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November 18, 2020

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

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Reliability and Resource Adequacy Study 2020 Update
Volume II: Near-Term Reliability Report

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") Near-Term Reliability Report (Volume II of the Reliability and Resource Adequacy Study). As previously communicated to the Board of Commissioners of Public Utilities ("Board") on October 2, 2020, Hydro expects to file Volumes I and II of the Reliability and Resource Adequacy Study on March 26, 2021.

In correspondence dated October 8, 2020, the Board requested that Hydro's Reliability and Resource Adequacy Study 2020 Update include the assessment of system reliability to 2024 with an assumption that the Labrador-Island Link will not be available for that period. Further, the Board requested an assessment of the ability of the Holyrood Thermal Generating Station to be extended as a generating plant beyond the current planned closure date of March 2023 until 2024 and an assessment of the implications of a permanent closure of the North Atlantic Refining Limited oil refinery. The enclosed report has been prepared to reflect the Board's requests.

Should you have any questions with respect to the information contained herein, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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Senior Regulatory Counsel
SAW/kd

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Reliability and Resource Adequacy Study 2020 Update

Volume II: Near-Term Reliability Report

November 18, 2020

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Contents

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1.0 Introduction

Supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Station ("Muskrat Falls GS") remains 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 through the full system transition.

This report discusses the near-term resource adequacy and reliability of the Newfoundland and Labrador Interconnected System for the study period, a four-year horizon from 2021–2024, and provides the results of the probabilistic resource adequacy assessment for the Newfoundland and Labrador Interconnected System for the study period. The analysis was conducted consistent with the methodology proposed in the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document" that provides modelling "practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments."[1]

The reliability indices in this near-term report include both annual and monthly Loss of Load Hours ("LOLH"), Expected Unserved Energy ("EUE"), and Normalized EUE.[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 was 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 can more easily be observed than by using an annual analysis only. As LOLH and EUE do not currently have generally acceptable criterion, unlike the generally accepted LOLE criterion of 0.1, the quantified results are presented to show how loss of load changes based on system conditions rather than for comparison against a threshold.

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

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 current evolving nature of the Newfoundland and Labrador Interconnected System, an analysis was conducted for each of the next four years (2021–2024) 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. In correspondence dated October 8, 2020, the Board requested that this report extend the assessment of system reliability to 2024 with an assumption that the Labrador-Island Link ("LIL") will not be available for that period. Further, the Board requested an assessment of the ability of the Holyrood TGS to be extended as a generating plant beyond the current planned closure date of March 2023 until 2024 and an assessment of the implications of a permanent closure of the North Atlantic Refining Limited ("NARL") oil refinery. This report has been prepared on that basis. Additional detail on activities required to ensure reliable service through the 2020–2021 winter operating season are provided in Section 7. An assessment of requirements to support the short-term extension of the Holyrood TGS, including to March 31, 2023 and 2024, is included as Appendix A.

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"), with updates to reflect current system assumptions. A detailed discussion of the initial modelling approach used can be found in Volumes I and II of the 2018 Filing. A discussion of changes to the model from the 2018 Filing can be found in Volume I of the "Reliability and Resource Adequacy Study 2019 Update," filed in November 2019 ("2019 Update"), and the "Near Term Reliability Report," filed on May 15, 2020 ("May Report").

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") Open Access Same-Time Information System ("OASIS") website.[3]

[3] NLSO Standard "Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, May 11, 2018.

3.0 Asset Reliability

On a quarterly basis, reports are filed with the Board which include actual forced outage rates and their relation to:

- The rolling 12-month performance of its units;[4]
- Past historical rates; and
- Assumptions used in assessment of resource adequacy.

The most recent report was submitted on October 30, 2020, for the quarter ending September 30, 2020. These reports detail unit reliability issues experienced in the previous 12-month period and compare performance for the same period year-over-year.

Hydro continues to take actions 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.

These actions are intended to support reliable unit operation and increase the likelihood of improved reliability in near-term operating seasons.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since filing its May Report. Updates on these items, as well as any additional items which 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 issues that are recurring in nature can have a significant impact on unit reliability if not managed properly. The information included 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 Probabilities ("DAUFOP").

The following sections provide a description of issues, both asset- and condition-based, that have previously affected generating unit reliability, as well as the current status of those issues and the

[4] Quarterly Report on Performance of Generating Units.

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, grouped by facility type:

- Hydraulic Facilities: New (Bay d'Espoir Unit 1 Vibration); continued monitoring (Bay d'Espoir penstocks and Upper Salmon rotor rim key cracking); ongoing (Granite Canal control system);
- Thermal Facilities: New (boiler feed pump motor issues); continued monitoring (unit boiler tubes); ongoing (variable frequency drives); and
- Gas Turbines: None noted.

