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June 2, 2023

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

Attention: Cheryl Blundon
Director of Corporate Services & Board Secretary

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

Further to the Board of Commissioners of Public Utilities' ("Board") correspondence of October 13, 2016, requesting semi-annual reports on May 15[1] and November 15 each year on generation adequacy for the Island Interconnected System, enclosed please find Newfoundland and Labrador Hydro's Near-Term Reliability Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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[1] On May 9, 2023, Newfoundland and Labrador requested a brief extension to June 2, 2023 for the filing of its May 2023 Near-Term Reliability Report. The Board granted Hydro's request for an extension on May 10, 2023.

Reliability and Resource Adequacy Study 2023 Update

Volume II: Near-Term Reliability Report – May Report

June 2, 2023

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

With the commissioning of the Muskrat Falls Project Assets, the uncertainty of Labrador-Island Link ("LIL") reliability, and significant expected load growth brought on by federal and provincial efforts to decarbonize the electricity industry in Canada by 2035, the Newfoundland and Labrador Interconnected System is undergoing a critical transitional period. To meet the needs of its customers while managing these uncertainties, 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 resource adequacy and reliability and provides the results of the probabilistic resource adequacy assessment of the Newfoundland and Labrador Interconnected System for the 2023–2027 study period. The analysis was conducted consistent with the methodology proposed in the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document,"[1] which provides modelling "practices, requirements, and recommendations needed to perform high-quality probabilistic resource adequacy assessments."

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 LIL.

The *"*Probabilistic Assessment Technical Guideline Document" suggests a more granular view of resource adequacy, focusing on monthly and annual LOLH and EUE reporting. By conducting this type of analysis, the impact of system changes is more easily observed than using only an annual analysis. As LOLH and EUE do not currently have generally acceptable criteria, unlike the generally accepted loss of

[1] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016.
[2] NEUE provides a measure relative to the size of the assessment area. It is defined as: [(Expected Unserved Energy)/(Net Energy for Load)] × 1,000,000 with the measure of per unit parts per million ("ppm").

load expectation ("LOLE") criterion of 0.1, the quantified results show how the loss of load changes based on system conditions rather than for comparison against a threshold.

The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform decisions on the most appropriate resource options as system requirements evolve.

Given the evolving nature of the Newfoundland and Labrador Interconnected System, an analysis was conducted for the period from 2023 to 2027 to provide the Board of Commissioners of Public Utilities ("Board") with insight into the evolution of system reliability as the Muskrat Falls Project Assets are reliably integrated. With respect to the Muskrat Falls Project, since Hydro's "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – November Report" ("November 2022 Report"),[3] the LIL was successfully tested and operated to 700 MW[4] and considered commissioned on April 14, 2023.[5]

As has been observed in prior near-term reliability reports, the results of Hydro's analysis indicate that reliable operation of the LIL is shown to provide significant system reliability benefits even at low power transfer levels. While power transfer over the LIL is expected throughout the 2023–2024 winter operating season, Hydro has prepared this analysis in a manner consistent with prior analyses by considering and analyzing system reliability through the entire reporting period, with an assumption that the LIL capacity will not be counted upon for the reporting period (i.e., rather considered as an energy-only line) to provide a fulsome view of potential system reliability. In addition, a range of potential LIL bipole forced outage rates was considered, consistent with the analysis conducted in the "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update")[6] and the November 2022 Report.

[3] "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2022.
[4] A controlled 900 MW test will be performed during the winter of 2023–2024.
[5] "*Reliability and Resource Adequacy Study Review* – Labrador-Island Link Update," Newfoundland and Labrador Hydro, April 18, 2023.
[6] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

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"),[7] with updates to reflect current system assumptions.[8]

Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these assessments are posted publically on the Newfoundland and Labrador System Operator ("NLSO") OASIS[9] website.

3.0 Asset Reliability

Quarterly reports are filed with the Board that include actual forced outage rates and their relation to:

- The rolling 12-month performance of its units;[10]
- Past historical rates; and
- Assumptions used in the assessment of resource adequacy.

These reports detail unit reliability issues experienced in the previous 12-month period and compare performance for the same period year-over-year. The most recent report was submitted on April 28, 2023.[11]

Hydro continues to take action to address repeat performance issues by conducting broader 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 filing its November 2022 Report. Updates on these items, and any additional items that may impact asset performance in the

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[7] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[8] 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 "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. I.
[9] Open Access Same-Time Information System ("OASIS").
[10] Quarterly Report on Performance of Generating Units.
[11] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2023," Newfoundland and Labrador Hydro April 28, 2023.

near term, are provided in this report. The intention is to ensure issues affecting reliability have been appropriately addressed as recurring issues can significantly impact unit and system reliability if not appropriately managed. The information in Sections 3.1.2 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").

The following sections describe issues—both asset- 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) but 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:
    - Continued Monitoring: Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") penstocks; and
    - Ongoing Issues: Granite Canal Hydroelectric Generating Station ("Granite Canal") Control System reliability and Upper Salmon Hydroelectric Generating Station ("Upper Salmon") rotor rim key cracking and rotor rim guidance block defects.
- Thermal Facilities:
    - New Issues: Unit 1 electrical issue, Unit 3 turbines steam chest crack, and Unit 1 and Unit 2 turbine last stage blades;
    - Continued Monitoring: Variable frequency drives ("VFD");
    - Ongoing Issue: Unit boiler tubes; and
    - Resolved Issues: Boiler feed pump motor issues and T2 power transformer failure.
- Gas Turbines:
    - Resolved Issue: Stephenville Gas Turbine Alternator Glycol Pump 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 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 all three Bay d'Espoir penstocks. In December 2022, Hydro filed its application with the Board for approval of its 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 Bay d'Espoir. A more prescriptive operating regime has also remained in place for Units 1 and 2, given the history of Penstock 1. 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 material concerns. The remaining 2023 inspections for the Bay d'Espoir Penstocks are scheduled in accordance with the approved unit outage schedules, with Penstock 3 commencing in late May 2023 and Penstock 1 in mid-October 2023.

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[12] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018, filed with the Board on December 17, 2018; "Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019, filed with the Board on March 29, 2019; and "Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019, filed with the Board on July 30, 2019.

