention may be required in as little as nine operating cycles (start/stop). As identified in the study, failure of the steam chest resulting from this crack would be expected to be "break first" rather than "leak first," resulting in a full release of high-pressure superheated steam into the powerhouse, posing a significant risk to personnel and equipment. This fact necessitated using the most conservative, worst-case model prediction of nine operating cycles.

As a result, additional measurements were made in 2023 during the planned annual outage. The results of these measurements, which showed no further growth, were provided to GE for analysis. This resulted in the unit being released for service for the 2023–2024 winter operating season, with re-inspection planned for the 2024 planned outage season or after eight operating cycles. If results are again favourable in 2024, the ability to operate to the major overhaul scheduled for 2025 may be confirmed; however, crack measurement results could necessitate the requirement to intervene in 2024.

Hydro is working with GE and the OEM, Mitsubishi Power (Hitachi), to formulate plans to complete any necessary repairs, preferably during the 2025 planned overhaul. It is expected that the refurbishment of the steam chest would require several months to complete. If, as a result of the inspection in 2024, repairs are deemed necessary in that year, there would be a risk that Unit 3 may not be available for the December 1, 2024 Winter Readiness date.

Hydro will provide a further update on this developing issue in the November 2024 update of this report.

3.1.2.5 Unit 1 and Unit 2 Turbine Blades

During the major overhaul of the Unit 1 steam turbine in 2021, a crack was discovered in one of the last stage blades ("LSB") on the turbine rotor. GE, the OEM, determined that this crack was an indicator that the LSBs were approaching end-of-life and further cracking would be expected. The LSBs had not been identified as a critical spare and Hydro did not have a spare set of LSBs on hand; therefore, as a short-term solution to enable return-to-service, GE successfully completed a weld repair of the crack. Hydro planned to complete a rotor *in-situ* inspection of the LSBs in 2022 to verify no further cracking and then operate until the planned retirement date of March 2023. A spare set of LSBs was ordered when it was determined that the Holyrood TGS would be required to operate to 2024.[24] This set arrived at the Holyrood TGS in May 2023.

Since Unit 2 and Unit 1 are the same age and have a similar operating history, GE informed Hydro that both units are at risk of LSB failure and need to be addressed as an in-service failure could occur. Hydro submitted and received approval to purchase a second set of LSBs, installing one set on a unit in 2023 and the second set on the other unit in 2024.[25]

Rotor *in-situ* inspections were completed during the spring of 2023 to determine which unit was at the highest risk of failure. These inspections found three cracks on the Unit 2 LSBs and none on the Unit 1 LSBs, indicating that the repairs completed in 2021 on Unit 1 continue to hold. Hydro therefore decided to replace the Unit 2 LSBs during the planned major overhaul in 2023, with planned completion by the fall of 2023. Based on the *in-situ* inspection, Unit 1 returned to service for the 2023–2024 operating season in October 2023, with an approved project to replace the Unit 1 LSBs during the 2024 planned outage season.

While the Unit 2 rotor was at the vendor's shop for LSB replacement, defects were found on the second-last stage blades, which had to be addressed prior to return-to-service. As the second-last stage blades cannot be accessed with an *in-situ* inspection, these defects were not seen during the inspection completed on site. There were no defects found on the second-last stage blades on Unit 1 during the 2021 overhaul. This result was unexpected and no blades were available to enable replacement. Repair and removal options were considered; however, Hydro concluded that the prudent approach would be to expedite the purchase and installation of the second-last stage blades. As a result, the turbine rotor is now scheduled to return to site in late-December 2023 with Unit 2 expected to return-to-service by mid-March 2024.

[24] "At the time of the "Application for Approval to Purchase Last Stage Blades for Holyrood Thermal Generating Station Units 1 and 2," Newfoundland and Labrador Hydro, April 26, 2022, Hydro had made a commitment to have the Holyrood TGS fully available for generation until March 31, 2024, as stated in the "*Reliability and Resource Adequacy Study Review* – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings – Additional Information," Newfoundland and Labrador Hydro, February 4, 2022, p. 7, item 3.

[25] The "Purchase and Replace Last Stage Blades for Units 1 and 2 – Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 29, 2023 was approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 12(2023), Board of Commissioners of Public Utilities, May 5, 2023.

There remains a risk that the Unit 1 rotor will also require replacement of the second-last stage blades. Hydro plans to purchase spare LSBs within the Thermal In-Service Failures program to expedite replacement, should it be deemed necessary.

Hydro will provide an update on this issue in the November 2024 update of this report.

3.1.2.6 Air Compressors

As a result of recent failures, Hydro has two of three air compressors available for service for the 2023–2024 operating season. In order to supply the necessary compressed air to the various systems for which it is required and provide system redundancy, Hydro has secured a 900 CFM[26] portable air compressor to temporarily connect to the system. The portable air compressors create minimal risk to operational reliability but are not ideal for long-term use. These units will remain on site and in service as required until the necessary repairs are completed on the original compressor, which is expected to be after the 2023–2024 operating season.

Hydro will provide an update on this issue in the November 2024 update of this report.

3.1.2.7 Unit 3 East Forced Draft Fan Motor

On October 23, 2023, Unit 3 was in start-up mode when a suspected failure of the East Forced Draft Fan motor occurred. Follow-up electrical testing confirmed that the motor must be refurbished, resulting in Unit 3 being derated to approximately 50 MW until the fan can be returned to service. Hydro is prioritizing this work and completion is expected by November 27, 2023. Hydro will investigate the cause of this failure and take appropriate action to prevent future failures. Hydro is considering the purchase of a spare motor for this fan, which would also be a spare for the Unit 3 West Forced Draft Fan. If deemed necessary, Hydro will proceed with the purchase of a spare motor within the Thermal In-Service Failures project.

Hydro will provide an update on this issue in the November 2024 update of this report.

[26] Cubic feet per minute ("CFM").

3.1.2.8 Fuel Tank 1 Inspection and Refurbishment

On September 14, 2023, as crews were transferring No. 6 fuel oil from the tanker vessel to Tank 1, a small leak was identified on Tank 1. Once containment was complete, offloading recommenced with the No. 6 fuel oil being pumped to Tanks 2, 3, and 4.

The Holyrood TGS is a three-tank operation; Hydro must utilize Tank 2 to facilitate repairs to Tank 1 and to ensure adequate fuel supply for the winter 2023–2024 season.[27] Hydro is actively working to execute the repair and return-to-service of Tank 1 to ensure it is available for future fuel shipments, after which Hydro will proceed with plans to retire Tank 2. At this time, the expected return-to-service date of Tank 1 is under review.

Hydro will provide an update on this issue in the November 2024 revision of this report.

3.1.2.9 Fuel Oil Contamination

Hydro has been experiencing issues with No. 6 fuel oil contamination since Unit 1 returned to service on October 8, 2023. This has resulted in the need for more frequent cleaning of fuel oil strainers and burner tips. Hydro has determined two potential sources of this contamination—the use of Tank 2 in response to the leak in Tank 1 (as discussed in Section 3.1.2.8) and the condition of the recent delivery of No. 6 fuel oil. At this time, it appears that the issue is related to the unplanned use of Tank 2.

The No. 6 fuel oil delivered in September 2023 met Hydro's fuel specification; the ash content was slightly higher than previous deliveries but was within specification. The other likely source is considered to be from Tank 2. By September 2023, Tank 2 had been drained down to minimum storage and removed from service in preparation for clean out and decommissioning in the spring of 2024. When the leak in Tank 1 was discovered, during the filling of this tank from a tanker vessel, it became necessary to transfer the already-delivered No. 6 fuel oil from Tank 1 to Tank 2 and to deliver the remaining No. 6 fuel oil from the tanker vessel into Tank 2, as it could not fit into Tank 3 or Tank 4. As the No. 6 fuel oil in Tank 2 had been consumed down to minimum storage, it is possible that the No. 6 fuel oil added to Tank 2 stirred up the sludge from the bottom of that tank. Tank 2 was the first to be put in service when Unit 1 was started up; as a result, sludge may have been carried down to the Day Tank, causing the contamination issue. A switch of the fuel supply from Tank 2 to Tank 3 has improved the situation. While there initially were occasional periods where the fuel strainers were fouling more quickly than normal,

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

contamination has seemed to subside to a normal level. Hydro plans to continue to use No. 6 fuel oil from Tank 3 until the level is the same as that of Tank 2. The tanks will then be put in service in parallel to allow a controlled consumption of the No. 6 fuel oil in Tank 2. Hydro will monitor contamination closely when Tank 2 is returned to service and take action as required.

To date, this condition has not resulted in any interruptions to service. Hydro is managing the situation through the completion of additional maintenance, as required, and by controlling the consumption of No. 6 fuel oil from Tank 2.

Hydro will provide further information in the November 2024 update of this report.