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 Unit 1 Vibration

Bay d'Espoir Unit 1 was removed from service on May 31, 2020 to undergo its major preventative maintenance (PM9) overhaul. Following the return to service of the unit in July 2020 there was a noted increase in the generator vibration levels. This increase resulted in higher than normal vibration levels at loads between 55 and 65 MW.

Hydro completed a four-day outage on September 11, 2020 to investigate the vibration issue and determined that the generator guide bearing required adjustments to improve clearances. During this outage these adjustments were completed, critical clearance measurements were taken, and bolt torque was checked on embedded parts. Completion of these activities successfully reduced the vibration levels of the unit to an acceptable range allowing for the removal of the previously imposed operating restriction in the 55–65 MW load range.

Following the outage in September 2020, Hydro continued to monitor the trending data of Unit 1 and results from this period illustrated that the vibration levels have stabilized and are not increasing. Hydro will continue to monitor this data for additional time to ensure vibration levels remain stable over an extended operating period.

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.[5] In response to the most recent September 2019 failure of Penstock 1, SNC-Lavalin was engaged to complete an independent, detailed failure analysis of the most recent rupture, as well as an engineering review of the work previously completed by Hatch. The results of this failure analysis and engineering review were filed with the Board on June 3, 2020.[6] As outlined in that correspondence, Hydro is currently pursuing Stage 2, "Front End Engineering Design".

To mitigate potential impacts should another leak in Penstock 1 occur, proactive measures have been taken to reduce downtime. These actions include having an inventory of long lead time materials available (e.g., rolled steel plate), ensuring availability of welding resources, and engagement of an additional engineering consultant to ensure development of an appropriate long-term plan. Modifications to the Automatic Generator Control application in Hydro's Energy Management System designed to limit the amount of rough zone operation have also been implemented for Units 1–6 at Bay d'Espoir. A more prescriptive operating regime has been implemented for Units 1 and 2 at Bay d'Espoir, given the condition 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 inspection of Penstock 3, which was originally scheduled for completion in May 2020, was deferred to 2021 due to limitations associated with the onset of the COVID-19 pandemic. This decision was made in consultation with the consultant responsible for the penstock inspections and it was determined that Penstock 3 is safe for continued operation until the next scheduled inspection in 2021. Penstock 3 was last inspected in April 2019. The scheduled 2020 inspections for Penstocks 1 and 2 have been completed. Penstock 1 was inspected in July and Penstock 2 in October, and did not identify any major defects or areas of concern.

Upper Salmon Rotor Key Cracking

In 2018, the rotor rim keys on the Upper Salmon generating unit were replaced during the unit annual maintenance outage. As per consultation with the Original Equipment Manufacturer ("OEM"), Hydro has

[5] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018; "Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019; and "Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019.
[6] 2019 Faliure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension, Letter to Board from Hydro dated June 3, 2020.

continued to schedule and conduct regular inspections of the new rotor rim keys at Upper Salmon and will continue to monitor this situation throughout the anticipated wear-in period of the new keys and assess the effectiveness of the replacement keys. After a 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. No cracks were found from the filing of the 2019 Update until August 2020, when superficial cracks were found and resolved. Due to system constraints, the scheduled October 2020 inspection was delayed until the November 2020 winter readiness checks for the Upper Salmon unit. Hydro will review its approach to the rotor key cracking after the results of that November inspection.

Granite Canal Control System

A thorough engineering assessment of the system, in response to control system malfunctions experienced when remotely starting and/or stopping the Granite Canal unit, has been completed. Modifications to equipment as well as minor logical changes were implemented in 2019. Additional hardware and instrumentation modifications were implemented during the maintenance outage in June 2020 to address findings of the 2019 assessment. Further investigation is ongoing into remaining useful life of the control system; if necessary, any required capital work will be proposed as part of the capital budget process. An update will be provided in the May 2021 Near-Term Reliability Report.

3.1.2 Thermal

Boiler Feed Pump Motors

Hydro experienced a failure of the Unit 1 Boiler Feed Pump West on October 25, 2020. The failed Boiler Feed Pump was last overhauled in 2016 and scheduled for overhaul again in 2022. The pump was disassembled by plant crews under remote technical guidance from the Holyrood TGS Major Pump service provider. The impeller cartridge was found damaged and was replaced with the spare that is maintained on site. Other work was completed on the housing components and the pump was re-assembled ready for return to service on November 6, 2020. The spare motor was installed when it was observed that the motor had been provided set up for clockwise rotation and the pump requires counter-clockwise rotation. As a result the motor could not be used.

Unit 1 was put back on-line on November 7, 2020 with a deration to 70 MW which is what is achievable with one boiler feed pump. The isolation valves were replaced during the outage to allow further work on the west boiler feed pump and motor without requiring a further outage.

It was determined that reconfiguring the spare motor would result in the shortest return to service time line. The spare motor was reconfigured using available parts to correct the rotation direction at the local service shop. It was necessary to obtain parts from another spare boiler feed pump motor to complete the reconfiguration. This approach was reviewed and accepted by the motor OEM. The motor was installed on November 16 and pump and motor commissioning has been successfully completed. Hydro is working on obtaining parts to replace those replace the parts obtained from the other spare motor; however, a time line has not yet been established.

