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, 2022

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

Dear Ms. Blundon:

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

Further to the Board of Commissioners of Public Utilities' correspondence of October 13, 2016, requesting semi-annual reports on May 15 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

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

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
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 & Wadden
Stephen F. Fitzgerald, Browne Fitzgerald Morgan Avis & Wadden
Sarah G. Fitzgerald, Browne Fitzgerald Morgan Avis & Wadden
Bernice Bailey, Browne Fitzgerald Morgan Avis & Wadden
Bernard M. Coffey, KC

Reliability and Resource Adequacy Study 2022 Update

Volume II: Near-Term Reliability Report – November Report

November 15, 2022

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

Supply adequacy in the early operation of the Muskrat Falls Project Assets 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 mitigating measures to ensure customer requirements are met during this period.

This report discusses the 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] that 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").

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 by using an annual analysis only. As LOLH and EUE do not currently have generally acceptable criteria, unlike the generally accepted Loss of 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.

[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").

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 May 2022 Near-Term Reliability Report ("May 2022 Report"),[3] the Labrador-Island Link ("LIL") has been successfully tested and operated to 475 MW.

As has been observed in prior near-term reports, 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 2022–2023 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 will not be available for the reporting period 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").[4]

Finally, Hydro has also included assessments of the increased level of reliability resulting from supplementing Island supply with imports over the Maritime Link.

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," filed in November 2018 ("2018 Filing"),[5] with updates to reflect current system assumptions.[6]

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[7] website.

[3] "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 16, 2022.
[4] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[5] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[6] Volumes I and II of the 2018 Filing 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 Volume I of the 2022 Update.
[7] Open Access Same-Time Information System ("OASIS").

3.0 Asset Reliability

Reports are filed with the Board on a quarterly basis that include actual forced outage rates and their relation to:

- The rolling 12-month performance of its units;[8]
- 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 October 31, 2022.[9]

Hydro continues to take action to address repeat performance issues by conducting broader reviews that frequently involve external experts, addressing issues with urgency, and placing an increased focus on asset reliability.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since filing its May 2022 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 significantly impact unit reliability if not appropriately managed. The information in Sections 3.1.1 through 3.1.3 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 sections that follow describe issues, both asset and condition based, that have previously affected generating unit reliability, as well as the current 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

[8] Quarterly Report on Performance of Generating Units.
[9] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended September 30, 2022," Newfoundland and Labrador Hydro, October 31, 2022.

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 penstocks, and Upper Salmon Hydroelectric Generating Station rotor rim key cracking and rotor rim guidance block defects; and
  - Ongoing Issues: Granite Canal Control System.
- Thermal Facilities:
  - Continued Monitoring: Boiler feed pump motor issues, variable frequency drives ("VFD"), and T2 power transformer failure;
  - Ongoing Issues: Unit boiler tubes; and
  - Resolved Issues: Power Centre C failure.
- Gas Turbines:
  - New Issue: Stephenville Gas Turbine ("Stephenville GT") 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

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.[10] In response to the most recent September 2019 failure of Penstock 1, 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

[10] "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.

review results were filed with the Board on June 3, 2020.[11] As outlined in that correspondence, Hydro has pursued and concluded Stage 2, front-end engineering design ("FEED"). Kleinschmidt was engaged to perform all functions of the FEED, which was completed by the end of the third quarter of 2022. The FEED results include an investment strategy plan for life extension activities related to all three Bay d'Espoir penstocks.

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, once dispatched, Units 1 and 2 are limited to a minimum unit loading of 50 MW and are not cycled or shut down as part of normal system operations.

The 2022 inspection for Penstock 1 was completed on April 28, 2022. During the inspection, two weld indications were discovered in previously repaired areas of the penstock. These indications were assessed and repairs were deemed necessary to complete repairs to ensure continued reliable operation. Repairs were completed and the penstock was returned to service on May 2, 2022. Penstock 2 was inspected in October 2022 and Penstock 3 in July 2022; both inspections revealed no material concerns. Hydro will use the information obtained through the inspection and refurbishment process to inform its long-term plan for the penstocks; the details of which are expected to be filed with the Board in 2022.

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. Hydro has estimated a 13- to 23-day repair timeline, depending on circumstances, should a new failure occur.

Upper Salmon Rotor Key Cracking and Rotor Rim Guidance Block Defects

As previously reported, in 2018, the rotor rim keys on the Upper Salmon generating unit were replaced during the unit's annual maintenance outage. As per consultation with the original equipment

[11] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

manufacturer ("OEM"), Hydro has continued to schedule and conduct regular inspections of the new rotor rim keys at Upper Salmon throughout the anticipated wear-in period to assess the effectiveness of the replacement keys. After the 2019 reseating of the keys, inspections were scheduled every four weeks; this was extended to six weeks in 2020 after successive inspections found no signs of cracking. Superficial cracks were identified and resolved during the August 2020 inspection; however, inspections completed between August 2020 and the annual maintenance outage in August 2021 revealed no new cracking.