3.1.2.10 Unit 1 Control Valve Stem Failure

On November 3, 2023, a Unit 1 turbine control valve stem failed in service. Unit 1 has six control valves and should be able to achieve full load, or near full load, with one valve unavailable. Due to a boiler-related issue that will cause a five-day outage on the unit, a load test to confirm available load could not be completed. A load test will be completed once the unit is returned to service. The failed valve will be replaced during the planed Unit 1 turbine outage in 2024; a failure analysis will be completed at that time. There is no reason to expect the failure of another valve stem; however, if a failure were to occur, it would result in a unit derating.

Hydro will continue to monitor this issue and update in the November 2024 update of this report.

3.1.2.11 Aging Infrastructure

In 2021, Hydro completed a Condition Assessment and Life Extension Study of the Holyrood TGS. The study concluded that, as per the "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update"),[28] the Holyrood TGS shall remain available for a "Bridging Period"[29] until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. It is recognized that the majority of the Holyrood TGS assets are 40–50 years old; increased age can result in an increased risk of in-service failures. Recent age-related failures have been experienced on the boilers, turbines, and electrical equipment at the Holyrood TGS. Hydro

[28] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[29] Hydro considers the Bridging Period to be from 2023 to 2030. 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 and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

mitigates this risk through regular overhaul programs on major components, including the boilers, turbines, generators, major pumps, loading arms, increased condition assessment work, and a robust critical spares program. Condition assessment/overhaul work was completed in 2023 on all boilers, the Unit 2 turbine, all generators, two major pumps, and air compressors.

As this condition is ongoing, Hydro will continue to monitor and provide an update in the November 2024 update to this report.

As an input to the assessment of resource adequacy, the forced outage rates for the Holyrood TGS provide a measure of the expected level of availability due to unforeseen circumstances. Assumptions on forced outage rates are updated annually in accordance with Hydro's forced outage rates methodology and Hydro continues to assess a range of projected availabilities for the Holyrood TGS in consideration of the age of the facility and past performance.

3.1.3 Gas Turbines

3.1.3.1 Stephenville Gas Turbine – Alternator Cooling Fan Failure

On July 14, 2023, the Stephenville Gas Turbine tripped due to high vibration while operating in synchronous condense mode. During subsequent test runs, the alternator tripped due to high exciter and alternator temperatures. A visual inspection of the unit determined the vibration trip was caused by the failure of one of the alternator cooling fans.[30] The OEM was engaged to complete more thorough inspections and testing; it was confirmed the alternator cooling fan had failed and additional damage was observed on the stators winding insulation.

Based on the inspections, the OEM recommended that the alternator be removed from the unit. The rotor will be removed from the alternator and sent to the OEM's facility in the United States of America for inspection in November 2023; the stator will be inspected, cleaned, and repaired on site. Work began on October 28, 2023 and the expected return-to-service date for this unit is mid-January 2024; however, if delays are experienced, the return-to-service could be the end of January 2024.

[30] The alternator at the Stephenville Gas Turbine has the cooling fan shrunk onto the rotor shaft, which forces air through the rotor and stator air gap, then through the stator coils and core to remove heat from the alternator. Warm air is then cooled by the alternator cooling system and recirculates through the generator.

3.2 Selection of Appropriate Performance Ratings

3.2.1 Asset Reliability in System Planning

Hydro's asset reliability is a critical component in determining its ability to meet planning criteria for the Newfoundland and Labrador Interconnected System. As an input to the assessment of resource adequacy, unit forced outage rates provide a measure of the expected level of availability due to unforeseen circumstances. Assumptions on forced outage rates of generating units are updated annually in accordance with Hydro's forced outage rates methodology.

The forced outage rates used in Hydro's reliability analysis vary by asset class, ownership, and condition. Appropriate forced outage rates are determined using historical data where available, known unresolved issues, industry data, and scenario-based approaches. The forced outage rate is calculated using different metrics depending on the primary operating mode of the units. For units that primarily operate on a continuous basis, specifically hydroelectric units, the forced outage rate is based on historical DAFOR. For units that primarily operate as peaking units, specifically gas turbine units, the forced outage rate is based on historical DAUFOP.

The Holyrood TGS has been historically operated as a base-load generation facility with all three units generating during the winter operating season. In addition to operating as a generator, Unit 3 has also operated as a synchronous condenser during the summer months and shoulder periods.[31,32] In the 2022 Update, the reliability of the Holyrood TGS was assessed in the context of its ability to bring units online quickly as well as its ability to operate reliably and at sufficient capacity when called upon.[33] Historically, forced outage rates for the three units at the Holyrood TGS have been reported using the DAFOR metric predominately used for units that operate in a continuous (base-load) capacity. As presented in the 2022 Update, there are reliability concerns associated with the operation of the units at the Holyrood TGS in a standby capacity. When considering standby or peaking operations of units at the Holyrood TGS, DAFOR is no longer the most appropriate measure of forced outage rates; rather, DAUFOP is a more appropriate measure, given the frequency of deratings historically experienced by these units. Analyses performed for a range of Holyrood TGS DAUFOP assumptions indicate the

[31] Converting Unit 3 to synchronous condenser capability provides reactive power support to the Island Interconnected System and helps regulate system voltage on the Avalon Peninsula.
[32] Unit 3 requires 96 hours to convert from synchronous condense mode to generate mode.
[33] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.3.1.

sensitivity of supply adequacy to changes in Holyrood TGS availability. Hydro will continue to analyze the operational data to ensure that forced outage rate assumptions for the Holyrood TGS are appropriate.

Forced outage rate assumptions are developed annually to incorporate the most recent data available. Table 1 summarizes the near-term projected availability of Hydro's generating assets considered in the assessment of near-term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

Table 1: Forced Outage Rates for Hydro-Owned Assets

Asset	May 2023 Reliability Metric	November 2023 Reliability Metric
Regulated Hydraulic Units	DAFOR = 2.4%	DAFOR = 3.9%
Non-Regulated Hydraulic Units (Muskrat Falls)	N/A	DAFOR = 3.9%
Holyrood Thermal Units: Base Assumption	DAUFOP = 20%	DAUFOP = 20%
Holyrood Thermal Units: Sensitivity Assumption	DAUFOP = 34%	DAUFOP = 34%
Holyrood Gas Turbine	DAUFOP = 4.9%	DAUFOP = 4.9%
Happy Valley Gas Turbine	DAUFOP = 6.7%	DAUFOP = 4.7%
Stephenville Gas Turbine	DAUFOP = 30%	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%	DAUFOP = 30%
Diesels	DAUFOP = 7.9%	DAUFOP = 6.6%

For units not owned by Hydro, the forced outage rates used in modelling are determined using industry averages provided in the Electricity Canada Generating Equipment Reliability Information System and the NERC Generating Availability Data System. Forced outage rates used for assets owned by a third party in this analysis are presented in Table 2.

Table 2: Forced Outage Rates for Third-Party-Owned Assets

Asset	May 2023 Reliability Metric	November 2023 Reliability Metric
Hydraulic Units	DAFOR = 2.2%	DAFOR = 5.8%
Gas Turbines	DAUFOP = 5.3%	DAUFOP = 6.2%
Corner Brook Cogen	DAUFOP = 20.1%	DAUFOP = 19.2%

Hydro has confirmed with Newfoundland Power that its asset plan includes the retirements of both its Greenhill and Wesleyville Gas Turbines, as they are nearing the end of their service lives. Newfoundland Power has indicated that it intends to run these units until they no longer function. In the absence of a planned retirement date, Hydro has kept these units in the near-term model and decreased the reliability of these units by using a DAUFOP of 30%, in line with what is used for Hydro-owned gas turbines nearing end-of-life (i.e., both Stephenville and Hardwoods Gas Turbines) to ensure Hydro is not over-relying on these units.

Hydro models wind generation stochastically using probability distribution functions developed for summer and winter generation at the Fermeuse and St. Lawrence Wind Projects.

3.2.2 Near-Term LIL Reliability

Between December 2022 and January 2023, Hydro responded to failures resulting from four types of localized issues, each observed on a different section of the LIL. These included:

- Three failed turnbuckles,[34] with a failure rate of less than 1%;
- Two damaged optical ground wire ("OPGW") tower peaks, with a failure rate of less than 0.1%;
- One failed electrode conductor, with a failure rate of 0.2%; and
- Two damaged OPGW tower top plates, with a failure rate of 0.4%.

These issues did not affect Hydro's ability to provide customers on the Island with reliable service during the 2022–2023 winter operating season; all critical repairs resulting from the winter failures have been completed.

Following the necessary repairs, Hydro completed investigations into the four types of issues observed on various sections of the LIL during winter 2022–2023. The investigation results help Hydro understand the root cause of each incident so proactive actions can be taken, where necessary, to mitigate against any impact on the long-term reliability of the LIL. To date, Hydro is ahead of schedule within its capital program to replace the turnbuckles, with all planned year 1 replacements having been completed.[35] This scope of work is approximately 40% complete. For the remaining failures, damage was isolated to system communications cables and the electrode conductor system, which are not required for power to flow and, as a result, would not cause a prolonged power interruption. To address these issues, Hydro has increased real-time monitoring of the ice conditions along the transmission line by installing a weather station in the Labrador Straits; an additional weather station is slated for installation in central

[34] Turnbuckles are present only on dead-end towers (327 or 10% of towers), with each tower having 4 turnbuckles.
[35] Turnbuckle replacement is on a four-year schedule, with year 1 complete.