[13] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

[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.

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 circumstances.

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

As previously reported, during the planned annual preventative maintenance checks in August 2021, a significant crack on 1 of 16 rotor rim guidance blocks was discovered. The discovery of this crack prompted Hydro to expand its inspection scope to include the use of non-destructive testing ("NDT") methods to assess the remaining rim guidance blocks. This expanded inspection revealed that over 35% (6 of 16) of the rim guidance blocks exhibited cracking.

In consultation with the original equipment manufacturer ("OEM") for the equipment, it was determined that the cracking was beyond repair and block replacement was immediately required before the unit could be placed back into reliable service. As recommended by the OEM, all 16 blocks were replaced during a forced extension to the planned outage. The Upper Salmon unit was returned to service on October 22, 2021.

Following the replacement of all 16 complete guidance block assemblies in 2021, consistent with the advice of the OEM, regularly scheduled inspections were completed at 2,000-hour intervals. The intent of these inspections was to address any additional guide block fretting corrosion and weld cracks, as the guide block replacement completed in 2021 was a near-term life extension action until the more permanent long-term solution to address rotor/stator alignment issues could be planned and implemented. However, following the discovery of worsening conditions during inspections, the interval between inspections was reduced to 1,000 hours in 2022. The Board approved an application by Hydro to undertake additional work to address the required life extension activities.[16]

Since the previous filing, inspections have continued at 1,000-hour intervals. During inspections in November 2022 and January 2023, dislodged fragments of the rotor rim laminations and welds from the guide block assemblies were discovered inside the rotor spider. These findings were not consistent with historical inspection findings. At the time of this initial discovery, the limited quantity of rim laminations found to be broken did not result in immediate concerns for the continued reliable operation of the unit

[16] "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.

because there was still sufficient material in the rim dovetail slots to maintain contact with the guidance rim assemblies.

During the most recent inspection in March 2023, significant quantities of broken rim laminations were found in various locations around the unit, being discovered in 8 of 16 guidance block assemblies. The extent of the damage was shown to vary; however, there are two guidance block assemblies with less than 25% of the remaining contact surface area between the key and remaining laminations.

Following this discovery, the OEM was consulted and advised that given the known condition of the unit and the worsening results from recent inspections, continued operation of the unit in this state should not continue. Although Hydro had mitigated the risk of failure to the extent possible in the near term, there was a residual risk that a failure could occur before the execution of the required life extension work scope, with this risk ultimately being realized. Following the advice of the OEM, Hydro completed the necessary risk review and made the decision not to return the Upper Salmon unit to service until the approved capital program can be successfully executed later in 2023.

This recommendation has resulted in a forced outage to the Upper Salmon unit, commencing in March 2023 and continuing for the foreseeable future, while preparation work is ongoing for the capital project. Work has commenced on the approved capital project with a return-to-service date estimated for the fall of 2023.

3.1.1.3 Granite Canal Control System

As previously reported,[17] a thorough 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 Granite Canal unit. 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 has been completed. It has been 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

[17] "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.

will require replacement. This replacement is now reflected in Hydro's capital plan and required capital work will be proposed as part of the capital budget process in the applicable future year following the conclusion of front-end engineering design. To ensure the continued reliability of this system until such a time as the replacement is complete, a thorough review of necessary spare components was completed and all identified items are available.

Since the November 2022 Report, additional critical spares have been identified and procured to mitigate the risk of outages to the Granite Canal unit until the required life extension work is proposed, approved, and executed.

3.1.2 Thermal

3.1.2.1 Boiler Feed Pump Motors

On October 25, 2020, Hydro experienced a failure of the Holyrood TGS Unit 1 boiler feed pump west. Following a forced outage and derating, the pump was returned to service on November 16, 2020. Following the failure, a TapRooT investigation determined the root cause of the pump failure.

As a result of the investigation findings, control logic modifications have been implemented that trip a boiler feed pump if the suction valve moves off the open position. This will prevent the recurrence of this issue. The other recommended corrective actions from the investigation are also complete. Preventive maintenance strategies have been modified to include a mechanical assessment of critical components of 4,160 V motors. Interlocking logic has been reviewed for all 4,160 V motors at the Holyrood TGS.

Hydro considers this issue resolved.

3.1.2.2 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.

Since installation, Hydro has dealt with significant reliability issues related to this equipment despite engaging the OEM for annual preventive maintenance work and following OEM recommendations to take significant mitigating measures to keep the drives clean and dry during outage periods and to pre-energize the VFDs before start-up.

In September 2021, as a result of the significant reliability issues and long lead times to restore or replace failed power cells (a vital component of the drives that has been prone to frequent failure), Hydro decided to bypass the VFDs on Unit 3 before the 2021–2022 winter operating season. This work was successful and Unit 3 performed reliably throughout the season.

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 due to shop resource loading and outage schedules. Hydro is preparing plans to bypass the VFDs on Unit 1 during the 2023 outage season. In February 2023, Unit 1 experienced a VFD power cell failure during a start-up that was undertaken during the investigation of electrical issues that occurred on this unit.[18] Hydro will provide further information on the status of the VFDs in the November 2023 update of this report.

3.1.2.3 T2 Power Transformer Failure – Unit 2

The Unit 2 power transformer, T2 ("HRDT2"), failed on November 12, 2021. The failed transformer was replaced with the onsite spare. The unit was returned to service for the commissioning of the spare transformer on January 12, 2022 and released for service by the NLSO on January 13, 2022. The installed spare transformer operated reliably for the 2021–2022 winter operating season; however, at a reduced output of 150 MW. Hydro subsequently performed a pump replacement that increased the output of this unit to 170 MW in advance of the 2022–2023 winter operating season.

The investigation into the cause has been completed with the support of Hitachi Energy (ABB) and Doble Engineering and a definitive root cause has not been determined. However, due to corrosive Sulphur being present in HRDT2, Hydro developed a follow-up action plan for 2022 and 2023 to mitigate the corrosive Sulphur risk in other transformers in Hydro's transformer fleet known to contain corrosive Sulphur.

For HRDT2, Hydro considers this issue resolved.