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 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.

The OEM considers contributing factors to this issue to be a combination of an out-of-round stator and a loose rotor rim. While addressing this life extension work was not possible prior to the 2021–2022 winter season, the replacement of the blocks was considered a suitable approach by the OEM to reduce the residual risk to an acceptable level for operation in the coming winter operating season. In addition to the block replacement, the OEM has recommended implementing a NDT inspection program of the blocks at 12-week intervals (approximately 2,000 hours of continuous run time) until the life extension work scope is completed. Hydro now includes this inspection program in its maintenance activities.

Subsequent NDT inspections, completed in November 2021, February 2022, May 2022, July 2022, and October 2022, revealed no material concerns with newly installed blocks; however, cracks and fretting corrosion were found on rim keys, as have been previously seen. Following further consultation with the OEM, it was advised to continue with the more frequent inspections every 1,000 hours (approximately six weeks of continuous run time). The Board approved an application by Hydro to undertake additional work to address the required life extension activities.[12] Engineering and procurement for this work has since commenced, with field execution activities scheduled for 2023.

Although Hydro has mitigated the risk of failure to the extent possible in the near term, there is a residual risk that a failure could occur before the execution of the required life extension work scope. To offset the impact of an unplanned outage, Hydro is advancing procurement of long lead time materials that would address the underlying contributing factors, the details of which are outlined in the supplemental capital budget application.

Granite Canal Control System

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 unit at the Granite Canal Hydroelectric Generating 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 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 will require replacement. This replacement is now reflected in the long-term plan and required capital work will be proposed as part of the capital budget process in an appropriate future year; however, FEED has commenced ensuring that the capital project is appropriately scoped and budgeted. 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.

3.1.2 Thermal

Boiler Feed Pump Motors

On October 25, 2020, Hydro experienced a failure of the Holyrood TGS Unit 1 boiler feed pump west. Unit 1 was offline on a forced outage until November 7, 2020; the unit remained derated to 50% load until

[12] "Application for Approval for Rotor Rim Shrinking and Stator Recentering at the Upper Salmon Hydroelectric Generating Station," Newfoundland and Labrador Hydro, April 26, 2022, 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.

November 16, 2020, when the pump was returned to service. Following the failure, which forced Unit 1 offline and to remain derated for a period of time once returned to service, a TapRooT investigation determined the root cause of the pump failure was a miscommunication that led to the suction valve being closed on the operating pump in error. The investigation also identified some safeguards that were not in place that could have mitigated the failure, including modifications to the control logic that had not been set up to trip the feed pump when the suction valve was moved from the open position, as well as motor protection settings, and preventive maintenance practices.

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 complete or planned for completion. Preventive maintenance strategies have been modified to include a mechanical assessment of critical components of 4,160 V motors. Interlocking logic is being reviewed for all 4,160 V motors at the Holyrood TGS. The settings for all boiler feed pump motors have been updated as planned. The settings for the Unit 2 and Unit 3 forced draft fan motors have also been updated with the remaining scheduled for completion during the 2023 annual outages.

Hydro will provide the updated status of these actions in the May 2023 update of this report.

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 need. 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 prior to 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 will be returned to service without VFDs on the forced draft fans. Conversion of Unit 1 was not possible in 2022 due to shop resource loading and outage schedules. Hydro plans to bypass the VFDs on Unit 1 in 2023, as the unit experienced VFD power cell failures when returned to service this fall. Hydro will provide an update of the VFDs in the May 2023 update of this report.

T2 Power Transformer Failure – Unit 2

The Unit 2 power transformer, T2 failed on November 12, 2021. The failed transformer was replaced with the onsite spare. The unit was returned to service for 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. Due to the specifications of the spare transformer that was installed, the full load capability of Unit 2 with the replaced power transformer was 150 MW for the 2021–2022 operating season. During the 2022 annual Unit 2 outage, a pump was replaced inside the transformer that allows for an increase of the output of this unit. As a result, Unit 2 is expected to have a rating of 170 MW in advance of the 2022–2023 operating season. The ability to reach 170 MW will be confirmed through testing that will be conducted later in 2022 when Unit 2 is returned to service and when the power grid allows testing at a high load. Investigation into the cause of the transformer failure remains ongoing. Hydro has engaged outside technical support through both Hitachi Energy (ABB) and Doble Engineering to assist with this investigation. Hydro will provide an update on the operational capability of Unit 2 and the status of the failure investigation in the May 2023 update of this report.

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 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, which was executed during the 2022 annual outage season. Hydro has determined that boiler tube sections, as a whole, are in good condition, however, tube failures continue to pose a risk. Hydro maintains a thorough selection of spare tube material and a contract with an experienced boiler contractor for the provision of emergency repairs in the event of tube failures.