Labrador in 2025. Hydro has also increased line patrols and the collection of field observation data, as maintenance activities are performed.[36]

In addition, the LIL has continued to operate reliably since it was commissioned on April 14, 2023. Hydro anticipates a controlled 900 MW test will be performed on the LIL in 2024 at the end of the first quarter or the beginning of the second quarter, as system conditions permit. This 900 MW will not test any additional functionality that was not already tested and passed during the 700 MW test.

As for contractual obligations to Nova Scotia, delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery having taken place on August 17, 2021.[37] Delivery of Supplemental Energy[38] commenced in November 2021, with the first physical delivery having taken place on November 1, 2021.[39] As per the Energy and Capacity Agreement, in instances where the LIL is fully unavailable, Hydro is not obligated to deliver the Nova Scotia Block or Supplemental Energy.

3.2.2.1 LIL Assumptions

In previous near-term filings, once modelled as in service, the LIL's availability was modelled with a declining monopole-force outage rate (i.e., improving performance) to capture any testing activities and potential operational unknowns during the first years of operation.[40] This would be normal for a new asset in service.

[36] For further details on the investigations, see "*Reliability and Resource Adequacy Study Review* – Summary of Findings from L3501/2 Failure Investigations," Newfoundland and Labrador Hydro, October 4, 2023.
[37] Pursuant to the Energy and Capacity Agreement between Nalcor Energy and Emera Inc. ("Emera"), the Nova Scotia Block is a firm annual commitment of 980 GWh, supplied from the Muskrat Falls Hydroelectric Generating Facility ("Muskrat Falls Facility") on peak. <https://www.emeranl.com/docs/librariesprovider13/maritime-link-documents/commercial-agreements/amended-and-restated-energy-and-capacity-agreement.pdf?sfvrsn=dec21945_2>.
[38] Supplemental Energy is an amount of energy delivered to Emera in equal annual amounts over each of the first five years of operation of the Muskrat Falls Facility during the months of January to March and November to December during off-peak hours.
[39] The delivery of Supplemental Energy is expected to conclude by March 31, 2026.
[40] In 2021, the monopole forced outage rate was assumed 10% for each pole and was maintained through 2022. The forced outage rate assumption decreased to 5.0% in 2023, 2.5% in 2024, and 1.0% per pole in 2025. It is assumed that the LIL would reach its design criteria monopole forced outage rate of 0.556% per pole in 2026.

As noted in the 2022 Update, the bipole forced outage rate is a key driver for system reliability. Absent any long-term operational experience with the LIL post-commissioning, Hydro recognizes that the previously anticipated bipole forced outage rate of 0.0114% is no longer appropriate.[41,42]

Now that the LIL is commissioned, multiple years of operational experience are required to better inform the longer-term selection of a bipole forced outage rate. In the interim, the bipole forced outage rate will be addressed with a range of upper and lower limits as additional scenarios in the analysis, including a low probability scenario treating the LIL as an “Energy-Only Line,” meaning it is not considered to provide reliability benefits, as well as a highly reliable LIL with a forced outage rate of 1%. As LIL performance statistics become available in the coming years, the forced outage rate range may be narrowed in future filings. For the purpose of this analysis, the base-case assumption is that the LIL is available up to a capacity of 700 MW with a 5% bipole forced outage rate, supported by the generating units at the Muskrat Falls Facility.

3.2.2.2 Relationship between the LIL and Maritime Link

The LIL and the Maritime Link are equipped with runbacks—LIL Power Demand Override[43] and Maritime Link Emergency Power Control[44]—to ensure frequency regulation in the event of contingencies on either link. Consequently, flows on the LIL and the Maritime Link must be coordinated.

In accordance with Hydro’s operating criteria, customers shall not be subjected to risk of under-frequency load shedding (“UFLS”) for single contingencies. When the LIL is in bipole operation, there is no risk of UFLS for loss of a pole, due to pole compensation by the healthy pole and runbacks of the Maritime Link. However, when the LIL is in operation as a monopole during normal operating conditions, pole compensation is not available and the amount of LIL power “sunk” to the Island Interconnected System must be limited. To avoid UFLS, the amount of power sunk must be limited in the range of 15 MW to 50 MW, depending on system conditions. Under emergency operating conditions, higher power flows will be permitted. It is assumed that if a pole were to trip offline during the winter

[41] “Reliability and Resource Adequacy Study – 2022 Update,” Newfoundland and Labrador Hydro, October 3, 2022, vol. I, sec. 4.2.1.
[42] The monopole forced outage rate is not a significant driver for LIL reliability when assuming a capacity of 700 MW, given the ability for each pole to be loaded to 1.5 times its rated capacity on a continuous basis (675 MW). Please refer to Section 3.2.2.2, which differentiates monopole operation during normal operation versus emergency operation.
[43] Power Demand Override is a special protection system of the LIL that activates following certain contingencies on the Maritime Link and in the Nova Scotia Power Inc. (“Nova Scotia Power” or “NS Power”) System.
[44] Emergency Power Control is a special protection system of the Maritime Link that activates following certain contingencies on the LIL and Island Interconnected System.

operating period, the emergency operating limits would be adhered to, resulting in a significant increase of LIL energy available to be sunk to the Island Interconnected System until system conditions improve. However, if the emergency monopole limits were put in-place, UFLS would have to be accepted for the loss of the monopole, even though it would be considered a single contingency event.

Due to the interdependent relationship of the LIL and the Maritime Link, the availability of the Maritime Link also impacts the amount of power delivered to the Island Interconnected System via the LIL. If the Maritime Link were not available, this would in turn reduce the amount of LIL energy that can be brought to the Island Interconnected System.

3.2.3 Holyrood TGS Near-Term Operating Philosophy

In its 2022 Update, Hydro stated that, in advance of each winter operating season, every effort would be made to have all three Holyrood TGS units available for operation until new generation can be placed into service. Therefore, for the purposes of this report, it was assumed that all three units at the Holyrood TGS are available through the near-term study period (2024–2028), with the exception of winter 2023–2024, as Unit 2 is assumed unavailable until mid-March 2024.[45] While every effort is being made to return the unit to service earlier than currently estimated, for winter 2023–2024, Unit 1 and Unit 3 are expected to be online at a minimum generation of 70 MW and Unit 2 is assumed to be unavailable.

Post-winter 2023–2024, the operation of the Holyrood TGS will be determined in advance of each winter operating season, depending on system conditions at that time. For reliability modelling purposes, all three units will be assumed available (either operating, in standby mode, or a combination of both), with the exception of the 2023–2024 winter operating season.

3.3 Asset Retirement Plans

3.3.1 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.

The 2022 Update established the need for on-Island backup generation to support the LIL until new resources are integrated into the system. In addition, there is a need for reliable backup generation to

[45] Please refer to Section 3.1.2.5 for additional details regarding the unavailability of Unit 2 at the Holyrood TGS.

address the capacity shortfall on the Island Interconnected System in the event of an extended LIL outage. To address the immediate need to backup the LIL on an interim basis, as noted above, as per the 2022 Update, Hydro has communicated that the Holyrood TGS shall remain available for a "Bridging Period"[46] until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.[47] In advance of each winter operating season, every effort will be made to have all three units at the Holyrood TGS available for operation until an adequate replacement can be put in service. Beyond such time, the plan remains that Unit 3 at the Holyrood TGS will continue to operate as a synchronous condenser, while Unit 1 and Unit 2 are scheduled to be shut down and decommissioned.

3.3.2 Hardwoods and Stephenville Gas Turbines

The Stephenville Gas Turbine consists of two 25 MW gas generators, commissioned in 1975. The Hardwoods Gas Turbine 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.

The analysis completed for the 2022 Update supported the retirement of the Stephenville Gas Turbine by March 31, 2024 at which point the backup supply for the area served by the Stephenville Gas Turbine was planned to be addressed by the addition of a 230/66 kV, 40/53.3/66.7 MVA power transformer at the Bottom Brook Terminal Station and subsequent reconfiguration at the Stephenville Terminal Station.[48,49]

In light of a combination of load growth, an increase in hydro generation forced outage rates, the forced unavailability of Unit 2 at the Holyrood TGS during the 2023–2024 winter operating season, the risks of

[46] The primary, readily available supply options during this Bridging Period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.
[47] As directed in "Newfoundland and Labrador Hydro - Reliability and Resource Adequacy Study Review Planned Reports, Studies and Analyses - Further Comments and Directions," Board of Commissioners of Public Utilities, October 12, 2023, Hydro is assessing the impacts and viability of Holyrood TGS operation beyond 2030, including impacts to its operational and capital plans.
[48] This addition will provide capacity via the 66 kV network in the event of the loss of the existing 230/66 kV transformer T3 at the Stephenville Terminal Station or the loss of 230 kV transmission line TL209.
[49] A project to complete these modifications was included in the "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. II, tab 14. <http://pub.nl.ca/applications/NLH2021Capital/applications/From%20NLH%20-%202021%20Capital%20Budget%20Application%20-%20Volume%20II%20-%20Revision%202%20-%202020-11-02.PDF>.

aging asset availability, and the near-term positive performance of the Stephenville Gas Turbine, Hydro is continuing operation of the Stephenville Gas Turbine beyond 2024. At this time, a recommended revised retirement date has not been concluded; this will be determined in advance of the next Resource Adequacy Plan to be filed in spring 2024.