3.1.2.4 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

[18] See Section 3.1.2.5 of this report for further details.

relatively thin walls for heat transfer subjected to high temperatures and stresses. Boiler tubes are inspected annually to verify their condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts a thorough annual tube inspection and test program. This program was executed during the 2022 annual outage season and is scheduled for 2023. 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 thorough selection of spare tube material and a contract with an experienced boiler contractor for the provision of emergency repairs in the event of tube failures.

A tube failure did occur 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 are 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, which is already planned under the Boiler Condition Assessment and Miscellaneous Upgrades (2023) Program[19] and will be executed in 2023.

3.1.2.5 Unit 1 Electrical Issues

On February 3, 2023, Hydro experienced a failure of the phase C bottom potential transformer on Unit 1 at the Holyrood TGS. 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.

Through the investigation, a number of problems were identified. The first finding was a 180-ohm resistor in series with the primary of the potential transformers that had a crack in the porcelain, causing

[19] "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.

the resistance to fluctuate. The purpose of this resistor is to mitigate the effect of ferroresonance,[20] which can lead to voltage fluctuations and subsequently the failure of the potential transformers. A direct replacement for the resistor was not available, due to the age of the equipment, as it is no longer being manufactured. A temporary resistor was put in place on the secondary of the potential transformers to mitigate the effect of ferroresonance. Further testing then showed a voltage signal that followed a pattern typical of a floating ground reference and upon investigation, a failed resistor was identified 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.

The remaining corrective actions are planned for 2023. The temporary resistors on the secondary of the potential transformers are to be replaced with proper industrial resistors and the temporary resistor in the secondary of the grounding transformer will be replaced with an industrial resistor. These activities will be completed during the 2023 planned annual outage. Maintenance procedures and frequencies are under review and instrument transformer testing methods will be investigated to develop an in-depth testing plan for potential transformers to better assess their condition. Investigation into the cause of the failure, as well as identification of spare parts issues, will be completed. Hydro will provide a further update on this issue in the November 2023 update of this report.

3.1.2.6 Unit 3 Turbine Steam Chest Crack

A crack was discovered in the Unit 3 turbine’s lower steam chest in 1998. In 2001, GE completed an external weld build-up repair of the steam chest that 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 (“NDE”) techniques had shown no appreciable change in the crack until 2019 when a slight change was observed. 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 ensure continued safe and reliable operation. The results of this study were presented to Hydro in February 2023 and indicated that intervention may be required in as little as nine operating cycles (start/stop) if worst-case assumptions are validated. As identified in the study, failure of

[20] 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.

the steam chest resulting from this crack would be expected to be "break first" rather than "leak first," which would result in a full release of high-pressure superheated steam into the powerhouse and pose a significant risk to personnel and equipment. This fact necessitates using the most conservative, worst-case model prediction of nine operating cycles.

As a result, additional measurements will be made in 2023 during the planned annual outage. The results of these measurements will be provided to GE for analysis. With favourable results (little or no crack growth), the unit may be returned to service for another season and measurements repeated in 2024. If results are again favourable at that time, the ability to operate to the major overhaul scheduled for 2025 may be confirmed; however, crack measurement results could necessitate the requirement to intervene earlier.

Preparations are underway to complete the 2023 steam chest inspection, which is scheduled for completion in June 2023. The results of this inspection will be immediately sent to GE for review. Hydro is working with GE and with the OEM, Mitsubishi Power (Hitachi), to formulate plans to complete any necessary repairs. It is expected that the refurbishment of the steam chest would require several months to complete. If, as a result of the inspection, repairs are deemed necessary, there would be a risk that Unit 3 may not be available for the winter readiness date of December 1, 2023. Hydro will provide a further update on this developing issue in the November 2023 update of this report.

3.1.2.7 Unit 1 and Unit 2 Turbine Last Stage Blades

In 2021 during the major overhaul of the Unit 1 steam turbine, 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 are approaching end-of-life and that 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, GE successfully completed a weld repair of the crack as a short-term solution to enable return-to-service. 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 Holyrood TGS would be required to operate to 2024.[21] This set arrived at Holyrood TGS in May 2023.

Since Unit 2 is the same age as Unit 1 and has a very similar operating history, GE informed Hydro that both units are at risk of LSB failure and need to be addressed before an in-service failure could occur.

Hydro submitted and received approval to purchase a second set of LSB, installing one set on a unit in 2023 and the second set on the other unit in 2024.22 Rotor in-situ inspections were completed during the spring of 2023 to determine which unit is 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 continue to hold. Hydro has 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 will return to service for the 2023–2024 operating season and the Unit 1 LSBs will be replaced in 2024 during the outage season. Hydro will provide an update on this issue in the November 2023 update of this report.

3.1.3 Gas Turbines

3.1.3.1 Stephenville Gas Turbine – Alternator Glycol Pump Failure

On September 27, 2022, the Stephenville Gas Turbine tripped while operating in synchronous condenser mode. The cause of the trip was determined to be the failure of a redundant glycol pump on the alternator cooling system. The failure of the pump was the result of a failed bearing and resulted in internal damage to the pump and its connected piping. This also resulted in the loss of approximately 4,000 litres of coolant (50/50 water-glycol mixture), which required environmental remediation that was completed by October 3, 2022.

To determine the scope of the repair required to return the unit to service, inspections were completed on the alternator and its cooling system. It was determined that the alternator and remaining glycol pump were suitable for continued operation. To ensure the system was clean, it was flushed several

[21] "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.

[22] 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.

times until no debris remained in the system. The unit was returned to service on October 17, 2022. The damaged glycol pump was repaired and returned to service on January 24, 2023.

Hydro considers this issue resolved.

3.2 Selection of Appropriate Performance Ratings

3.2.1 Consideration of 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.[23] Assumptions on forced outage rates of generating units are updated annually in accordance with Hydro's forced outage rates methodology.[24]

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, 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 the historical DAFOR. For units that primarily operate as peaking units, specifically gas turbine units, the forced outage rate is based on the 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.[25,26] In the 2022 Update, the reliability of the Holyrood TGS was assessed in the context of its ability to bring units online

[23] 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.