Power Centre C Failure

Following a unit trip caused by Power Centre C, a 600 V load centre going offline, a TapRooT investigation determined the root cause leading to the Unit 1 trip and load limitation on Unit 2 was determined to be that the breaker which protects compressor #1 had its instantaneous overcurrent element (50G) disabled. This caused a chain of events that resulted in the trip of Power Centre C, the trip of Unit 1, and the temporary inability to increase load on Unit 2.[13] The corrective action to enable the 50G element in the compressors' breakers was completed as part of the annual maintenance program in 2021. This will prevent recurrence of this failure.

Other follow-up actions were identified in the investigation. A review of the loads connected to each power centre was completed in 2021 for all power centres to determine if power centre unavailability would cause a trip or derate of operating units. The review found no concerns other than the two air compressors fed from Power Centre C. In addition, a fusing review was conducted in 2022, with work completed during the planned annual outages. This study confirmed that the installed fuses are not oversized, and there are no fuse changes recommended.

Hydro considers this issue to be resolved.

3.1.3 Gas Turbines

Stephenville Gas Turbine – Alternator Glycol Pump Failure

On September 27, 2022, the Stephenville GT 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. Some small cracks were identified via a NDT analysis and

[13] For additional detail on the outage itself and the outcomes of Hydro's TapRooT investigation, please refer to Hydro's "Reliability and Resource Adequacy Study – 2021 Update – Volume II: Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2021.

repaired in piping connections near the failed pump. However, dirt and debris were found throughout the piping system including in the cooling water supply lines to the pumps bearing cavity and is considered the root cause of the pump failure. Due to the design of the cooling system, the debris has likely been in the system since its installation in 2013. To ensure the system was clean, it was flushed several times until no additional debris remained in the system. The unit was returned to service on October 17, 2022, once the alternator cooling system was repaired and refilled. The damaged glycol pump is expected to be repaired and reinstalled prior to winter 2022–2023. Hydro will provide an update in the May 2023 update of this report.

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.[14] Assumptions on forced outage rates of generating units are updated annually in accordance with Hydro's forced outage rates methodology.[15]

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

[14] Forced outage rate refers to an input to the reliability model, which represents the percentage of hours in a year when a unit is unavailable.
[15] In this report, Hydro deviated from the forced outage rate methodology as outlined in the 2019 Update when selecting forced outage rates for its hydroelectric units and for the Holyrood Gas Turbine ("Holyrood GT"). 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 maintained the capacity-weight average DAFOR from the November Report, which is higher than the 5-year DAFOR, increasing the forced outage rate to more appropriately represent the risk of failure in the near term. For the Holyrood GT, Hydro used a scenario-based approach to estimate the forced outage rate.

operated as a synchronous condenser during the summer months and shoulder periods.[16,17] 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.[18] 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 the Canadian Electricity Association (“CEA”) 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.

[16] 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.
[17] Unit 3 requires 24 to 36 working hours to convert from synchronous condense mode to generate mode.
[18] Refer to “Reliability and Resource Adequacy Study – 2022 Update,” Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.3.1.

Table 1: Forced Outage Rates for Hydro-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 2.3%
Holyrood Thermal Units – Base Assumption	DAUFOP = 20%
Holyrood Thermal Units – Sensitivity Assumption	DAUFOP = 34%
Holyrood GT	DAUFOP = 4.9%
Happy-Valley GT[19]	DAUFOP = 6.7%
Stephenville GT	DAUFOP = 30%
Hardwoods GT[20]	DAUFOP = 30%
Diesels	DAUFOP = 7.9%

In previous near-term filings, once modelled as in service, the LIL's availability was modelled with a declining monopole forced outage rate (i.e., improving performance) to capture any testing activities and potential operational unknowns during the first years of operation.[21] As noted in the 2022 Update,[22] 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. The monopole forced outage rate is not a driver for LIL reliability, given the ability for each pole to be loaded to 1.5 times its rated capacity on a continuous basis (675 MW).

Until the LIL is fully commissioned with multiple years of operational experience to better inform the selection of a bipole forced outage rate, the LIL capacity and bipole forced outage rate will be addressed with a range of upper and lower limits. As LIL performance statistics become available in the coming years, the forced outage rate range can be narrowed in future filings. A similar approach was taken with the LIL capacities. As the LIL is not yet fully commissioned to its rated 900 MW capacity but has currently been tested up to 475 MW, a range of capacities was also considered.

For the purpose of this analysis, the LIL is assumed to be available at a reduced capacity of 475 MW through 2023 with a 10% bipole forced outage rate, and at 675 MW with a 5% bipole forced outage rate

[19] Happy-Valley Gas Turbine ("Happy-Valley GT").
[20] Hardwoods Gas Turbine ("Hardwoods GT").
[21] In 2021, the monopole forced outage rate was assumed to be 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.
[22] Refer to "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. I, sec. 4.2.1.

thereafter, supported by the full availability of the Muskrat Falls generating units. Consistent with the 2022 Update, bipole forced outage rate sensitivities are included as additional scenarios in the analysis.

Delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery taking place on August 17, 2021.[23] Delivery of Supplemental Energy[24] commenced in November, with the first physical delivery taking place on November 1, 2021, and ceased on April 1, 2022. 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. In instances where the LIL is partially available, the Nova Scotia Block and Supplemental Energy are delivered on a *pro-rata* basis.

For units not owned by Hydro, the forced outage rates used in modelling are determined using industry averages provided in the CEA 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	Reliability Metric
Hydraulic Units	DAFOR = 2.3%
Gas Turbines[25]	DAUFOP = 5.3%
Corner Brook Cogen	DAUFOP = 20.1%

Hydro has confirmed with Newfoundland Power Inc. ("Newfoundland Power") that their corporate plan includes retirements of both their Greenhill and Wesleyville Gas Turbines, as they are nearing the end of their service lives. The intent is 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 GTs) to ensure Hydro is not over-relying on these units.

[23] 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.
[24] 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 Generating Station during the months of January to March and November to December during off-peak hours.
[25] 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%.

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

Import scenarios are contemplated as sensitivities to cases considered in this report; that is, firm imports of 50 MW, 100 MW, and 150 MW from December to March in winters where the LIL is assumed to be 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, there is no guarantee that these contracts will be available. The analysis demonstrates the effect on the system if the capacity was available in the requested amounts.

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.

Subsequent to the May 2022 Report,[26] 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 backup the LIL on an interim basis, Hydro recommends 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 study period (2023–2027).

3.3.2 Hardwoods and Stephenville Gas Turbines

The Stephenville GT consists of two 25 MW gas generators commissioned in 1975. The Hardwoods GT consists of two 25 MW gas generators commissioned in 1976. Each plant provides 50 MW of firm

[26] "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 16, 2022.

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.

Subsequent to the May 2022 Report, the 2022 Update supports the retirement of the Stephenville GT by March 31, 2024, at which point the backup supply for the area served by the Stephenville GT will have been 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.[27] Once the reconfiguration portion of the capital project is complete, the Stephenville GT will no longer be able to support the system as a generating unit. Following its retirement, Hydro intends to decommission the Stephenville GT and utilize its components as spares to support the reliable operation of the Hardwoods GT.

With respect to the Hardwoods GT, operating hours and generation at this facility have decreased materially from levels observed in 2014 through 2018, and asset availability at these facilities is much improved over levels previously observed.[28] The 2022 Update also recommends that the Hardwoods GT 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 GT 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.

[27] "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. II, tab 14.
[28] This reduction in the requirement to operate is primarily attributed to the availability of 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.

In scenarios where it is assumed that the LIL will not be available through the study period (2023–2027), both the Hardwoods GT and Stephenville GT are assumed to remain in service through the study period.

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[29] and industrial load.[30] 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

Newfoundland and Labrador showed signs of recovery in 2021. Consumer spending and the real estate market surpassed pre-pandemic levels, while other economic indicators, such as the labour market and household disposable income, improved throughout the year.

Significant increases in the prices of iron ore, copper, and nickel, along with increased production, resulted in a 36.4% increase in the value of mineral shipments from Newfoundland and Labrador in 2021 compared to 2020. The value of oil production also increased in by 43.2% due to significantly higher oil prices. The seafood sector remained a significant contributor to the provincial rural economy, with the value of fish landings reaching a record high in 2021.

Looking forward through the medium term (i.e., one to five years) there are several developments that will positively influence provincial economic activity, both in Labrador and on the Island. Several major oil projects (i.e., Bay du Nord and West White Rose) should increase investment and contribute to

[29] Residential and general service loads of Newfoundland Power and Hydro.
[30] Hydro currently has five Industrial customers on the Island and two Industrial customers in Labrador.

employment gains. In 2018, Greig NL's Placentia Bay aquaculture project was released from environmental assessment, and 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, with construction scheduled to commence in 2022 and first production expected in 2024. Vale continues to proceed with the development of two underground mines at Voisey's Bay, with first production from one of the underground mines having 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[31] 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 2022 but non-residential activity in the near term, stemming from major projects, will contribute to positive economic growth.[32,33]

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.

[31] Gross domestic product ("GDP").
[32] "Provincial Economic Forecast", TD Economics, June 2022, <https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Jun2022.pdf>.
[33] "Provincial Outlook", RBC, June 2022, <https://royal-bank-of-canada-2124.docs.contently.com/v/provincial-outlook-june-2022-final-pdf>.