With respect to the Hardwoods Gas Turbine, asset availability at these facilities is significantly improved over the levels previously observed.[50] In its 2022 Update, Hydro recommended that the Hardwoods Gas Turbine remain in service until 2030 to support the Island Interconnected System in the event of a LIL outage or until such time that sufficient alternative generation is commissioned and both the Holyrood TGS and Hardwoods Gas Turbine are no longer required to support generation reserves in a contingency scenario.

In instances where Hydro models these units as continuing to be in service, it will continue to model these assets with a DAUFOP of 30% to ensure there is not an overreliance on these assets in the near term to maintain the reliability of the system. To ensure an appropriate balance of cost and reliability in this matter, Hydro will undertake necessary preventive and corrective maintenance work to ensure these units are available to the Island Interconnected System.

In all scenarios through the study period (2024–2028), both the Hardwoods and Stephenville Gas Turbines are assumed to remain in service through the study period.[51]

3.4 New and Aging Asset Considerations

With the LIL in its early operation, the early level of reliability is anticipated to be lower than the long-term level of reliability, due to expected sources of potential failures associated with new assets, such as defective components or manufacturing issues. This phenomenon is known as the “bathtub curve.” This concept, which theorizes a relationship between equipment age and failures, has been presented by The Liberty Consulting Group (“Liberty”) in previous reliability assessments.

[50] This reduction in the requirement to operate is primarily attributed to the availability of the LIL, the Maritime Link, and Hydro’s ability to use a portion of the capacity available under its Capacity Assistance Agreement with Corner Brook Pulp and Paper Limited (“CBPP”) as ten-minute reserve.
[51] Stephenville Gas Turbine is assumed in-service by mid-January 2024. Please refer to Section 3.1.3.1 of this report for additional details.

> Equipment failures in relation to equipment age generally exhibit a “bathtub-shaped curve.” Incidents of failure tend to be high when equipment is new and again after 30-50 years, depending on equipment type.[52]

As Figure 1 shows, the bathtub curve has three regions—the first has a decreasing failure rate due to early failures that are found and corrected contributing to improved reliability, the middle is a constant failure rate due to normalized frequency of expected failures, and the last is an increasing failure rate due to end-of-life failures.

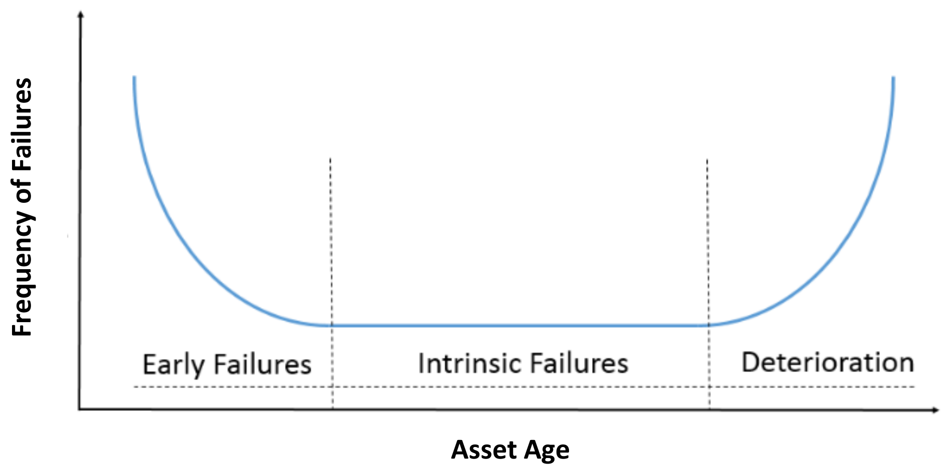

Figure 1: Bathtub Curve[53]

Early failures on the LIL have largely arisen due to items that were not considered during project design that have come to light during testing and early years of operation; as the bathtub curve describes, this is normal for the operation of new assets early in life. Examples of such items include aspects of LIL software, LIL hardware, as well as with the overland line. In terms of LIL software, Hydro continues to work with GE to complete the final version of software. For LIL hardware, Hydro is undertaking efforts to replace DCCTs[54] to mitigate performance issues that include measurement drifting in cold temperature conditions.

---

[52] “Supply Issues and Power Outages Review, Island Interconnected System, Executive Summary of Interim Report,” The Liberty Consulting Group, April 24, 2014, sec. D, p. 57. <http://www.pub.nl.ca/applications/IslandInterconnectedSystem/files/reports/LibertyInterimReportApril24-2014.pdf>.

[53] James Carroll, Alasdair MacDonald, Oswaldo Barrera Martin, David McMillan, and Roozbeh Bakhshi “Offshore Wind Turbine Sub-Assembly Failure Rates Through Time,” November 2015. <https://www.researchgate.net/publication/305000920_Offshore_Wind_Turbine_Sub-Assembly_Failure_Rates_Through_Time/link/577ebc3c08ae69ab8820ea1c/download.>.

[54] Direct-current current transformers (“DCCT”).

Through operational experience and monitoring, Hydro will gain an understanding of the effectiveness of potential investments to upgrade LIL structures. Such investments have and will be made in consideration of risk and value-based assessments that will be better informed by other critical factors that impact system reliability, including response times for emergency repairs. To this end, Hydro is undertaking efforts to understand the forced outage rate of the LIL based on operational data in consideration of the bathtub curve, the failures experienced during early operation, and the engineering solutions that are being implemented to mitigate failure modes and improve reliability. As stated previously, it is too early to draw firm conclusions; however, Hydro will continue to collect and explore operational data to take the most effective measures to improve LIL performance. As directed by the Board, Hydro will provide a report including an update on work being undertaken, and scope and schedule for planned work on studying potential enhancements for the LIL in the first half of 2024.[55]

Hydro also has aging assets that are within the third region of the bathtub curve. This is evident in the factors affecting recent generating asset reliability, as discussed in Section 3.1, as well as the increase in performance ratings, as identified in Section 3.2.1. Long-Term Asset Planners are monitoring the health of the assets and identifying major investment requirements and unit performance ratings are updated accordingly in Hydro's near-term generation adequacy modelling and reflected in the results in Section 8.0 of this report.

3.5 Additional Stakeholder Requests

Through various filings not related to the *Reliability and Resource Adequacy Study Review* proceeding, Hydro received three requests from Newfoundland Power related to near-term reliability, which are addressed in this report accordingly. The questions and corresponding answers are summarized as follows:

Request No. 1

> How did Hydro determine it would be appropriate to operate the Holyrood TGS with two units online as opposed to three? Please provide any analysis used by Hydro to make the decision.[56]

---

[55] "Newfoundland and Labrador Hydro - Reliability and Resource Adequacy Study Review Planned Reports, Studies and Analyses - Further Comments and Directions," Board of Commissioners of Public Utilities, October 12, 2023.
[56] Hydro's 2024 Capital Budget Application, request for information NP-NLH-012. <http://pub.nl.ca/applications/NLH2024Capital/requests/From%20NP%20-%20RFIs%20-%20NP-NLH-012%20to%20NP-NLH-015%20-%202023-10-06.PDF>.

Hydro's Response

As discussed in the 2022 Update and the May 2023 Near-Term Report, Hydro will make every effort to have all three units at the Holyrood TGS available as backup generation until 2030, or until new generation sources can be constructed. As Hydro gains operational experience from the LIL, Hydro will balance reliability while being conscious of costs borne by ratepayers in planning Holyrood TGS operations.

For the purposes of the 2023–2024 winter operating season, only two units at the Holyrood TGS are available for generation for this coming winter.[57] This has been modelled in Hydro's Reliability Model accordingly and the results are presented as Scenario 1 in Section 8.1. Should the LIL operate as anticipated, up to a 700 MW capacity with a 5% bipole forced outage rate, Hydro begins to exceed the applicable planning criteria of less than 2.8 LOLH for the 2023–2024 winter operating season.

As stated in Section 3.2.3, post-winter 2023–2024, the operation of the Holyrood TGS will be determined in advance of each winter operating season, depending on system conditions at that time. For reliability modelling purposes, all three units will be assumed available (either operating, in standby mode, or a combination of both), with the exception of the 2023–2024 winter operating season.