The motor rotor that was damaged during the failure event was sent to a shop in New Brunswick for refurbishment as it was determined, at the time of failure, to be the timeliest option available. It is not required for immediate service; however, the refurbishment of this motor is required to serve as a critical spare. The estimate for the return of the rotor to the island is two weeks. Approximately one week of work will be required to reassemble the motor and run additional electrical tests to verify the integrity during reassembly. It is expected that the motor will be available for use as a spare by late November or early December.

The damaged pump impeller cartridge has been sent to the Holyrood TGS Major Pump service provider’s shop in Ontario for refurbishment on an expedited basis. Once the condition is assessed a return date can be determined. Hydro will provide an update on progress in the December 2020 Winter Readiness 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 that are subjected to high temperatures and stresses. Boiler tubes are inspected on an annual basis to verify their condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts an annual tube inspection program, most recently completed during the 2020 annual outages. Hydro has determined that boiler tube sections, as a whole, are in good condition. Tube failures continue to pose a risk, particularly given the age of the Holyrood TGS boilers. Hydro maintains a thorough selection of spare tube material and will maintain a contract with an experienced boiler contractor for the provision of emergency repairs in the event of tube failures. As such, should a tube failure occur, the expected return to service time is accounted for in the projected DAFOR targets.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at the Holyrood TGS. The Variable Frequency Drives ("VFD") were installed to more efficiently vary the amount of air required based on generation need. This reduces auxiliary power requirements and results in fuel savings.

Hydro has entered into a service agreement with Siemens, and preventive maintenance work was completed by Siemens in 2018, 2019, and 2020 to address issues that have been encountered through VFD operation. Operating strategies have also been implemented to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups and erecting heated enclosures around the drive cabinets during the maintenance season to reduce contamination from moisture and dust. Despite these efforts, numerous VFD cell failures have occurred in preparation for the 2020–2021 operating season, similar to Hydro's experience in 2019. A total of 14 failed cells were sent to Siemens for refurbishment and have been returned. This number includes failures discovered during preventive maintenance work and failures that occurred during start-up of Unit 2 in June 2020.

Hydro is taking further action to reduce power cell failures. This includes a study to determine how drives can safely remain powered during outages. The study will be completed this coming winter, with a goal to implement solutions during the 2021 annual outages. Also planned is a study to establish a power cell reforming facility in-house. This would reduce the risk of power-up failures by allowing Hydro to re-energize cells in the same manner as the OEM.

During the 2019–2020 operating season there were two VFD related failures that led to unit trips. In both cases the unit was returned to service within a few hours.[7] An additional forced outage occurred on July 1, 2020 when Unit 1 had to be taken off line to replace a failed VFD power cell. In October 2020, Unit 1 tripped on October 25 and again on October 27. Both trips are suspected to be related to VFD issues. Investigations are underway with assistance from Siemens.

3.1.3 Gas Turbines

All issues identified in the May Report have been resolved. To date, there have been no additional issues of concern.

[7] On October 30, 2019, there was a trip on the Unit 2 east VFD. During this trip, the 4,160 V breaker failed to open, which caused an air damper to fail to close, disrupting proper airflow to the boiler and leading to a unit trip. On January 28, 2020, there was a trip on the Unit 2 west VFD due to the failure of a power cell.

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 ("FOR") provide a measure of the expected level of availability due to unforeseen circumstances.[8] Assumptions on FORs of generating units in this analysis have been updated in accordance with Hydro's FOR methodology.[9,10]

The FORs used in Hydro's reliability analysis vary by asset class, ownership, and condition. Appropriate FORs were determined based on historical data, where available, or the most recent industry average. The FOR is calculated using different metrics depending on the primary operating mode of the units. For units that primarily operate on a continuous basis, specifically units at Holyrood TGS and hydroelectric units, the FOR is based on the historical DAFOR. For units that primarily operate as peaking units, specifically gas turbine units, the FOR is based on the historical DAUFOP. Analysis was performed for a range of Holyrood TGS DAFOR assumptions to provide an indication of the sensitivity of supply adequacy to changes in Holyrood TGS availability. Industry information made available through the Canadian Electricity Association ("CEA") and NERC is used to determine FORs for units not owned by Hydro.

FOR assumptions are developed annually to incorporate the most recent data available. A detailed description of the development of the FOR assumptions used is found in Volume III, Attachment 1 of the 2019 Update. 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.

[8] 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.
[9] Hydro's current FOR methodology was provided in Attachment 5, Volume I of Hydro's 2018 Reliability and Resource Adequacy Study.
[10] In this report, Hydro deviated from the FOR methodology as outlined in the 2019 Update when selecting FORs 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 extended the capacity-weight average DAFOR from 3 to 5 years, increasing the FOR 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 FOR.