[24] In this report, Hydro deviated from the forced outage rate methodology as outlined in the 2022 Update when selecting forced outage rates for its hydroelectric units and for the Holyrood Gas Turbine. In both cases, Hydro believed the result of the prescribed methodology did not accurately represent the risk of unit outage. For the hydroelectric units, Hydro used the ten-year, capacity-weighted average DAFOR, which is higher than the three-year DAFOR, increasing the forced outage rate to more appropriately represent the risk of failure in the near term. For the Holyrood Gas Turbine, Hydro used a scenario-based approach to estimate the forced outage rate.

[25] 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.

[26] Unit 3 requires 24 to 36 working hours to convert from synchronous condense mode to generate mode.

quickly, as well as its ability to operate reliably and at sufficient capacity when called upon.[27] 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 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.

Industry information made available through Electricity Canada and NERC is used to determine forced outage rates for units not owned by Hydro.

Forced outage rate assumptions are developed annually to incorporate the most recent data available. Table 1 summarizes the 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	Reliability Metric
Hydraulic Units	DAFOR = 2.4%
Holyrood Thermal Units – Base Assumption	DAUFOP = 20%
Holyrood Thermal Units – Sensitivity Assumption	DAUFOP = 34%
Holyrood Gas Turbine	DAUFOP = 4.9%
Happy Valley Gas Turbine	DAUFOP = 6.7%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%
Diesels	DAUFOP = 7.9%

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

[27] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.3.1.

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	Reliability Metric
Hydraulic Units	DAFOR = 2.2%
Gas Turbines[28]	DAUFOP = 5.3%
Corner Brook Cogen	DAUFOP = 20.1%

Hydro has confirmed with Newfoundland Power Inc. ("Newfoundland Power") that their asset plan includes retirements of both their 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 until they reach 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 LIL Reliability

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.[29] As noted in the 2022 Update, the bipole forced outage rate is a key driver for system reliability, and 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.[30] The monopole forced outage rate is not a

[28] Gas Turbines that are known to be reaching end-of-life (i.e., Greenhill and Wesleyville Gas Turbines) are modelled using a DAUFOP of 30%.
[29] 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.
[30] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. I, sec. 4.2.1.

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).

Now that the LIL is commissioned, multiple years of operational experience are required to better inform the 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. 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 LIL is assumed to be available at a reduced capacity of 700 MW with a 10% bipole forced outage rate through 2023, with a 5% bipole forced outage rate thereafter, supported by the full availability of the generating units at the Muskrat Hydroelectric Generating Facility.

3.2.2.2 Relationship between LIL and Maritime Link

The LIL and the Maritime Link are equipped with runbacks, LIL Power Demand Override[31] and Maritime Link Emergency Power Control,[32] 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, 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 30 MW to 50 MW, depending on system conditions. Under emergency operating conditions, higher power flows may be permitted.

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.

[31] 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") System.
[32] Emergency Power Control is a special protection system of the Maritime Link that activates following certain contingencies on the LIL and Island Interconnected System.

Delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery having taken place on August 17, 2021.[33] Delivery of Supplemental Energy[34] commenced in November 2021, with the first physical delivery having taken place on November 1, 2021. 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.

3.3 Asset Retirement Plans

3.3.1 Holyrood Thermal Generating Station

The Holyrood TGS Units 1 and 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. The three units combined 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 address the capacity shortfall on the Island Interconnected System in the event of an extended LIL outage. To address the immediate need to back up the LIL on an interim basis, Hydro has recommended extending operations of the Holyrood TGS, potentially through 2030. All three Holyrood TGS units will remain 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 Units 1 and 2 are scheduled to be shut down and decommissioned.

Therefore, for the purposes of this report, it was assumed that the Holyrood TGS is available through the near-term study period (2023–2027).

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.

[33] 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 on peak.
[34] 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 Hydroelectric Generating Facility during the months of January to March and November to December during off-peak hours.

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. 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 the 230 kV transmission line TL209. A project to complete these modifications was included in Hydro's "2021 Capital Budget Application."[35] Following its retirement, Hydro intends to utilize components from the Stephenville Gas Turbine as spares to support the reliable operation of the Hardwoods Gas Turbine.

In light of anticipated load growth and the recent positive performance of the Stephenville Gas Turbine, Hydro will consider the continued operation of the Stephenville Gas Turbine beyond 2024, if deemed necessary, in its analysis for the 2024 update.

With respect to the Hardwoods Gas Turbine, asset availability at these facilities is significantly improved over the levels previously observed.[36] In its 2022 Update, Hydro also 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 scenarios where it is assumed that the LIL is not relied on for capacity through the study period (2023–2027), both the Hardwoods and Stephenville Gas Turbines are assumed to remain in service through the study period.

[35] "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. II, tab 14.
[36] 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.

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[37] and industrial load.[38] 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).

4.2 Economic Setting

Newfoundland and Labrador showed signs of recovery in 2021 and 2022. Consumer spending and capital investment rebounded from 2020 levels, while other economic indicators, such as the labour market and household disposable income, have improved throughout the last two years.

Looking forward through the medium term (i.e., one to five years) several developments will positively influence provincial economic activity, both in Labrador and on the Island. Several major oil projects (i.e., Bay du Nord[39] and West White Rose) should increase investment and contribute to employment gains. In 2018, Greig NL's Placentia Bay aquaculture project was released from environmental assessment; the project is expected to be fully operational by 2025. 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; construction commenced in 2022 and first production is expected in 2024. Vale Newfoundland and Labrador Limited ("Vale") continues to proceed with the development of two underground mines at Voisey's Bay; first production from one of

[37] Residential and general service loads of Newfoundland Power and Hydro.
[38] Hydro currently has five Industrial customers on the Island and two Industrial customers in Labrador.
[39] "Bay du Nord on hold for up to 3 years, CBC News, May 31, 2023, <https://www.cbc.ca/news/canada/newfoundland-labrador/bay-du-nord-on-hold-1.6860387>.

the underground mines occurred in 2021. This project is a large capital investment and a long-term source of nickel concentrate for the Long Harbour Processing Plant.