Request No. 2

> Please explain the extent to which Hydro would expect rotating customer outages in the event of a LIL outage during peak winter conditions with two, as opposed to three, Holyrood TGS units online. In the response please explain whether the third Holyrood TGS unit would need to be brought online to address a LIL outage during peak winter conditions and, if so, how long it would take to bring a third Holyrood TGS unit online.[58]

Hydro's Response

The forced outage rate assumptions discussed in Section 3.2 of this report ensure Hydro is not over-relying on individual generating units to meet peak winter conditions. The forced outage rates are modelled under probabilistic circumstances, which include unit availability, unit derates, and weather variations—a much more robust means of determining system reliability than deterministic analysis.

[57] Please refer to Section 3.1.2.5 of this report for additional details.
[58] Hydro's 2024 Capital Budget Application, request for information NP-NLH-013. <http://pub.nl.ca/applications/NLH2024Capital/requests/From%20NP%20-%20RFIs%20-%20NP-NLH-012%20to%20NP-NLH-015%20-%202023-10-06.PDF>.

During the 2023–2024 winter operating season, only two units at the Holyrood TGS are available for generation. In consideration of this, and the assumed unavailability of the remaining assets in Hydro's fleet, Hydro is marginally violating the 2024 annual near-term reliability criteria in the base-case scenario (Scenario 1) assuming the LIL has a forced outage rate of 5%. Assessing the monthly results, the month of January 2024 has the highest risk of lost load hours of 1.8 hours, with a corresponding unserved energy of 155 MWh. The risk is lower in February 2024 and diminishes significantly in March 2024. Compared to 2025, when three units at the Holyrood TGS are assumed available, the annual LOLH reduces to 1.30, well within acceptable planning criteria. There is no violation of near-term reliability criteria for all years in the base-case with three units at the Holyrood TGS available and in years where the LIL has a forced outage rate less than 5%.[59]

The Holyrood TGS, as designed, is not configured to synchronize to the grid quickly, having a unit recall time in excess of 24 hours.[60] To better position the Holyrood TGS as a backup supply resource, Hydro recommends continued investment in capital improvements to the facility to ensure continued operation potentially through 2030. During anticipated periods of high demand, the Holyrood TGS may be placed online early in anticipation of a potential need to improve the responsiveness and therefore reliability of the unit(s).[61]

As stated in Section 3.2.3, the operation of the Holyrood TGS will be determined in advance of each winter, depending on system conditions at that time. For reliability modelling purposes, with the exception of this 2023–2024 winter operating season, all three units will be assumed available (either operating, in standby mode, or a combination of both).

[59] Please refer to Section 8.0 of this report for all analysis results.
[60] As described in the "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, p. 24/9–18 and p. 25/1–4.
[61] As described in response to PUB-NLH-275.

Request No. 3

Newfoundland Power requested that Hydro assess the implications of a further GSU transformer failure in the Near-Term Reliability Report.

> The assessment should specifically address the implications of a further GSU transformer failure at Holyrood during the upcoming 2023-2024 winter season and how Hydro would address such an event.[62]

Hydro's Response

The forced outage rates included in the analysis inherently include unit transformer outages, as they are a direct function of historical generation issues, which include past transformer failures. On that basis, Hydro considers the base-case (Scenario 1) to be more reflective of likely outcomes for this coming winter and in the near term. However, Hydro has added a scenario to account for the additional transformer outage scenario that was requested (see Scenario 1A in Section 8.0).

Through a supplemental application to its 2023 Capital Budget Application, Hydro has been granted approval to purchase a spare GSU transformer to add to its existing spare transformer, which is currently undergoing repairs.[63] While the existing spare transformer is not compatible with the transformers at the Holyrood TGS, and as Holyrood TGS Unit 2 is not anticipated to be available until mid-March 2024, the transformer ("HRD T2") can be used as a direct replacement for the Unit 3 transformer. Bus duct modifications would be required for HRD T2 to be used for Unit 1. Recent experience suggests that a transformer change out can be completed within 5-6 weeks.[64] For the purposes of this scenario analysis, a unit at the Holyrood TGS was forced out for six weeks during the coldest winter period (January to mid-February) to represent the worst-case scenario (see Scenario 1A in Section 8.0). Should this unlikely scenario occur, it would represent a near-term planning criteria violation during the month of January.

---

[62] "NLH-2023 Capital Budget Supplemental Application – Approval of the Purchase of a Spare Generator Step-Up Transformer, Newfoundland Power's Comments," Newfoundland Power Inc., September 29, 2023.

[63] "Purchase Spare Generator Step-Up Transformer," Newfoundland and Labrador Hydro, September21, 2023 was approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 28(2023), Board of Commissioners of Public Utilities, October 18, 2023.

[64] This timeline could be impacted by contractor and heavy-hauling equipment availability and/or major weather events.

The Board had an additional request:

Request No. 4

The Board requested:

> . . . information on the implications of the unavailability of Holyrood Unit 2 for near-term reliability and resource adequacy for the upcoming 2023-2024 winter, including the assumptions on forced outage rates for various assets, the load forecast and various scenarios illustrating the implications of various levels of unavailability of assets and the anticipated system reliability in each scenario, and additional actions and/or measures Hydro it is taking for this upcoming winter due to unavailability of Holyrood Unit 2.[65]

Hydro's Response

All requested information has been included in this report.

4.0 Load Forecast

4.1 Load Forecasting

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 and Labrador Interconnected System, rural isolated systems, as well as by utility load[66] and industrial load.[67] 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.

4.2 Economic Setting

The Newfoundland and Labrador economy slightly contracted (-1.7%) in 2022; however, most economic indicators showed moderate to strong growth. Total employment increased 4.4% in 2022 and the

[65] "Newfoundland and Labrador Hydro – 2023-2024 Winter Readiness Planning Report," Board of Commissioners of Public Utilities, October 24, 2023.
[66] Residential and General Service loads of Newfoundland Power and Hydro.
[67] Hydro currently has six Industrial customers on the Island and two Industrial customers in Labrador.

unemployment rate fell to 11.2%, the lowest annual rate since 1976. The provincial population also continues to experience strong growth, with an increase of 1.3% from July 2022 to July 2023, marking the largest annual increase, on an actual basis, since 1972. Capital investment and housing starts continued to rebound from 2020 and 2021 levels, while other economic indicators, such as household disposable income, improved throughout the year.

A significant increase in the price of crude oil production increased the overall value of oil production by 33.6 %, which was partially offset by a decrease in the value of mineral shipments due to low mineral prices. The seafood sector continued to be a significant contributor to the provincial rural economy, with the value of fish landings reaching a new record high in 2022, up 19.2% over 2021.

Looking forward through the medium-term (i.e., one to five years) there are several developments that will positively influence provincial economic activity. Several major projects (i.e., Bay du Nord, West White Rose, and hydrogen developments) should increase investment and contribute to employment gains. Further aquaculture developments proceeded in the province in 2022, with Grieg NL SeaFarms Ltd. stocking its first marine sites in Placentia Bay. This project was released from environmental assessment in 2018 and is expected to be fully operational by 2025. This company was also the successful proponent for the Bays West Aquaculture Development project and has begun the initial steps to develop the area. Continued increased interest in aquaculture is expected to expand the overall fishing and aquaculture industry.

The mining sector continues to have encouraging developments. Marathon Gold Corporation continues to advance its Valentine Gold Project in central Newfoundland, with construction activities starting in the first quarter of 2023 and first production expected in the first quarter of 2025. Vale Newfoundland and Labrador (“Vale”) continues to proceed with the development of two underground mines at the Voisey’s Bay Mine site. First production from one of the underground mines occurred in 2021 and extraction from the second has begun. This project is a long-term source of nickel concentrate for the Long Harbour Processing Plant.

Over the medium-term, real GDP is forecast to increase, primarily due to increased mineral production and investment growth. Most other economic indicators are also forecast to show growth. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that lower oil production will hinder overall economic growth in 2023 while the mining sector will remain a bright spot for the province in the year ahead. Non-residential activity in the near term, stemming from major projects, will continue to contribute to positive economic growth.[68,69]

While the current provincial outlook for 2023 remains soft, underlying local market conditions for electric power operations through the medium and longer term, in the context of provincial energy requirements, suggest significant increases in energy requirements throughout the forecast period, which is partially driven by actions to combat climate change resulting in a shift towards electrification.[70]

4.3 Forecast Load Requirements

The customer load requirement component of Hydro's near-term load forecast was developed using forecasted load requirements provided by Hydro's Industrial customers and Hydro's load forecast for Newfoundland Power and its rural service territories.[71,72] Hydro relied on these inputs to determine a forecast of customer energy and coincident demand for the Island Interconnected System, the Labrador Interconnected System, and the Newfoundland and Labrador Interconnected System.

Changes in forecast load requirements since the May 2023 Near-Term Report include a minor change in forecast Island Interconnected System power and energy requirements across the medium term. Forecast Island Interconnected System peak demand requirements are more comparable in the short term than previously forecast and 1.9% higher through the medium term, with forecast energy requirements 2.7% higher through the medium term. Forecast power and energy requirements for the Island Interconnected System are higher than previously forecast primarily as a result of stronger economics, in particular stronger population growth, and electrification forecasts.