Table 1: Forced Outage Rates for Hydro-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 2.6%
Holyrood Thermal Units – Base Assumption	DAFOR = 15%
Holyrood Thermal Units – Sensitivity Assumptions	DAFOR = 18%, 20%
Holyrood Gas Turbine	DAUFOP = 4.9%
Happy-Valley Gas Turbine	DAUFOP = 12%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%
Diesels	DAUFOP = 8%

With respect to the LIL, once modelled as in service, the forced outage rate is modelled with a declining FOR (i.e. improving performance) in order to capture any testing activities and potential operational unknowns during the first years of operation.[11] For the purpose of this analysis, the LIL is assumed to be available at its full capacity on the in-service date, supported by the full availability of the Muskrat Falls generating units. It is assumed that delivery of the Nova Scotia Block[12] will also commence on that same in-service date.

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 = 5.7%
Gas Turbines	DAUFOP = 8%
Corner Brook Cogen	DAUFOP = 17.48%

Hydro models wind generation stochastically using probability distribution functions developed for summer and winter generation at each of the Fermeuse and St. Lawrence generating facilities.

Based on Hydro's experience with securing market purchases to date, import scenarios are contemplated as sensitivities to cases considered in this report; that is firm imports of 50 MW and

[11] In year 1 of operation, the monopole forced outage rate is assumed to be 10% for each pole. The forced outage rate assumption decreases to 2.5% in year 2, 1% in year 3, and finally to the long-term forced outage rate of 0.556% per pole from year 4 onwards.
[12] The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the Muskrat Falls GS on peak.

100 MW from December to March in winters before the LIL is placed in service, with an associated FOR intended to serve as 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 would 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. In advance of its planned retirement as a generating facility, the Holyrood TGS continues to be fully operational. Hydro has always intended to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls project assets. During this period of standby, the Holyrood TGS units would be fully available for generation. In correspondence dated September 28, 2020, Hydro advised the Board of an extension to the operations of the Holyrood TGS as a generating facility to March 31, 2023.[13] Beyond the retirement date, 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. For the purposes of this analysis, in the scenarios where the LIL remains unavailable throughout the study period (2021–2024), the Holyrood TGS is assumed to be available for the entirety of the study period.

3.3.2 Hardwoods and Stephenville Gas Turbines

The Stephenville Gas Turbine (“Stephenville GT”) consists of two 25 MW gas generators that were commissioned in 1975. The Hardwoods Gas Turbine (“Hardwoods GT”) consists of two 25 MW gas generators that were 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. These units were planned to be retired in 2021.

As identified in the most recent transmission planning assessment,[14] following the retirement of the Stephenville GT, backup supply for the area will be addressed by the addition of a 230/66 kV,

[13] Hydro previously communicated an extension to March 31, 2022 in correspondence “Extension of Holyrood Thermal Generation Station as a Generating Facility,” Newfoundland and Labrador Hydro, February 14, 2020.
[14] The 2020 Final Annual Planning Assessment was posted to the NLSO OASIS site on May 7, 2020.

40/53.3/66.7 MVA power transformer at the Bottom Brook 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 TL 209. This project was included in Hydro's 2021 Capital Budget Application. As this project will take two years to complete, it is expected that the Stephenville GT will be retired following completion of this project in 2023.[15]

With respect to the Hardwoods GT, operating hours and generation at this facility has decreased materially in the past two years from levels observed in 2014 through 2018 and asset availability at these facilities is much improved over levels previously observed.[16] Given continued uncertainty regarding the reliable in-service of the LIL, Hydro proposes to retain the Hardwoods GT in service until the LIL is proven reliable. Hydro 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. However, Hydro will re-evaluate the decision to retain all or portions of the assets in service should extensive maintenance or incremental capital expenditures are required to facilitate this life extension.

As such, for the purposes of this report it is assumed that the Stephenville GT and Hardwoods GT will be retired on the same schedule as the Holyrood TGS. This is modelled as March 31, 2023, reflective of the full power in-service of the Muskrat Falls asset on September 30, 2021.[17] An additional scenario assumes that the LIL will not be available through the study period (2021–2024). In this scenario, both the Hardwoods GT and Stephenville GT 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

[15] A fully established LIL is also a pre-requisite for the retirement of the Stephenville GT.
[16] This reduction in the requirement to operate is primarily attributed to the high degree of reliability observed at Holyrood TGS, 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.
[17] As per the September 28, 2020 correspondence to the Board.

Interconnected System and Labrador Interconnected System, rural isolated systems, as well as by utility load[18] and industrial load[19]. 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. For the current analysis, Hydro has updated its provincial load forecast outlook to reflect the latest available load forecast information from its industrial customers, Newfoundland Power, and Hydro's own rural service territories.

4.2 Economic Setting[20]

While the province has experienced a low volume of COVID-19 cases to date as compared to other parts of the country and the world, the Newfoundland and Labrador economy in 2020 has been challenged by the global economic impacts of the COVID-19 pandemic.