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.[34,35] 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 filing of the May 2022 Report include a minor change in forecast Island Interconnected System power and energy requirements across the medium term. Forecast Island Interconnected System peak demand requirement changes in the short term are approximately 0.8% higher than previously forecast and 3.3% higher through the medium term, with forecast energy requirements slightly higher (1.3%) through the medium term. Forecast power and energy requirements for the Island Interconnected System are higher than previously forecast primarily, as a result of an increase in the expectation of power requirements at Memorial University of Newfoundland and Vale.

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 implementation of the Network Additions Policy.[36]

Labrador Interconnected System forecast demand requirement is increased in 2023 compared to the May 2022 filing, reflecting the assumption that Hydro will continue to serve an existing customer following the expiry of their contract in 2022, provided the work related to the Network Additions Policy is still ongoing.[37,38] Forecast demand requirements are also slightly higher (1.3%) through the medium term with energy requirements lower (1.3%) compared to the May 2022 filing. Forecast energy requirements are lower as a result of a small change in industrial requirements.

[34] 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.

[35] The energy outlook is conditioned by electricity prices. The underlying electricity rate aligns with Government of Newfoundland and Labrador's rate mitigation target of 14.7 cents per kWh, escalating at 2.25% per year. An estimated rate impact of generation expansion builds was also built-in to the rates for the Island Interconnected System load forecast. The rate impact from generation builds is considered a high level estimate of what the rate impact potential could be based on an estimate of the cost of builds over the forecast period.

[36] Refer to Volume III, Section 4.4 of the 2022 Update for further information on the Network Additions Policy.

[37] The existing customer's contract is for temporary service for a data center operation.

[38] Following the conclusion of work on the Network Additions Policy, it is expected that new contracts with firm and or non-firm customers will be established.

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

Table 3: Island Interconnected System Peak Demand Forecast (MW)[39]

	2023	2024	2025	2026	2027
Utility[40]	1,487	1,516	1,511	1,509	1,512
Industrial Customer	161	168	205	209	209
Island Interconnected System Customer Coincident Demand	**1,648**	**1,684**	**1,716**	**1,718**	**1,721**
Island Interconnected System Transmission Losses and Station Service	99	99	99	99	99
Total Island Interconnected System Demand	**1,747**	**1,783**	**1,815**	**1,817**	**1,820**

Table 4: Labrador Interconnected System Peak Demand Forecast (MW)[41]

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

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

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

[39] Numbers may not add due to rounding.
[40] The utility demand forecast includes approximately 22 MW of potential interruptible load in 2024 and 49 MW of potential interruptible load post 2024.
[41] Numbers may not add due to rounding.

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 be required to be maximized to ensure Hydro could continue to meet customer requirements in consideration of the historical dry sequence. This year 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 Interconnected System for three months during winter 2023.[42] 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 Muskrat Falls energy instead of Holyrood thermal energy. 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.

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.

At the end of October 31, 2022, the total system energy in storage was 2,144 GWh, 732 GWh above the minimum storage limit of 1,412 GWh for October 2022.

Figure 1 plots the 2021 and 2022 storage levels, maximum operating level storage, and the 20-year average aggregate storage for comparison.