Hydro's near-term Labrador Interconnected System load forecast continues to reflect the unresolved power supply constraints in Labrador, which are anticipated to be addressed through the ongoing *Network Additions Policy – Labrador Interconnected System* process. The Labrador Interconnected

[68] Beata Caranci, Derek Burleton, Rishi Sondhi, and Marc Ercolao, "Provincial Economic Forecast – The Pulse is Slowing, But the Beat Goes On", TD Economics, September 2023. <https://economics.td.com/provincial-economic-forecast#nl>.
[69] "Macroeconomic Outlook - Canada's economy is beating expectations, but for how long?" RBC Economics, June 8, 2023. <https://thoughtleadership.rbc.com/canadas-economy-is-beating-expectations-but-for-how-long/>.
[70] The energy outlook is conditioned by electricity prices in which the customer rate impacts of the Muskrat Falls Project are assumed mitigated.
[71] Hydro's rural service territory includes independently completed load forecasts for the Island Interconnected Rural Service Territory, the Labrador East Rural Service Territory, and the Labrador West Rural Service Territory.
[72] The underlying electricity rate aligns with the Government of Newfoundland and Labrador's rate mitigation target of 14.7 cents per kWh, escalating at 2.25% per year.

System forecast demand requirement is decreased in the short- and medium-terms compared to the May 2023 Near-Term Report, reflecting the assumption that work related to the *Network Additions Policy – Labrador Interconnected System*[73] will be finalized by 2024 and the current temporary agreement with an existing non-firm customer will be terminated.[74,75] Energy requirements through the short and medium term are also lower (3.3%) compared to the May 2023 Near-Term Report. Forecast energy requirements are lower primarily as a result of excluding the current non-firm customer, with a small change in industrial requirements also impacting total energy requirements. The demand forecasts by system are provided in Table 3, Table 4, and Table 5.

Table 3: Island Interconnected System ("IIS") Peak Demand Forecast (MW)[76]

	2024	**2025**	**2026**	**2027**	**2028**
Utility[77]	1,513	1,542	1,554	1,571	1,589
Industrial Customer	172	182	182	182	182
IIS Customer Coincident Demand	1,685	1,725	1,736	1,753	1,772
IIS Transmission Losses and Station Service	118	117	117	118	117
Total IIS Demand	**1,802**	**1,842**	**1,853**	**1,872**	**1,889**

Table 4: Labrador Interconnected System ("LIS") Peak Demand Forecast (MW)[78]

	2024	**2025**	**2026**	**2027**	**2028**
Utility	141	142	143	143	144
Industrial Customer	306	306	306	306	306
LIS Customer Coincident Demand	447	447	448	449	450
LIS Transmission Losses and Station Service	29	29	29	29	29
Total LIS Demand	**476**	**476**	**477**	**478**	**479**

[73] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*. <https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf>.
[74] The existing customer's contract is for temporary service for a data centre operation.
[75] Following the conclusion of work on the *Network Additions Policy – Labrador Interconnected System*, it is expected that new contracts with non-firm customers will be established.
[76] Numbers may not add due to rounding.
[77] The utility demand forecast includes approximately 22 MW of potential interruptible load in 2025.
[78] Numbers may not add due to rounding.

Table 5: Newfoundland and Labrador Interconnected System ("NLIS") Peak Demand Forecast (MW)[79]

	2024	2025	2026	2027	2028
NLIS Customer Coincident Demand	2,104	2,144	2,157	2,175	2,194
NLIS Transmission Losses and Station Service	145	144	144	144	144
Total NLIS Demand	**2,249**	**2,288**	**2,301**	**2,319**	**2,338**

5.0 System Energy Capability

To reliably serve its customers, Hydro maintains minimum storage limits to ensure that it can meet customer energy requirements. Historically, these limits represent the point at which Holyrood TGS generation would require maximization to ensure Hydro could continue to meet customer requirements in consideration of the historical dry sequence. The 2023–2024 limits were developed considering maximized delivery of power from the Muskrat Falls Facility, supplemented by available Recapture Energy from the Churchill Falls Generating Station over the LIL. The 2023–2024 analysis assumed that only two units at the Holyrood TGS would be online and operating at minimum load during the 2023–2024 winter operating season. The minimum storage methodology was updated to ensure Hydro's reservoirs could continue to provide reliable service to customers at the lowest possible cost in an environmentally responsible manner.

The limits do not consider the availability of imports over the Maritime Link, though imports can provide an additional opportunity to supplement energy in storage and economically reduce the amount of thermal generation required to maintain sufficient energy in storage. Regular assessments of storage at a reservoir-level basis are also completed to ensure that each hydraulic generating unit remains capable of producing at full-rated output through the winter period. At this time, Hydro does not foresee using production from standby generation to support reservoir levels.

At the end of October 31, 2023, the total system energy in storage was 2,113 GWh, 1,065 GWh above the minimum storage limit of 1,048 GWh for October 2023.

Chart 1 plots the 2022 and 2023 storage levels, the maximum operating level storage, and the 20-year average aggregate storage for comparison.

[79] Numbers may not add due to rounding.

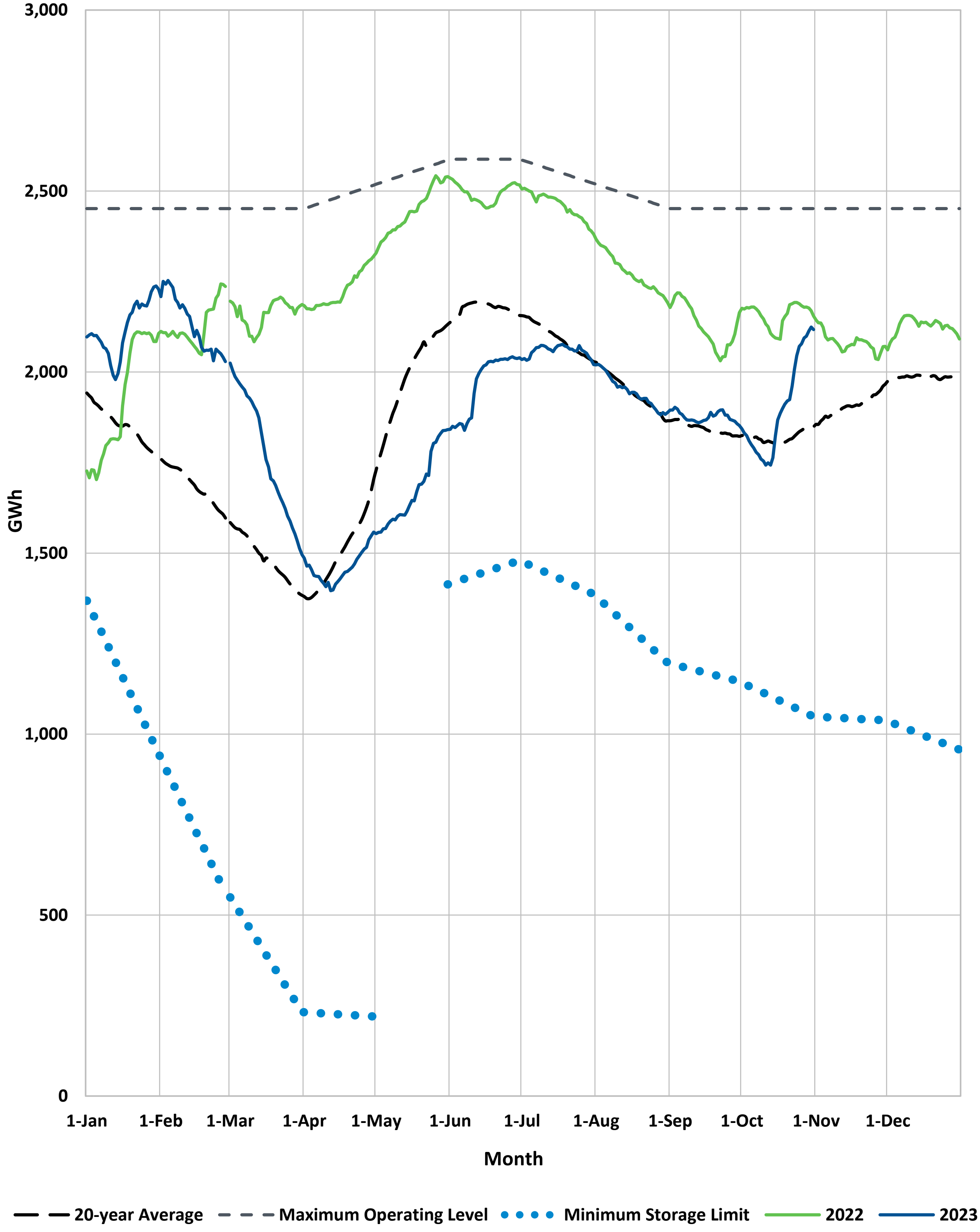

Chart 1: Total Energy Storage for October 31, 2023

6.0 Availability of Imports

In some previous near-term filings prior to 2023, import scenarios were contemplated as sensitivities to cases; that is, firm imports of 50 MW, 100 MW, and 150 MW from December to March in winters where the LIL is assumed unavailable with an associated forced outage rate intended to serve as a proxy for anticipated potential interruptions to the import. The intent of the analysis was to demonstrate the effect on the system if the capacity was available in the requested amounts. As previously stated, the availability of such capacity is dependent on the ability to contract with a counterparty to provide firm capacity, which is not guaranteed.