Over the medium term, adjusted real GDP[40] is forecast to increase with increases in exports being driven by iron ore production and the expected restart of operations at the refinery in Come By Chance. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that lower oil production and lower mineral prices will hinder overall economic growth in the near term; however, non-residential activity, stemming from major projects, will contribute to positive economic growth in the near-term.[41,42]

While the current provincial government's fiscal situation remains relatively challenging, the underlying local market conditions for electric power operations through the medium term in the context of provincial energy requirements suggest modest increases in energy requirements throughout the forecast period, which is partially driven by actions to combat climate change resulting in a shift towards electrification.

4.3 Forecast Load Requirements

The customer load requirement component of Hydro's near-term load forecast remains consistent with that used in Hydro's November 2022 Report. Hydro anticipates updating its forecast load requirements by the end of spring 2023. The revised load forecast is anticipated to be the basis of Hydro's November 2023 update to this report, which will be prepared in advance of the 2023–2024 winter operating season. Hydro's near-term Labrador Interconnected System load forecast continues to reflect the unresolved power supply constraints to the western Labrador system. Hydro anticipates these constraints will be addressed through the ongoing implementation of the *Network Additions Policy – Labrador Interconnected System* ("*Network Additions Policy*").[4344]

[40] Gross domestic product ("GDP").
[41] "Provincial Economic Forecast", TD Economics, June 2022, <https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Jun2022.pdf>.
[42] "Provincial Outlook", RBC, June 2022, <https://royal-bank-of-canada-2124.docs.contently.com/v/provincial-outlook-june-2022-final-pdf>.
[43] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*. <https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf>.
[44] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 4.4 provides for further information on the *Network Additions Policy*.

The demand forecasts by system are provided in Table 3 to Table 5.

Table 3: Island Interconnected System ("IIS") Peak Demand Forecast (MW)[45]

	2023	2024	2025	2026	2027
Utility[46]	1,487	1,516	1,511	1,509	1,512
Industrial Customer	161	168	205	209	209
IIS Customer Coincident Demand	**1,648**	**1,684**	**1,716**	**1,718**	**1,721**
IIS Transmission Losses and Station Service	99	99	99	99	99
Total IIS Demand	**1,747**	**1,783**	**1,815**	**1,817**	**1,820**

Table 4: Labrador Interconnected System ("LIS") Peak Demand Forecast (MW)[47,48]

	2023	2024	2025	2026	2027
Utility	146	147	148	149	150
Industrial Customer	308	308	308	308	308
LIS Customer Coincident Demand	**454**	**455**	**456**	**457**	**458**
LIS Transmission Losses and Station Service	29	29	29	29	29
Total LIS Demand	**483**	**484**	**485**	**486**	**487**

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

	2023	2024	2025	2026	2027
NLIS Coincident Demand	2,074	2,111	2,144	2,148	2,151
NLIS Transmission Losses and Station Service	127	127	127	127	127
Total NLIS Demand	**2,201**	**2,238**	**2,271**	**2,275**	**2,278**

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. In 2022, the limits include a conservative estimate of LIL energy delivered to the Island Interconnected System in consideration of ongoing commissioning activities through 2022 and the unlikely event that the LIL is unable to deliver energy to the Island

[45] Numbers may not add due to rounding.
[46] The utility demand forecast includes approximately 22 MW of potential interruptible load in 2024 and 49 MW of potential interruptible load post 2024.
[47] Numbers may not add due to rounding.
[48] Hydro has included its obligation under the current temporary service agreement with Blockchain Labrador Corporation in its forecast while the non-firm rates proceeding is ongoing as per Public Utilities Act, RSNL 1990, c P-47, Board Order No. P.U. 36(2022), Board of Commissioners of Public Utilities, December 16, 2022.

Interconnected System for three months during winter 2023.[49] The analysis assumed that only one unit at the Holyrood TGS would be online at full capability while the LIL is delivering energy to the Island and that the other two units would be available but not online until the hypothetical three-month LIL outage starting in January 2023. The methodology was updated in this way to acknowledge the financial benefits of supporting island system storage with energy from the Muskrat Falls Hydroelectric Generating Facility instead of thermal energy from the Holyrood TGS. The two Holyrood TGS units that are available but not online are viewed as a reliability measure for a LIL outage event but not as a preferred source of energy while the LIL is available.

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. The minimum storage limits are established to the end of April 2023. The remaining 2023 limits will be established following the freshet.

A snow survey was conducted from April 3 to 6, 2023, which found that the overall remaining snowpack across Hydro's major Island reservoirs was approximately 92% of the historical average for April. Snowpack varied considerably across the Island reservoirs with some areas in the Bay d'Espoir System, such as Long Pond and Upper Salmon having insufficient remaining snow to survey. Many other areas of the Bay d'Espoir System also had a below-average snowpack. Meelpaeg Reservoir snowpack was found to be 84% of average while Granite Reservoir and Burnt Pond were 65% and 68%, respectively. Victoria Reservoir snowpack exceeded the April average, however, and was 144% of the average. Hinds Lake snowpack was found to be 99% of the average while Cat Arm snowpack was 134% of the historical average.

At this time, Hydro does not foresee using production from standby generation to support reservoir levels. 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.

[49] The three winter months are January to March 2023, inclusive.

At the end of April 30, 2023, the total system energy in storage was 1,551 GWh, 1,331 GWh above the minimum storage limit of 220 GWh for April 2023. Chart 1 plots the 2022 and 2023 storage levels, maximum operating level storage, and the 20-year average aggregate storage for comparison.