For 2020, the provincial government is forecasting declines for many economic measures including employment, real exports, capital investment and real GDP, with COVID-19 related work shutdowns and work suspensions cited as a contributing factor. The forecast decrease in real exports is largely a result of reduced fish and refined petroleum exports. The future for refined petroleum exports remains at risk given the uncertainty that surrounds oil refining operations at Come By Chance. Travel restrictions associated with the COVID-19 pandemic are expected to result in lower tourism activity for 2020.

On a more positive note, consumer price inflation remains low and household income in 2020 is expected to rise due to federal COVID-19 related compensation programs that will offset declines in employment compensation. Despite subdued activity within the provincial offshore oil sector, recently announced oil discoveries and longer term exploration plans and programs bode well for future growth in this industry. Forecast provincial housing starts for 2020 are on par with 2019 and indicate that the steep declines recently experienced are beginning to stabilize. On the Island, 2020 newsprint shipments are expected to mirror 2019 levels while both lumber production and farm cash receipts are expected to rise. In Labrador, construction of the underground mine at Voisey's Bay resumed following a work suspension in the spring in response to the COVID-19 pandemic. As there were little or no COVID-19

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[18] Residential and general service loads of Newfoundland Power and Hydro.
[19] Larger direct customers of Hydro such as CBPP, NARL, Vale Newfoundland and Labrador Limited ("Vale"), Praxair Canada Inc., Iron Ore Company of Canada, and Tacora Resources Inc. ("Tacora")
[20] The economy and forecast load requirements reflected in this report do not include impacts associated with an extended period of a global COVID-19 pandemic. With respect to the pandemic, Hydro has modelled a change to 2021 energy requirements only, associated with the known impacts of COVID-19 (e.g., reduced requirements at NARL). Economic commentary reflects "The Budget 2020, Government of Newfoundland & Labrador".

impacts on iron ore production, the value of mineral exports in 2020 is also expected to increase. Increased production levels at Tacora mine was a contributing factor to increased ore production.

With the provincial Government's fiscal situation remaining relatively challenging and an overall muted economic environment, the underlying local market conditions for electric power operations suggest stable or possible modest decline for the near term followed by a return to increasing power requirements once economic conditions improve.

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,[21] Newfoundland Power,[22] as well as Hydro's forecasts of load requirements for its rural service territories[23] and for the Newfoundland Power service territory.[24] Since the last load forecast update used in Hydro's May Report, Hydro has updated its Island Interconnected System utility load forecasts and received industrial power requests for 2021. Hydro relied on these inputs to determine a five-year forecast of customer energy and coincident demand for the Island Interconnected System, Labrador Interconnected System, and Newfoundland and Labrador Interconnected System.

Changes in forecast Island Interconnected System load requirements since the filing of the May Report include a change to 2021 energy requirements associated with the known impacts of COVID-19,[25] and minor changes in forecast Island Interconnected System energy requirements across the remainder of the forecast period. Since the May 2020 forecast update Hydro has also reviewed the forecast peak demand requirements for the Newfoundland Power system. At present, Hydro's forecast annual peak demand requirements for the Newfoundland Power system continue to reflect a conservative view of probable demand savings associated with existing and projected heat pump installations through the

[21] Includes updated firm power requests for 2021.
[22] Includes Newfoundland Power's forecast of annual system energy requirements for 2021 and 2022. Newfoundland Power's load forecast was prepared in April 2020.
[23] 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. The Labrador East and West load forecasts were prepared in April 2020. The Island Interconnected load forecast was prepared during the summer of 2020.
[24] Includes Hydro's forecast of post 2022 annual energy requirements for the Newfoundland Power system. Includes Hydro's forecast of Newfoundland Power system peak demand requirements for all forecast years. Hydro updated its load forecast of the Newfoundland Power system during the summer and fall of 2020.
[25] Primarily reflects impact of the idled oil refinery at Come by Chance that is assumed to return to production prior to 2022. The impact on load resulting from a permanent closure of the refinery is approximately 28 MW, exclusive of losses. In accordance with the Board's communication of October 8, 2020, this case has been analyzed as a sensitivity to Hydro's base forecast.

medium term. Hydro considers both Newfoundland Power's and its own forecast results for Newfoundland Power system demand to be probable future outcomes but considers its conservative approach and modestly higher demand forecast to be prudent for assessments of system reliability and resource adequacy until the results of Newfoundland Power's on-going heat pump study can be statistically quantified and validated. Joint discussion and reviews of system demand data and forecasting methodologies with Newfoundland Power has resulted in a modest reduction in Hydro's forecast peak demand requirements for the Newfoundland Power system through the medium term. Hydro's current forecast of Newfoundland Power system peak demand requirements remains approximately 3–4% (approximately 40–50 MW) higher than Newfoundland Power's internal forecast through the medium term.