When considering firm import of electricity across the Maritime Link to meet the reliability of the Newfoundland and Labrador Interconnected System, there are two main components to consider—firm transmission and firm capacity.

6.1 Transmission and Market Access[80]

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

1) **Nova Scotia**: To acquire energy from Nova Scotia, Hydro requires only its existing Maritime Link transmission access as Nova Scotia Power has the ability to deliver energy to the Nova Scotia-Newfoundland and Labrador border, resulting in less risk to curtailments.
2) **New Brunswick**: To acquire energy from New Brunswick, two transmission paths need to be considered—New Brunswick and Nova Scotia transmission.
    - The transmission path inside New Brunswick to deliver energy to Nova Scotia shares the interface between New Brunswick and Prince Edward Island. New Brunswick has firm contracts to supply firm energy and balance the load in Prince Edward Island. The transmission interface limit is 300 MW and the firm transmission is contracted by New Brunswick to meet their contractual obligations to Prince Edward Island.

[80] Please refer to Hydro's response to NP-NLH-093 of this proceeding.

- The interface between the New Brunswick/Nova Scotia transmission systems is often congested. In a February 2023 integrated resource plan update from Nova Scotia Power, it discussed firm imports on this interface

> Update on potential Firm Imports from New Brunswick:
> - Firm import capacity from NB Power[81] continues to be unavailable due to transmission system limits and committed firm exports to Prince Edward Island.
> - NS Power[82] received confirmation from NB Power that the Reliability Tie, without additional transmission investment further into New Brunswick, is not anticipated to provide additional firm import capacity to NS.[83]

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 has priority at that interface for imports for their native load.

It is important to note that there are also Island transmission constraints in delivering imported energy via the Maritime Link to the Avalon Peninsula.[84]

6.2 Firm Energy Availability[85]

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

- **Nova Scotia**: According to the 2023 Evergreen Integrated Resource Plan,[86] Nova Scotia Power continues to plan to retire coal by 2030 and does not have surplus capacity in their system to

[81] New Brunswick Power Corporation ("NB Power").
[82] Nova Scotia Power Inc. ("NS Power").
[83] Nova Scotia ("NS").
[84] Please refer to "*Reliability and Resource Adequacy Study Review* – Avalon Supply (Transmission) Study," Newfoundland and Labrador Hydro, October 31, 2023.
[85] Please refer to Hydro's response to NP-NLH-093 of this proceeding.
[86] "Powering A Green Nova Scotia, Together – 2023 Evergreen Integrated Resource Plan – Updated Action Plan and Roadmap," Nova Scotia Power Inc., August 8, 2023 <https://irp.nspower.ca/files/key-documents/annual-evergreen-materials/Evergreen-IRP-Update-to-IRP-Action-Plan-and-Roadmap-2023.pdf>.

export. Nova Scotia Power heavily relies on coal to meet their capacity requirements in the winter and is looking to replace its coal plants with total capacity of 1,081 MW by 2030 to meet federal government regulations.

- **New Brunswick**: NB Power filed a ten-year Integrated Resource Plan in 2023,[87] at which time it outlined the requirement to build additional capacity builds to meet load growth and decarbonisation plans. This past winter, New Brunswick also reached an all-time peak demand, which could further reduce near-term surplus capacity.
- **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, an annual auction four years in advance is insufficient to plan for the reliability of the Island Interconnected System.

In October 2023, Hydro confirmed with both Nova Scotia Power and New Brunswick 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.

7.0 Capacity Assistance

7.1 Vale Capacity Assistance Agreement

For all scenarios, it is assumed that the contract for capacity assistance with Vale is renewed for each winter season in the study period. The rationale is that if Hydro was in a loss of load situation, these existing units could provide capacity assistance. For the 2023–2024 winter operating season, Hydro is working with Vale on a capacity assistance agreement, which is expected to be finalized prior to December 1, 2023.

7.2 CBPP Capacity Assistance Agreement

For CBPP Capacity Assistance, Hydro has been working with CBPP on a long-term capacity assistance agreement. Pending the completion of the terms of the long-term capacity assistance agreement and

[87] "2023 Integrated Resource Plan – Pathways to a Net-Zero Electricity System," New Brunswick Power Corporation. <https://www.nbpower.com/media/1492536/2023_irp.pdf>.

the corresponding application to the Board, CBPP has agreed to provide capacity assistance to Hydro under the same terms that had been approved in Board Order No. P.U. 4(2021).[88] In all scenarios, it is assumed that the CBPP Capacity Assistance Agreement remains in place throughout the study period.

8.0 Analysis Results

The following subsections provide a description of the six scenarios considered and the anticipated system reliability in each scenario (i.e., LOLH, EUE, and NEUE results).

8.1 Scenario Analysis

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

- **Scenario 1 (Base-Case):** Assumes that the LIL will be available at 700 MW for the study period with a 5% bipole forced outage rate. This case assumes a DAUFOP of 20% for the Holyrood TGS.
    - **Scenario 1A:** Varies from Scenario 1 by simulating a GSU transformer failure at a HRD Unit (January 1-February 15) in winter 2024.[89]
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS forced outage rate to the 2021 actual of 34%.
- **Scenario 3**: Varies from Scenario 1 by increasing the bipole forced outage rate to 10% through the study period.
- **Scenario 4**: Varies from Scenario 1 by decreasing the bipole forced outage rate to 1% through the study period.
- **Scenario 5:** Varies from Scenario 1 by considering the LIL to be an energy-only line through the study period (2024–2028) (i.e., the LIL provides no reliability benefits).

8.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 8.2.1 and 8.2.2 provide the results of the annual and monthly analyses, respectively.

[88] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 4(2021), Board of Commissioners of Public Utilities, January 26, 2021.
[89] This scenario was requested in “NLH-2023 Capital Budget Supplemental Application – Approval of the Purchase of a Spare Generator Step-Up Transformer – Newfoundland Power’s Comments,” Newfoundland Power Inc., September 29, 2023.

8.2.1 Annual Assessment Results

Annual LOLH, EUE and NEUE results are provided in Table 6. The basis for comparison of the results is Hydro's existing LOLH criterion of not more than 2.8 hours per year.[90] The LIL reliability remains a key factor in the ability to economically achieve proposed planning criteria. Hydro is committed to reassessing its reliability criteria as part of the next Resource Adequacy Plan update, scheduled for the spring of 2024, as Hydro continues to gather information while working with stakeholders.

Table 6: Annual LOLH, EUE, and NEUE Results

LOLH (hours)	**2024**	**2025**	**2026**	**2027**	**2028**
Scenario 1: LIL at 700 MW, LIL Bipole FOR[91] = 5%, Holyrood TGS DAUFOP = 20%	**2.89**	1.30	1.46	1.69	1.87
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	**7.53**	1.30	1.46	1.69	1.87
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	**5.43**	**3.49**	**3.86**	**4.29**	**4.60**
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	**5.78**	2.59	**2.88**	**3.36**	**3.71**
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.60	0.26	0.29	0.35	0.39
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	**57.71**	**26.22**	**28.84**	**33.31**	**37.43**

EUE (MWh)	**2024**	**2025**	**2026**	**2027**	**2028**
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	224	93	107	128	143
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	691	93	107	128	143
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	470	288	314	359	404
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	454	189	213	254	286
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	48	18	23	27	30
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	4525	1896	2129	2512	2931

NEUE (ppm)[92]	**2024**	**2025**	**2026**	**2027**	**2028**
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	19	8	9	11	12
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	60	8	9	11	12
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	41	24	27	30	34
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	39	16	18	21	24
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	4	2	2	2	3
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	391	161	180	212	245

In general, LOLH, EUE, and NEUE results for all scenarios throughout the study period (2024–2028) have increased materially since the May 2023 Report largely due to a 1.5% increase from regulated Hydraulic DAFOR, as well as increases due to load growth that are increasing the demand on the Island Interconnected System.

---

[90] LOLH is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. For Hydro, the acceptable criteria is no more than 2.8 hours of lost load annually.

[91] Forced outage rate ("FOR").

[92] 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.