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

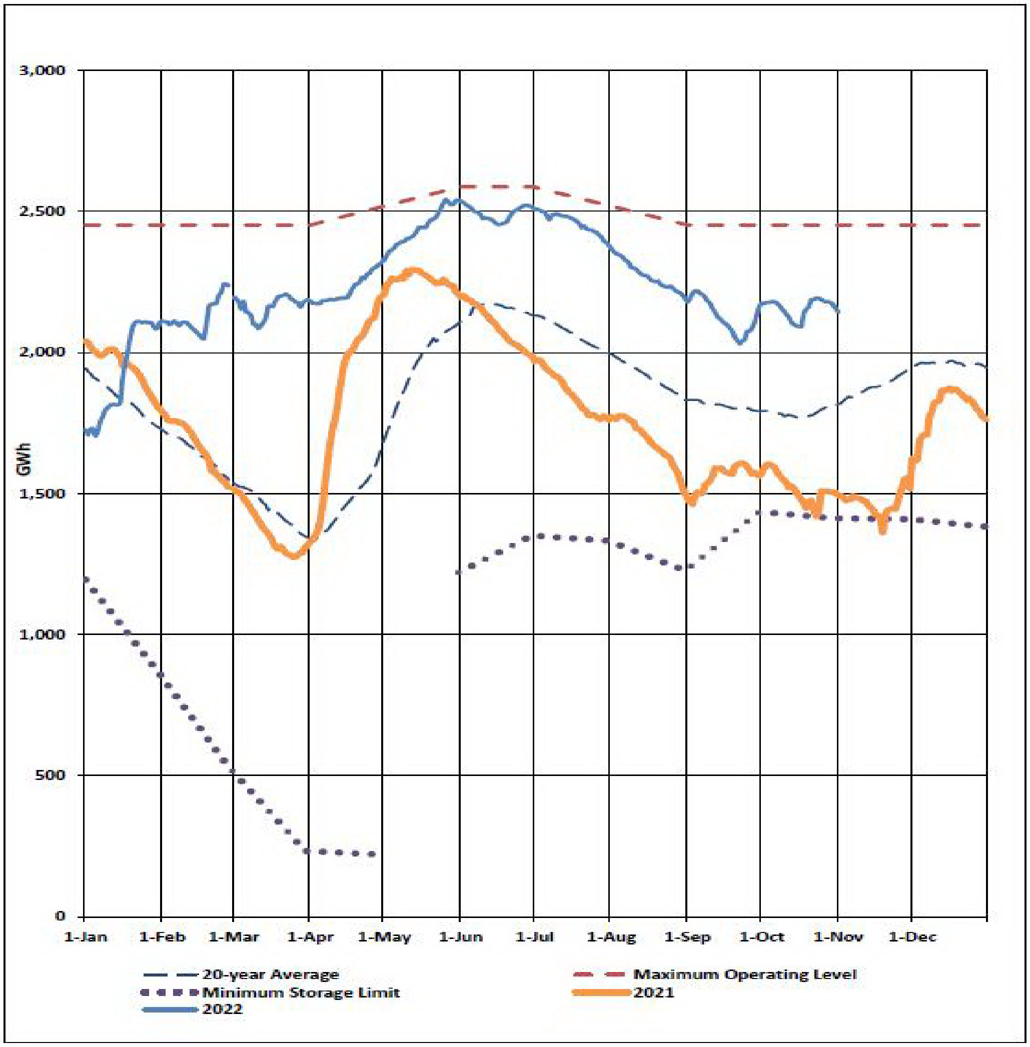

Figure 1: Total System Energy Storage for October 31, 2022

6.0 Results

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

6.1 Scenario Analysis

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

- **Scenario 1:** Assumes that the LIL will be available at 475 MW with a 10% bipole forced outage rate until January 2024 and 675 MW January 2024 with 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 GT 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 including 50 MW of imports during peak hours during the 2023 winter season.
- **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 assuming that the LIL is not available through the study period (2023–2027). The operation of Stephenville GT is extended through the study period at baseline forced outage rate as the operation of Holyrood TGS and Hardwoods GT are already assumed available through the study period.
- **Scenario 6:** Varies from Scenario 5 by increasing the Holyrood TGS DAFOR to the 2021 actual DAFOR of 34%.
- **Scenario 7:** Varies from Scenario 5 by including 50 MW of imports during peak hours during the winter season.
- **Scenario 8:** Varies from Scenario 5 by including 100 MW of imports during peak hours during the winter season.
- **Scenario 9:** Varies from Scenario 5 by including 150 MW of imports during peak hours during the winter season.

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 being 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 is in place until spring 2023. 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.

6.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 6.2.1 and 6.2.2 provide the results of the annual and monthly analysis, respectively.

6.2.1 Annual Assessment Results

Table 6 provides the annual LOLH, EUE and NEUE results. Note that the basis for comparison of 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. Given the level of uncertainty that remains, Hydro continues to recommend migrating to its proposed criteria of 0.1 LOLE when the Muskrat Falls Project has been fully commissioned and thermal generation at the Holyrood TGS, the Hardwoods GT, and the Stephenville GT has been retired. However, Hydro is committed to reassessing this recommendation as part of the 2023 Reliability and Resource Adequacy Study as Hydro continues to gather information while working with stakeholders.

Table 6: Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2023	2024	2025	2026	2027
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	1.0	0.6	0.9	0.9	0.9
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	3.1	1.8	2.5	2.4	2.5
Scenario 2A: Addition of 50 MW imports in 2023 only	1.8	N/A	N/A	N/A	N/A
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	1.0	1.3	1.8	1.7	1.8
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	1.0	0.2	0.2	0.2	0.2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	10.1	11.9	12.7	12.3	12.6
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	30.8	34.7	37.2	35.5	36.1
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	5.6	6.7	7.2	6.9	7.0
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	2.9	3.7	3.9	3.8	3.9
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	1.6	2.1	2.2	2.1	2.1

EUE (MWh)	2023	2024	2025	2026	2027
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	60	40	60	60	61
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	212	135	190	185	191
Scenario 2A: Addition of 50 MW imports in 2023 only	114	N/A	N/A	N/A	N/A
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	61	80	122	122	121
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	63	11	13	12	14
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	646	785	823	809	838
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	2166	2551	2729	2600	2658
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	331	402	437	421	431
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	165	211	226	213	229
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	83	105	116	109	112