Overall, the forecast Island Interconnected System utility power and energy requirements through the medium term continue to reflect a mostly stagnant outlook for the provincial economy.

In Labrador, the successful re-activation of Scully Mine by Tacora has resulted in additional power requirements on the Labrador Interconnected System. Actual power requirements for this customer to date indicate loads to be comparable with the former operator's power requirements.[26] Forecast Labrador Interconnected System industrial energy requirements for this update continue to reflect the energy forecast update completed by Hydro in April 2020 but includes a minor increase in forecast firm[27] power requirements for the unregulated industrial customers. Forecast utility power and energy requirements through the medium term also remain largely unchanged from Hydro's previous load forecast update, although Hydro has observed that power requirements associated with some approved data centre applications are lagging these customers' initial load growth timelines. Hydro's near-term Labrador Interconnected System load forecast continues to reflect the unresolved power supply constraints to the western Labrador system while slightly higher requirements are forecast beyond the near-term, assuming the power supply constraints are resolved.

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

[26] Tacora has advised Hydro that increased power requirements are likely for its mining operations in the future but no firm commitments on timing and the increase have been made at this time. These increased power requirements are not included in Hydro's current load forecast.
[27] LIS industrial firm power is subject to curtailment in periods when Labrador West system demands exceed current power transfer constraints.

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

	P50			
	2021	**2022**	**2023**	**2024**
Utility	1,476	1,476	1,477	1,481
Industrial Customer	152	180	180	180
IIS[28] Customer Coincident Demand	**1,628**	**1,656**	**1,657**	**1,661**
IIS Transmission Losses and Station Service	71	103	101	101
Total IIS Demand	**1,699**	**1,759**	**1,758**	**1,762**

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

	P50			
	2021	**2022**	**2023**	**2024**
Utility	141	143	143	144
Industrial Customer	279	278	301	301
LIS[29] Customer Coincident Demand	**420**	**421**	**444**	**445**
LIS Transmission Losses and Station Service	24	24	26	26
Total LIS Demand[30]	**444**	**445**	**470**	**471**

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

	P50			
	2021	**2022**	**2023**	**2024**
NLIS[31] Customer Coincident Demand	2,048	2,077	2,101	2,106
NLIS Transmission Losses and Station Service	95	127	127	127
Total NLIS Demand	**2,143**	**2,204**	**2,228**	**2,233**

5.0 System Energy Capability

In May 2020, Hydro established minimum storage limits[32] to April 30, 2021 in consideration of potential delays in the availability of the LIL to deliver energy to the Island Interconnected System. This will help ensure sufficient storage to reliably serve customers should the LIL continue to be delayed beyond winter 2020–2021. The limits do not consider the availability of imports, 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

[28] Island Interconnected System ("IIS").
[29] Labrador Interconnected System ("LIS").
[30] Overall peak load requirements for the Labrador Interconnected System are less than the total available generation capacity from the Recall and TwinCo blocks (approximately 532 MW).
[31] Newfoundland and Labrador Interconnected System ("NLIS").
[32] In the current system, these limits represent the point at which Holyrood generation would be required to be maximized to ensure Hydro could continue to meet customer requirements in consideration of the historical dry sequence.

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, 2020, the total system energy in storage was 1,804 GWh; 398 GWh above the minimum storage limit of 1,406 GWh for October 2020. Figure 1 plots the 2020 and 2019 storage levels, minimum storage limits, maximum operating level storage, and the 20-year average aggregate storage for comparison.