The results of Scenarios 1 through 5 indicate that the unavailability of Unit 2 at the Holyrood TGS until mid-March 2024 and the Stephenville Gas Turbine until mid-January 2024 increases the risk of lost load and unserved energy during the 2023–2024 winter operating season in all scenarios where the LIL forced outage rate is 5% or greater or if the Holyrood TGS DAFOR is similar to what was experienced in 2021. In Scenario 1 (Base-Case), LOLH surpasses the acceptable planning criteria by 0.09 hours. Not surprisingly, this risk of lost load and unserved energy increases resulting in an LOLH violation, should a second unit at the Holyrood TGS be forced out for six weeks during the coldest period of winter, as represented in Scenario 1A. The risk of lost load and unserved energy remains throughout the near term for all scenarios where the LIL forced outage rate is greater than 5% or if the Holyrood TGS DAFOR is similar to what was experienced in 2021.

As new assets are being reliably integrated into the system and aging assets are being used as backup support in the interim, this risk will likely not diminish until new generation is added. As load growth increases, driven largely by electrification, the risk of lost load and unserved energy will as well. If projected load growth is higher than currently forecast, the projected shortfall will also increase. This also presents a risk to any new customer seeking firm capacity, as Hydro is significantly capacity-constrained in the near term. The amount of risk is highly dependent on the LIL bipole forced outage rate and the availability of the Holyrood TGS. These results support continued, measured investment to maintain the Holyrood TGS and the Hardwoods and Stephenville Gas Turbines as reliable generation stations in the near term, as all measures of backup would reduce, but not eliminate, the risk.

Scenario 5 indicates that if LIL reliability is such that it is not counted upon for capacity (i.e., considered an energy-only line), there is a significant risk to system reliability in the near term, despite the continuation of the Holyrood TGS and the Hardwoods and Stephenville Gas Turbines. This is consistent with the results reported in the May 2023 Near-Term Report. With that said, the Muskrat Falls Project Assets are now all commissioned and integrated into the Island Interconnected System, with the LIL currently tested to 700 MW.

8.2.2 Monthly Assessment Results

Table 7 to Table 16 provide analyses of LOLH and EUE for each year by month. The monthly analyses provide additional detail that assists in examining the complexity of the changing power system that would not necessarily be apparent from an analysis of the annual results only. Completing monthly analysis allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for a better understanding of the drivers of the annual results. This type of analysis is used by NERC-regulated utilities to complement long-term reliability assessments.

As expected, the results of Scenarios 1 through 5 indicate that both LOLH and EUE grow as the unavailability of the Holyrood TGS and/or the LIL increases, with the highest risk largely in the month of January and, to a lesser extent, in the month of February for all years. The availability of the LIL—backed up by the Holyrood TGS and the Hardwoods and Stephenville Gas Turbines—helps to reduce the risk of lost load and unserved energy in circumstances where the LIL forced outage rate is greater than 5%.

The results of Scenario 5 indicate that if the LIL reliability is such that it is not counted on for capacity, both LOLH and EUE are exceedingly high in the winter months. With that said, it is unlikely that the LIL will not be available in any capacity throughout the entire study period (2024–2028).

Table 7: Monthly LOLH for 2024[93]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	1.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	5.1	2.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	3.0	1.4	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	3.6	1.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	35.7	14.1	4.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.8

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

Table 8: Monthly EUE for 2024[94]

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	155	45	14	0	0	0	0	0	0	0	0	9
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	512	155	14	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	292	108	39	1	0	0	0	0	0	0	1	29
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	312	95	28	0	0	0	0	0	0	0	1	18
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	32	10	3	0	0	0	0	0	0	0	0	2
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	3069	960	290	5	1	0	1	0	0	0	6	192

Table 9: Monthly LOLH for 2025[95]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	0.6	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	1.5	1.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	1.2	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	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: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	12.6	6.8	2.7	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.2	3.7

Table 10: Monthly EUE for 2025[96]

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	47	23	9	0	0	0	0	0	0	0	0	13
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	140	75	28	2	0	0	0	0	0	0	2	40
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	99	44	17	1	0	0	0	0	0	0	1	27
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	10	5	1	0	0	0	0	0	0	0	0	2
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	1000	447	169	7	2	0	2	0	0	0	9	258

[94] Monthly results may not add up to annual results due to rounding.
[95] Monthly results may not add up to annual results due to rounding.
[96] Monthly results may not add up to annual results due to rounding.

Table 11: Monthly LOLH for 2026[97]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	0.7	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	1.6	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	1.3	0.8	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	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: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	13.8	7.5	3.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	4.2

Table 12: Monthly EUE for 2026[98]

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	56	26	9	0	0	0	0	0	0	0	0	15
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	150	81	33	2	1	0	0	0	0	0	1	46
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	107	52	19	1	0	0	0	0	0	0	0	32
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	11	6	3	0	0	0	0	0	0	0	0	3
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	1117	503	190	9	2	1	3	0	0	1	2	302

Table 13: Monthly LOLH for 2027[99]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	0.8	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	1.8	1.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	1.6	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	16.0	8.4	3.6	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.1	4.7

[97] Monthly results may not add up to annual results due to rounding.
[98] Monthly results may not add up to annual results due to rounding.
[99] Monthly results may not add up to annual results due to rounding.

Table 14: Monthly EUE for 2027[100]

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	66	29	12	1	0	0	0	0	0	0	0	18
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	172	91	39	2	1	0	0	0	0	0	1	52
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	132	59	24	1	0	0	0	0	0	0	0	37
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	15	6	2	0	0	0	0	0	0	0	0	4
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	1334	576	233	10	2	1	3	0	0	1	4	346

Table 15: Monthly LOLH for 2028[101]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	0.9	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	2.1	1.1	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	1.8	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	18.7	8.0	4.0	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.1	6.0

Table 16: Monthly EUE for 2028[102]

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	78	28	13	0	0	0	0	0	0	0	0	23
Scenario 1A: Simulating Transformer Failure at HRD Unit (Jan 1-Feb 15) during Winter 2024	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	205	84	41	3	0	0	0	0	0	1	1	68
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	157	58	26	1	0	0	0	0	0	0	1	43
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	16	6	2	0	0	0	0	0	0	0	0	5
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	1604	575	262	11	3	1	4	1	0	2	8	459

[100] Monthly results may not add up to annual results due to rounding.
[101] Monthly results may not add up to annual results due to rounding.
[102] Monthly results may not add up to annual results due to rounding.

9.0 Conclusion

To ensure that it has a fulsome understanding of the resultant system reliability, in the analysis presented in this report, Hydro has demonstrated a range of system reliability metrics considering assets:

- In service as planned;
- In service at levels that have been experienced historically, and;
- Not in service.

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. The range of scenarios are used to assess system reliability under a range of potential system conditions, however Scenario 1 (Base-Case) is what Hydro expects to occur in the near term.

Since May 2020, Hydro has reported planning criteria violations in sensitivities to the base-case in its Near-Term Reports; however, Hydro has maintained the appropriate level of system reliability throughout each subsequent winter with no supply impact to customers. The number of violations identified in the scenarios in this report has increased and Scenario 1 (Base-Case) indicates a marginal violation to planning criteria.

As previously identified by both Hydro and Liberty, the availability of power over the LIL remains essential to system reliability.[103] Heading into the 2023–2025 winter operating season, the LIL is available for operation up to 700 MW; a material improvement compared to the 2022–2023 winter operating season when, at that time, the LIL had not yet passed commissioning and was restricted to a capacity of 450 MW. In addition, the four issues encountered on the LIL during this past winter did not affect Hydro's ability to provide customers on the Island with reliable service and all critical repairs resulting from the failures have been completed.

In addition, the reliability of the backup sources of supply also remains essential to system reliability until new generation sources can be constructed. To help ensure reliable service for customers in the near term, Hydro has committed to maintaining the Holyrood TGS, the Hardwoods Gas Turbine, and the

[103] Until there have been multiple years of operational experience for the LIL to better inform the selection of a bipole forced outage rate, the LIL bipole forced outage rate will be addressed with a range of upper and lower limits. As the LIL performance statistics become available in the coming years, the bipole forced outage rate range can be narrowed in future filings.

Stephenville Gas Turbine[104] as generating facilities until new generation can be integrated to the system.[105] Hydro recognizes that the forced unavailability of Unit 2 at the Holyrood TGS and the Stephenville Gas Turbine into this coming winter will put an additional strain on the system; however, Hydro is actively working towards returning these units to service earlier than what has been assumed in the scenario analysis. As additional support for system reliability, Hydro is also actively working on capacity assistance agreements in advance of the coming winter.

Lastly, while acquiring a firm import contract for reliability during the 2023–2024 winter operating season is not feasible in advance of this winter, 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, should they be required.

Hydro remains focused on the completion of its annual maintenance program to ensure the reliability of its existing assets and infrastructure in advance of the 2023–2024 winter operating season as well as monitoring the health of the assets and identifying major investment requirements in the near term to ensure continued, reliable, least-cost supply for customers.

[104] In light of a combination of factors, Hydro is recommending the continued operation of the Stephenville Gas Turbine beyond 2024. At this time, a recommended revised retirement date has not been concluded; this will be determined as part of the next Resource Adequacy Plan.
[105] An update to the recommended retirement dates for backup generation will be addressed in the next Resource Adequacy Plan.