NEUE (ppm)[43]	2023	2024	2025	2026	2027
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	5	4	5	5	5
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	19	12	16	16	16
Scenario 2A: Addition of 50 MW imports in 2023 only	10	N/A	N/A	N/A	N/A
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	5	7	10	10	10
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	6	1	1	1	1
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	57	68	71	70	72
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	192	222	234	224	229
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	29	35	38	36	37
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	15	18	19	18	20
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	7	9	10	9	10

The results of Scenarios 1–4 indicate that the availability of the LIL at partial capability, under various LIL bipole forced outage rate, and backed up by the Holyrood TGS and Hardwoods GT, mitigates the risk of lost load and unserved energy in the near term in almost all years, with the exception of the year 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

[43] NEUE, given here in ppm, represents lost load as a fraction of total system load. NERC recommends system operators consider NEUE a reliability metric, but a single target threshold has not been set. Different jurisdictions use targets ranging from 10 to 30 ppm.

rate assumptions in 2023. Scenario 2A indicates that imports of 50 MW on-peak during the 2023 winter period mitigate this risk. However, as stated in Section 3.2.1, there is no guarantee that an import contract would be available for this time period. The risk to system reliability decreases in 2024 in Scenario 2 when the LIL capacity increases to 675 MW and 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 Holyrood TGS and Hardwoods GT as a reliable generation stations in the near term.

Scenario 5 indicate that if the LIL is fully unavailable during the winter operating season, there is a material risk to system reliability in the near term, despite the continuation of Holyrood TGS, Hardwoods GT, and Stephenville GT. This is a shift from what was reported in the May 2022 Near-Term Reliability report due to a decrease in what is accounted for as Newfoundland Power's firm hydro capacity, a material increase in the forced outage rate used for Newfoundland Power's retiring thermal assets, and the projected load is slightly higher in the 2022 load forecast. With that said, progress has been made with integrating the Muskrat Falls assets to the Island Interconnected System, with the LIL currently tested and operated to 475 MW. It is expected that the LIL will be available in some capacity through the winter period.

The results of Scenario 6 demonstrate that if the LIL becomes unavailable through the study period concurrent with a high degree of unavailability at the Holyrood TGS, there is a considerable amount of system risk present. As both Scenarios 5 and 6 assess the extreme cases for both the LIL reliability and Holyrood TGS reliability, they are not likely to occur.

Finally, as demonstrated in Scenarios 7 and 8, imports over the Maritime Link could be used to reduce, but not fully mitigate the risk of generation shortfall in the event of the absence of the LIL through the study period. An import of 150 MW in the on-peak hours from December to March through the study period would be sufficient to reduce the risk of generation shortfall to an acceptable level in the most onerous modelled scenario.

6.2.2 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 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 Hardwoods GT through the study period and Stephenville GT until March 31, 2024, largely mitigates the risk of lost load and unserved energy. The winter months in 2023 have higher levels of LOLH and EUE, however, improvements are evident on a monthly basis once the LIL bipole forced outage rate is reduced from 10% in 2024 in Scenarios 1 and 4. 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 LIL increases.

The results of Scenarios 5–6 indicate that if the LIL is fully unavailable during the winter operating season, both LOLH and EUE grow as the unavailability of Holyrood TGS increases.

Finally, as seen in Scenarios 7 and 8, the import of firm energy over the Maritime Link produces an improvement in system reliability, however, does not fully mitigate the risk. As demonstrated in Scenario 9, a firm energy import of 150 MW during on-peak hours from December through March would be necessary to mitigate the risk in the near term. This demonstrates that retention of Stephenville as a generation unit and the use of firm imports could help mitigate the increased risk of resource shortfalls if the LIL is delayed or if it’s unavailability and/or reliability is worse than what is assumed 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 through 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 GT were sufficient to reduce rotating outages to approximately 100 MW at peak during the most severe conditions in the winter.[44] In the average case, almost all shortfall was covered by the extension of Holyrood TGS and Hardwoods GT.[45]

[44] While it is important to understand the implications of a six-week LIL shortfall and what is required to reduce/mitigate rotating outages for system planning purposes, it is not assessed against reliability metrics. Refer to Volume I of the 2022 Update for generation requirements to meet long-term reserve planning criteria.
[45] If projected load growth is higher than currently forecast, the projected shortfall will also increase.