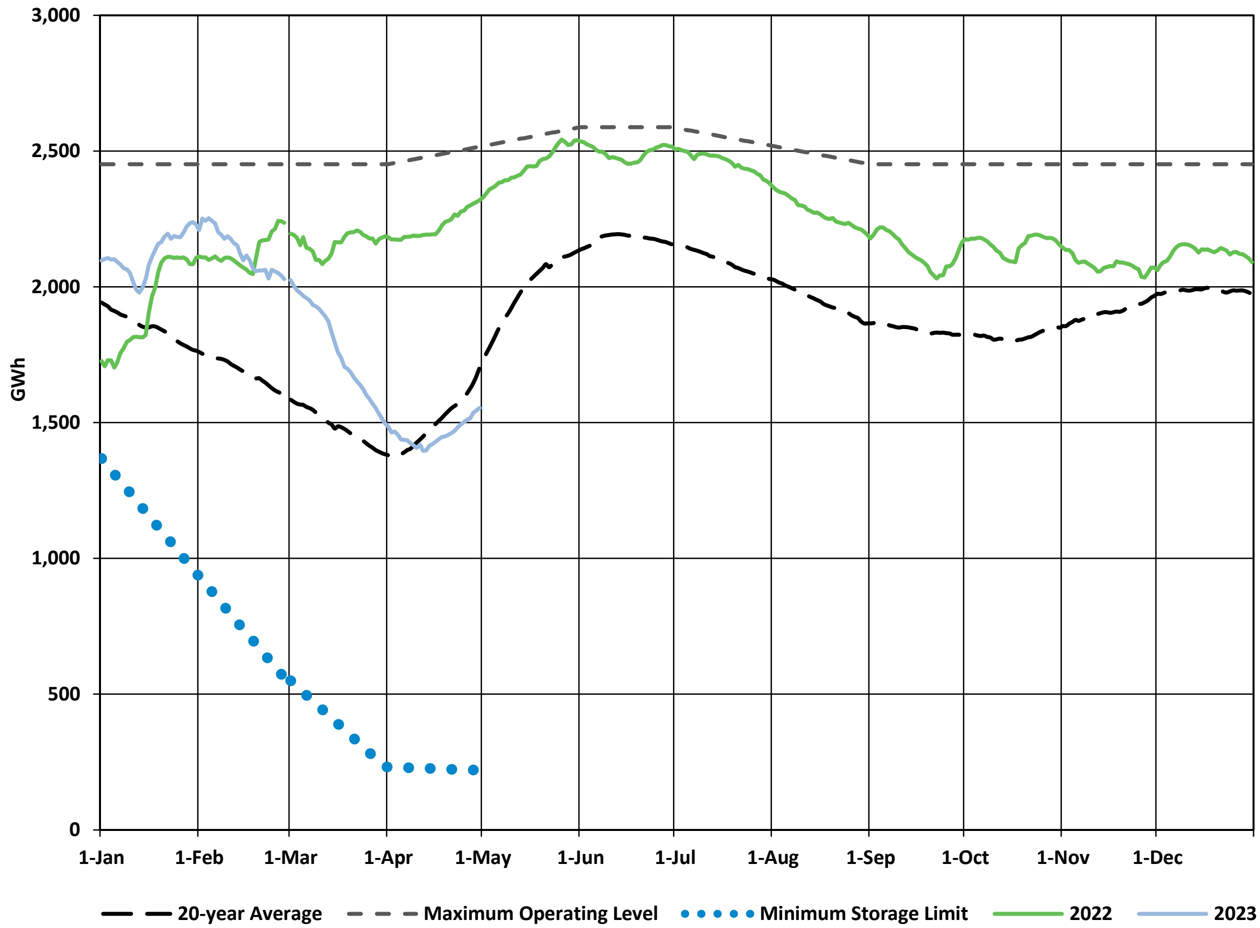

Chart 1: Total Energy Storage for April 30, 2023

6.0 Availability of Imports

In previous near-term filings, 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. Since the availability of these contracts requires a counterparty to provide firm capacity, it has been previously stated that there is no guarantee that these contracts will be available and the intent of the analysis was to demonstrate the effect on the system if the capacity was available in the requested amounts.

When considering the long-term 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[50]

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 limited 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.

    - The interface between the New Brunswick/Nova Scotia transmission systems is often congested. In a January 2022 integrated resource plan update from Nova Scotia Power, it discussed firm imports on this interface

        > Discussions with NB Power[51] have identified that firm transmission capacity over the existing NS[52]/NB[53] interface continues to be unavailable in significant quantities at the present time; NS Power[54] will continue to pursue technical solutions in collaboration with NB Power.[55]

[50] Refer to Hydro's response to NP-NLH-093 of this proceeding.
[51] New Brunswick Power Corporation ("NB Power").
[52] Nova Scotia ("NS").
[53] New Brunswick ("NB").
[54] Nova Scotia Power Inc. ("NS Power").
[55] "Integrated Resource Plan Action Plan Update," Nova Scotia Power Inc., January 2022, <https://irp.nspower.ca/files/key-documents/action-plan-updates/IRP-Action-Plan-Update-April-2022.pdf>.

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 interprovincial transmission constraints in delivering imported energy via the Maritime Link to the Avalon Peninsula. The Off-Avalon-to-On-Avalon transmission constraints are being reviewed in 2023 and will be discussed further in the next Reliability and Resource Adequacy Study update.

6.2 Firm Energy Availability[56]

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

- **Nova Scotia**: According to their 2022 ten-year system plan, Nova Scotia Power does not have surplus capacity in their system to export. Nova Scotia Power heavily relies on coal to meet their capacity requirements in the winter and they are looking to replace their coal plants (approximately 1,050 MW) by 2030 to meet federal government regulations.
- **New Brunswick**: NB Power filed a ten-year Integrated Resource Plan in 2020,[57] at which time they did not have any significant surplus capacity. 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.

[56] Refer to Hydro’s response to NP-NLH-093 of this proceeding.
[57] “2020 Integrated Resource Plan,” New Brunswick Power Corporation, November 17, 2020, < https://www.nbpower.com/media/1490323/2020-irp-en-2020-11-17.pdf>.

In April 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 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).

7.1 Scenario Analysis

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

- **Scenario 1:** Assumes that the LIL will be available at 700 MW for the study period with a 10% bipole forced outage rate until January 2024 and a 5% bipole forced outage rate thereafter. This case assumes a DAUFOP of 20% for the Holyrood TGS as well as the retirement of Stephenville Gas Turbine on March 31, 2024.
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS forced outage rate to the 2021 actual of 34%.
    - **Scenario 2A:** Varies from Scenario 2 by keeping the Stephenville Gas Turbine in service through the study period
- **Scenario 3**: Varies from Scenario 1 by maintaining a 10% bipole forced outage rate through the study period.
- **Scenario 4**: Varies from Scenario 1 by decreasing the bipole forced outage rate to 1% in January 2024 for the remainder of the study period.
- **Scenario 5:** Varies from Scenario 1 by considering the LIL to be an energy-only line through the study period (2023–2027) (i.e., the LIL provides no reliability benefits). The operation of Stephenville Gas Turbine is extended through the study period at baseline forced outage rate, as the operation of the Holyrood TGS and the Hardwoods Gas Turbine are already assumed available through the study period.