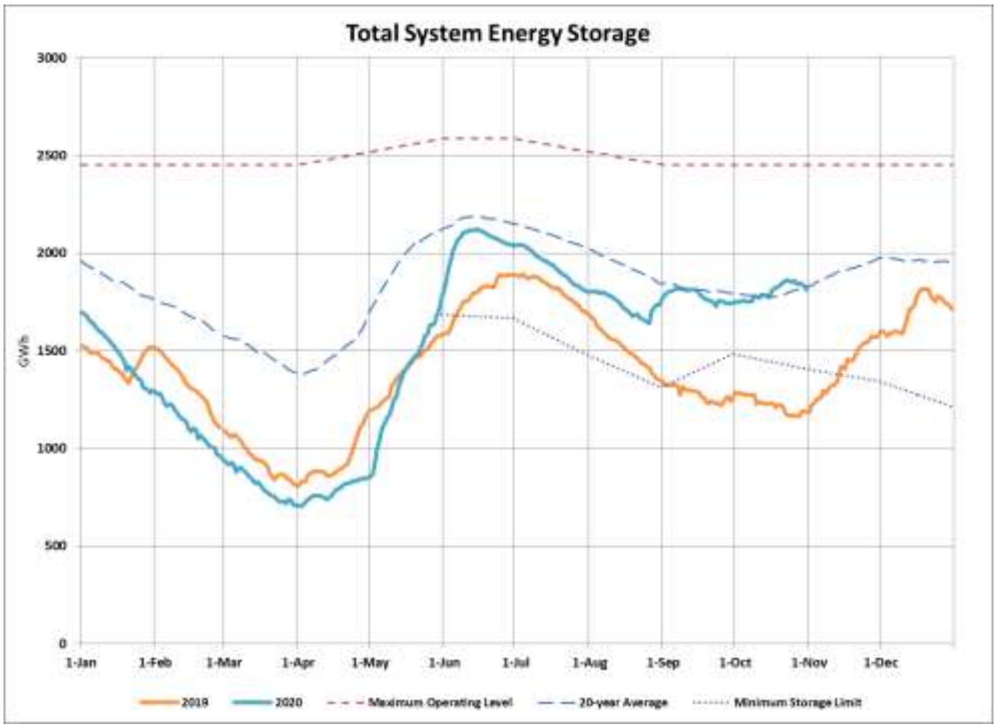

Figure 1: Total System Energy Storage for October 31, 2020

With the availability of thermal energy and access to external markets to provide the balance of load, the availability of energy in reservoir systems does not currently pose a risk to near-term resource adequacy.

6.0 Results

The following subsections provide a description of the 12 scenarios considered and the anticipated system reliability in each scenario (i.e., LOLH, EUE, and normalized EUE results).

6.1 Scenario Analysis

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

- **Scenario 1:** Assumes that the LIL will be available at full capacity in September 2021. This case assumes a DAFOR of 15% for the Holyrood TGS as well as the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT on March 31, 2023. No LIL deliveries are contemplated in advance of September 2021 in this modelled scenario.
- **Scenario 2**: Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 3:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 4:** Varies from Scenario 3 by including 50 MW of imports during the winter season.
- **Scenario 5:** Varies from Scenario 3 by including 100 MW of imports during the winter season**.**
- **Scenario 6:** Varies from Scenario 1 by assuming that the LIL is not available through the study period (2021 through the end of 2024). The operation of Holyrood TGS, Hardwoods GT, and Stephenville GT is extended through the study period at baseline FORs.
- **Scenario 7:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 8:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 9:** Varies from Scenario 8 by including 50 MW of imports during the winter season.
- **Scenario 10:** Varies from Scenario 8 by including 100 MW of imports during the winter season.
- **Scenario 11:** Varies from Scenario 6 by excluding industrial load from North Atlantic Refining Ltd.
- **Scenario 12:** Varies from Scenario 8 by excluding industrial load from North Atlantic Refining Ltd.

For Scenarios 1–5 and 11–12 it is assumed that the contract for capacity assistance with Vale Newfoundland and Labrador Limited ("Vale") is renewed for the 2020–2021 winter operating season.

For scenarios 6–10 it is assumed that the contract for capacity assistance with Vale is renewed for each winter season in the study period.

For Corner Brook Pulp and Paper ("CBPP") Capacity Assistance the existing contract runs until Spring 2022. In Scenarios 1–5 this remains unchanged. In Scenarios 6–12, it is assumed that the CBPP Capacity Assistance remains in place throughout the study period.

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 normalized EUE results. Note that the basis for comparison of results is Hydro's existing LOLH criterion of not more than 2.8 hours per year. Hydro intends to migrate to its proposed criteria of 0.1 LOLE when the Muskrat Falls project has been fully commissioned and thermal generation at the Holyrood TGS, Hardwoods GT, and Stephenville GT has been retired.

Where scenarios are no longer relevant (i.e., the increase in DAFOR for the Holyrood TGS no longer varies the LOLH or EUE once the plant has been is retired), the results have been noted as not applicable ("N/A").

Table 6: Annual LOLH, EUE, and Normalized EUE Results

LOLH (hours)	2021	2022	2023	2024
S1: LIL 2021, Holyrood TGS DAFOR = 15%	1.64	0	0.12	0.39
S2: LIL 2021, Holyrood TGS DAFOR = 18%	2.54	0.01	0.12	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	3.23	0.01	0.12	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	1.64	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	0.79	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	2.09	3.2	3.21	3.67
S7: No LIL, Holyrood TGS DAFOR = 18%,	3.16	4.82	4.78	5.44
S8: No LIL, Holyrood TGS DAFOR = 20%	4.14	6.05	6.16	7.01
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	2.1	3.21	3.21	3.66
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	1.05	1.67	1.67	1.88
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	N/A	2.08	2.09	2.42
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	N/A	4.05	4.1	4.65

EUE (MWh)	2021	2022	2023	2024
S1: LIL 2021, Holyrood TGS DAFOR = 15%	83	0	12	38
S2: LIL 2021, Holyrood TGS DAFOR = 18%	135	1	10	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	171	1	11	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	80	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	35	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	111	172	172	201
S7: No LIL, Holyrood TGS DAFOR = 18%,	167	263	263	304
S8: No LIL, Holyrood TGS DAFOR = 20%	222	337	344	401
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	104	168	166	194
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	48	80	80	93
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	N/A	108	108	127
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	N/A	220	222	258