Table 7: Monthly LOLH and EUE for 2023[46]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 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	0.2
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	1.5	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 2A: Addition of 50 MW imports in 2023 only	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 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, 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	0.2
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, 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	0.2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	5.3	2.1	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	14.6	7.0	3.4	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.1	5.3
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	3.0	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	1.7	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	0.9	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	34	12	3	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	111	46	19	0	0	0	0	0	0	0	0	35
Scenario 2A: Addition of 50 MW imports in 2023 only	61	24	10	1	0	0	0	0	0	0	0	17
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	31	12	6	0	0	0	0	0	0	0	0	10
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	36	11	5	0	0	0	0	0	0	0	0	10
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	365	120	52	2	1	0	0	0	0	0	0	105
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	1117	469	197	7	3	2	0	0	0	2	4	364
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	192	60	21	1	1	1	0	0	0	0	1	54
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	101	27	9	1	1	1	0	0	0	0	1	24
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	49	12	5	2	1	1	0	0	1	0	1	12

[46] 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 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	0.8	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	0.6	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 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	2.3	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.7
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	17.3	7.2	4.4	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.3	5.1
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	3.8	1.2	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.9
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	2.1	0.6	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	1.2	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	24	6	3	0	0	0	0	0	0	0	0	6
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	67	27	13	1	0	0	0	0	0	0	0	26
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	43	15	7	1	0	0	0	0	0	0	0	14
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	7	2	1	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	464	137	68	2	2	1	0	0	1	0	3	107
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	1406	489	269	11	5	3	0	0	0	0	11	354
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	246	64	32	2	2	0	0	0	0	0	2	53
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	128	35	13	3	1	1	0	0	1	0	2	28
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	66	14	5	2	1	1	0	0	0	0	2	13

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 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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 3: LIL at 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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%	6.5	2.7	1.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.0
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	17.2	8.6	4.7	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.3	5.8
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	3.9	1.4	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.0
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	2.1	0.7	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	1.2	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	34	12	5	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	100	40	19	1	0	0	0	0	0	0	1	28
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	68	22	11	1	0	0	0	0	0	0	1	19
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	7	2	1	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	455	162	73	3	2	1	1	0	0	0	2	123
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	1408	583	284	13	7	4	1	0	0	1	15	413
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	254	84	31	3	2	1	0	0	0	0	2	59
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	137	36	16	3	1	1	1	0	1	0	3	28
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	70	17	6	2	1	1	0	0	0	0	2	15

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 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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 3: LIL at 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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	2.4	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	17.1	7.9	4.3	0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.1	5.6
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	3.9	1.3	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	2.1	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	1.2	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	34	11	6	0	0	0	0	0	0	0	0	9
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	95	41	19	1	0	0	0	0	0	0	0	27
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	72	23	9	0	0	0	0	0	0	0	0	17
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	6	3	1	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	472	147	67	3	1	0	1	0	0	1	1	116
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	1400	532	257	10	4	4	1	0	1	3	3	387
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	256	75	32	2	1	1	1	0	1	1	1	52
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	128	35	14	2	1	1	0	0	0	1	1	30
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	67	17	5	2	1	1	0	0	0	1	1	13

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 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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 3: LIL at 475 MW to January 2024, increasing to 675 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 475 MW to January 2024, increasing to 675 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%	6.8	2.5	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	17.5	7.9	4.4	0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.1	5.6
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	3.9	1.3	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	2.3	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 20%	33	11	6	0	0	0	0	0	0	0	0	11
Scenario 2: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 5%, Holyrood TGS DAUFOP = 34%	100	41	18	1	0	0	0	0	0	0	0	29
Scenario 3: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 10%, Holyrood TGS DAUFOP = 20%	67	23	12	0	0	0	0	0	0	0	0	19
Scenario 4: LIL at 475 MW to January 2024, increasing to 675 MW, LIL bipole FOR = 1%, Holyrood TGS DAUFOP = 20%	8	2	2	0	0	0	0	0	0	0	0	2
Scenario 5: No LIL, Holyrood TGS DAUFOP = 20%	493	149	69	3	1	1	0	0	0	1	1	119
Scenario 6: No LIL, Holyrood TGS DAUFOP = 34%	1438	529	271	8	4	4	1	0	1	3	4	394
Scenario 7: No LIL, Holyrood TGS DAUFOP = 20%, 50 MW imports	261	72	34	3	1	1	0	0	0	1	1	58
Scenario 8: No LIL, Holyrood TGS DAUFOP = 20%, 100 MW imports	145	37	13	3	0	0	0	0	0	1	1	28
Scenario 9: No LIL, Holyrood TGS DAUFOP = 20%, 150 MW imports	69	16	7	2	1	1	0	0	0	1	1	14

7.0 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 GT as generating facilities until new generation can be integrated to the system, possibly through to 2030, in addition to maintaining the Stephenville GT until it's planned retirement by March 31, 2024.

In this analysis, Hydro has also presented results of system reliability metrics considering the assets: 1) in service as planned; 2) in service at levels that have already been demonstrated, and; 3) 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 the LIL is fully commissioned with multiple years of operational experience to better inform the selection of a bipole forced outage rate, the LIL capacity and bipole forced outage rate will be addressed with a range of upper and lower limits. As LIL performance statistics become available in the coming years, the bipole forced outage rate range can be narrowed in future filings. Hydro continues to monitor and mitigate the risks associated with the timing of the in-service of the LIL to supply off-island capacity and energy to the Island Interconnected System. 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.