- **Scenario 6:** Varies from Scenario 1 by increasing the Holyrood TGS forced outage rate to the 2021 actual of 34% and maintaining a 10% bipole forced outage rate through the study period.
    - **Scenario 6A:** Varies from Scenario 6 by keeping the Stephenville Gas Turbine in service through the study period.

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 in the possible event of a LIL bipole outage, these existing units could provide capacity assistance.

For CBPP Capacity Assistance, the existing agreement expired on March 31, 2023. Hydro is currently in discussions with CBPP regarding an agreement for next winter. In all scenarios, it is assumed that the CBPP Capacity Assistance remains in place throughout the study period, beyond the expiry of the current contract. Since the winter of 2014–2015, CBPP has been willing to enter into mutually-beneficial capacity assistance arrangements with Hydro. It is assumed that similar arrangements will continue.

7.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 7.2.1 and 7.2.2 provide the results of the annual and monthly analyses, respectively.

7.2.1 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. 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 Reliability and Resource Adequacy Study update, as Hydro continues to gather information while working with stakeholders.

Table 6: Annual LOL, EUE, and NEUE Results

LOLH (hours)	2023[58]	2024	2025	2026	2027
Scenario 1: LIL at 700 MW, LIL Bipole FOR[59] = 5%, Holyrood TGS DAUFOP = 20%	0.2	0.7	0.9	0.9	0.9
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	0.6	1.9	2.6	2.5	2.5
Scenario 2A: SVL GT[60] in Service to the End of the Study Period	0.5	1.8	1.9	1.8	1.8
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	0.2	1.3	1.8	1.8	1.8
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.2	0.1	0.2	0.2	0.2
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	1.8	12.2	12.8	12.5	12.9
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	0.6	3.7	5.2	4.9	4.9
Scenario 6A: SVL GT in Service to the End of the Study Period	0.6	3.5	3.8	3.6	3.7

EUE (MWh)	2023[61]	2024	2025	2026	2027
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	11	43	62	60	62
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	39	138	198	193	196
Scenario 2A: SVL GT in Service to the End of the Study Period	37	128	139	135	135
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	10	86	122	123	125
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	11	9	13	12	12
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	110	807	842	829	859
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	39	275	397	381	385
Scenario 6A: SVL GT in Service to the End of the Study Period	39	259	276	265	271

NEUE (ppm)[62]	2023	2024	2025	2026	2027
Scenario 1: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	6	4	5	5	5
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	20	12	17	17	17
Scenario 2A: SVL GT in Service to the End of the Study Period	19	11	12	12	12
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	6	7	11	11	11
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	6	1	1	1	1
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	59	70	72	71	74
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	20	24	34	33	33
Scenario 6A: SVL GT in Service to the End of the Study Period	20	23	24	23	23

[58] Results for 2023 are for the remainder of the year (June 1 through December 31).
[59] Forced outage rate ("FOR").
[60] Stephenville Gas Turbine ("SVL GT").
[61] Results for 2023 are for the remainder of the year (June 1 through December 31).
[62] 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 1–4 indicate that the availability of the LIL at partial capability, under various LIL bipole forced outage rates, and backed up by the Holyrood TGS and the Hardwoods Gas Turbine, mitigates the risk of lost load and unserved energy in the near term in almost all years except 2023 in Scenario 2. The results of Scenario 2 indicate that there is a risk to system reliability in 2023 only at the higher Holyrood TGS DAFOR value observed in 2021, combined with the increased LIL forced outage rate assumption of 10% in 2023. The risk to system reliability decreases in 2024 in Scenario 2 when the LIL bipole forced outage rate decreases from 10% to 5%. As such, it can be observed that there is an increased risk of generation shortfall until the LIL is reliably in service, with the amount of risk 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 Gas Turbine as a reliable generation stations in the near term.

Scenario 5 indicates that if the LIL reliability is such that it is not counted upon for capacity (i.e., considered an energy-only line), there is a material 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 November 2022 Report. With that said, progress has been made with integrating the Muskrat Falls Project Assets into the Island Interconnected System, with the LIL currently tested to 700 MW. It is expected that the LIL will be available in some capacity through the winter period; however, operational experience is needed to better understand LIL reliability.

The results of Scenario 6 demonstrate that if the LIL has a forced outage rate of 10% through the study period concurrent with a high degree of unavailability at the Holyrood TGS, there is a considerable amount of system risk present. Extending the service life of the Stephenville Gas Turbine would reduce, but not eliminate, this risk.

7.2.2 Monthly Assessment Results

Table 7 to Table 11 provides 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 analyses allow 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.

In Scenarios 1–4, the availability of the LIL at partial capability, backed up by the Holyrood TGS and the Hardwoods Gas Turbine through the study period and the Stephenville Gas Turbine until March 31, 2024, largely mitigates the risk of lost load and unserved energy. As expected, the results of Scenarios 2 and 3 indicate that both LOLH and EUE grow as the unavailability of the Holyrood TGS and/or the LIL increases.

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 do not meet reliability criteria in the winter months. In addition, Scenario 6 indicates that if both the LIL and Holyrood TGS are experiencing poor performance, reliability is not met during the winter period. The retention of the Stephenville Gas Turbine as a generation unit could help mitigate the increased risk of resource shortfalls if the LIL reliability is worse than what is assumed as the base case in this analysis, or if the Holyrood TGS or other generating assets were to perform more poorly than the assumptions outlined in this analysis. With that said, it is unlikely that the LIL will not be available in any capacity throughout the entire study period (2023–2027). In Volume III of the 2022 Update, Hydro addressed the loss of the LIL for up to six weeks in the winter period. In that scenario, both the Holyrood TGS and Hardwoods Gas Turbine were sufficient to reduce rotating outages to approximately 100 MW at peak during the most severe conditions in the winter.[63] In the average case, almost all shortfall was covered by the extension of Holyrood TGS and Hardwoods Gas Turbine.[64]

[63] While it is important to understand the implications of a six-week LIL shortfall as well as what is required to reduce/mitigate rotating outages for system planning purposes, it is not assessed against reliability metrics. “Reliability and Resource Adequacy Study – 2022 Update,” Newfoundland and Labrador Hydro, October 3, 2022, vol. I provides the generation requirements to meet long-term reserve planning criteria.
[64] If projected load growth is higher than currently forecast, the projected shortfall will also increase.

Table 7: Monthly LOLH and EUE for 2023[65]

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%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Scenario 2A: SVL GT in Service to the End of the Study Period	N/A	N/A	N/A	N/A	N/A	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%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	1.7
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 6A: SVL GT in Service to the End of the Study Period	N/A	N/A	N/A	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.5

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%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	11
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	38
Scenario 2A: SVL GT in Service to the End of the Study Period	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	37
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	10
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	10
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	1	107
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	38
Scenario 6A: SVL GT in Service to the End of the Study Period	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	38

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

Table 8: Monthly LOLH and EUE for 2024

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%	0.3	0.1	0.1	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%	0.9	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 2A: SVL GT in Service to the End of the Study Period	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 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	0.7	0.2	0.1	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%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	6.7	2.3	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.8
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	1.7	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Scenario 6A: SVL GT in Service to the End of the Study Period	1.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5

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%	23	7	4	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	71	26	12	1	1	0	0	0	0	0	1	26
Scenario 2A: SVL GT in Service to the End of the Study Period	70	25	14	1	0	0	0	0	0	0	1	17
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	47	14	7	1	0	0	0	0	0	0	1	16
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	5	2	1	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	478	140	69	3	1	1	0	0	0	0	3	112
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	143	48	26	2	1	1	0	0	0	0	2	52
Scenario 6A: SVL GT in Service to the End of the Study Period	144	49	27	1	1	0	0	0	0	0	1	36

Table 9: Monthly LOLH and EUE for 2025

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%	0.4	0.2	0.1	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%	1.2	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 2A: SVL GT in Service to the End of the Study Period	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 3: LIL at 700 MW, LIL Bipole FOR = 10%, 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 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	6.6	2.7	1.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.0
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	2.3	1.2	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8
Scenario 6A: SVL GT in Service to the End of the Study Period	1.7	0.9	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6

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%	34	13	6	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	101	40	21	1	1	0	0	0	0	0	1	32
Scenario 2A: SVL GT in Service to the End of the Study Period	74	28	14	1	0	0	0	0	0	0	1	21
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	67	25	11	1	0	0	0	0	0	0	1	18
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	8	3	1	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	467	170	73	3	2	1	0	0	1	0	3	123
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	199	90	43	2	1	1	0	0	0	0	2	59
Scenario 6A: SVL GT in Service to the End of the Study Period	141	60	29	1	1	0	0	0	0	0	1	42

Table 10: Monthly LOLH and EUE for 2026

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%	0.4	0.2	0.1	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%	1.1	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 2A: SVL GT in Service to the End of the Study Period	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 3: LIL at 700 MW, LIL Bipole FOR = 10%, 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 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.1	0.0	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%	6.6	2.6	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	2.2	1.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Scenario 6A: SVL GT in Service to the End of the Study Period	1.8	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6

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%	33	11	6	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	98	41	22	1	0	0	0	0	0	0	0	30
Scenario 2A: SVL GT in Service to the End of the Study Period	71	29	13	0	0	0	0	0	0	0	0	20
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	69	24	11	1	0	0	0	0	0	0	0	19
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	7	2	1	0	0	0	0	0	0	0	0	1
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	479	155	69	2	1	1	1	0	1	1	1	119
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	198	78	41	2	1	1	0	0	0	1	0	60
Scenario 6A: SVL GT in Service to the End of the Study Period	143	54	26	1	0	0	0	0	0	0	0	39

Table 11: Monthly LOLH and EUE for 2027

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%	0.5	0.2	0.1	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%	1.2	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 2A: SVL GT in Service to the End of the Study Period	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 3: LIL at 700 MW, LIL Bipole FOR = 10%, 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 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	0.1	0.0	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%	6.9	2.5	1.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	2.3	1.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Scenario 6A: SVL GT in Service to the End of the Study Period	1.8	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6

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%	36	12	6	0	0	0	0	0	0	0	0	8
Scenario 2: LIL at 700 MW, LIL Bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	102	41	21	1	0	0	0	0	0	0	0	30
Scenario 2A: SVL GT in Service to the End of the Study Period	71	27	14	0	0	0	0	0	0	0	0	22
Scenario 3: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	72	23	12	0	0	0	0	0	0	0	0	17
Scenario 4: LIL at 700 MW, LIL Bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	7	2	1	0	0	0	0	0	0	0	0	2
Scenario 5: LIL as Energy-Only Line, Holyrood TGS DAUFOP = 20%	500	158	73	2	1	1	1	0	1	1	1	119
Scenario 6: LIL at 700 MW, LIL Bipole FOR = 10%, Holyrood TGS DAUFOP = 34%	204	78	40	2	1	0	0	0	0	1	1	58
Scenario 6A: SVL GT in Service to the End of the Study Period	146	55	27	1	1	0	0	0	0	0	0	40

8.0 Conclusion

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. As previously identified by both Hydro and The Liberty Consulting Group, the availability of power over the LIL remains essential to system reliability.

To help ensure reliable service for customers in the near term, Hydro has committed to maintaining the Holyrood TGS and the Hardwoods Gas Turbine as generating facilities until new generation can be integrated to the system, possibly through to 2030, in addition to maintaining the Stephenville Gas Turbine until its planned retirement by March 31, 2024. In light of anticipated load growth and recent performance of the Stephenville Gas Turbine, Hydro will consider the possibility of continued operation of the Stephenville Gas Turbine beyond 2024, if deemed necessary, in its analysis for the 2024 update.

In this analysis, Hydro has also presented results of system reliability metrics considering the assets:

- In service as planned;
- In service at levels that have already been demonstrated, and;
- Not in service, to ensure that it has a fulsome understanding of the resultant system reliability considering the full range of operating scenarios for the Muskrat Falls Project Assets.

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. Hydro is also focused on the completion of its annual maintenance program to ensure the reliability of its existing assets and infrastructure in the near term.