Normalized EUE (ppm)[33]	2021	2022	2023	2024
S1: LIL 2021, Holyrood TGS DAFOR = 15%	10.12	0.04	1.42	4.64
S2: LIL 2021, Holyrood TGS DAFOR = 18%	16.32	0.08	1.24	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	20.77	0.08	1.3	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	9.63	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	4.21	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	13.05	19.9	19.82	23.13
S7: No LIL, Holyrood TGS DAFOR = 18%,	19.74	30.47	30.41	34.97
S8: No LIL, Holyrood TGS DAFOR = 20%	26.19	39.05	39.76	46.17
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	12.2	19.47	19.15	22.3
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	5.68	9.21	9.21	10.61
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	N/A	12.95	12.84	15.1
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	N/A	26.25	26.4	30.56

Higher levels of LOLH and EUE are observed in all scenarios during 2021, resultant from the LIL being unavailable during the winter operating season, with both LOLH and EUE growing as the unavailability of Holyrood TGS increases. In Scenarios 1–5, the LOLH and EUE drop significantly once the LIL is in service in September 2021 and remain at acceptable levels through the remainder of the study period. In Scenarios 6–10, where the LIL remains unavailable, the EUE and LOLH remain higher throughout the study period.

[33] Normalized EUE given here in parts per million and it 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.

Based on these results, it can be observed that there is an increased risk of generation shortfall until the LIL is in service, with the amount of risk highly dependent on the availability of the Holyrood TGS.[34] As demonstrated in Scenarios 4, 5, 9 and 10, imports over the Maritime Link could be used to mitigate the risk of generation shortfall. An import of 100 MW in the on-peak hours from December to March would be sufficient to reduce the risk of generation shortfall to an acceptable level in the most onerous modelled scenario.

The NARL-adjusted scenarios (i.e., NARL shutdown), Scenarios 11 and 12, which start in 2022 and assume the LIL will be unavailable, show improved reliability relative to Scenarios 6 and 8 and that overall reliability would be highly dependent on the availability of Holyrood.

Note that these results show lower LOLH and EUE values than the May 2020 Report in comparable scenarios. This can mostly be attributed to a decreased peak load forecast, with slight changes in forced outage rates having smaller effects.

6.2.2 Monthly Assessment Results

Table 7 through Table 10 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 allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for 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.

High values of LOLH and EUE are observed in all scenarios during the winter months of 2021, with both LOLH and EUE growing as the Holyrood TGS unavailability increases.

In Scenarios 1 to 5, LOLH and EUE are observed to decrease significantly as generation becomes available at the Muskrat Falls GS and the LIL enters normal operation, resulting in a low value of LOLH and EUE during the winter of 2021–2022 when Holyrood TGS and the LIL are both in-service. Once

[34] For reference, the weighted average thermal DAFOR for 12 months ending September 2020 was 2.08% as reported in the Quarterly Report on Performance of Generating Units for the Quarter Ended September 30, 2020, filed with the Board on October 30, 2020.

Holyrood TGS and the Hardwoods and Stephenville GTs are retired, LOLH increases but remains at acceptable levels through the study period.

In Scenarios 6 to 8, the LOLH and EUE remain high throughout the study period, and without mitigation, indicate a relatively high probability of lost load on the system until the LIL is found fully reliable.

As seen in Scenarios 4, 5, 9 and 10, the import of firm energy over the Maritime Link produces a significant improvement in system reliability. This demonstrates that firm imports could mitigate the increased risk of resource shortfalls if the LIL is delayed or if the Holyrood TGS or other generating assets were to perform more poorly than expected.

It is important to note that it has been assumed that the LIL will not be available in advance of September 2021. If the LIL is available, even at the level of availability experienced in the winter of 2018–2019, it would have a significant positive impact on system reliability.

Table 7: Monthly LOLH and EUE for 2021[35]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.77	0.51	0.35	0	0	0	0	0	0	0	0	0.01
S2: LIL 2021, Holyrood TGS DAFOR = 18%	1.18	0.79	0.55	0	0	0	0	0	0	0	0	0.01
S3: LIL 2021, Holyrood TGS DAFOR = 20%	1.51	1.01	0.69	0.01	0	0	0	0	0	0	0	0.01
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	0.76	0.5	0.35	0.01	0	0	0	0	0	0	0	0.01
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	0.37	0.22	0.18	0	0	0	0	0	0	0	0	0.01
S6: No LIL, Holyrood TGS DAFOR = 15%	0.77	0.51	0.35	0	0	0	0	0	0	0	0.02	0.44
S7: No LIL, Holyrood TGS DAFOR = 18%,	1.16	0.78	0.54	0	0	0	0	0	0	0	0.03	0.64
S8: No LIL, Holyrood TGS DAFOR = 20%	1.52	1.02	0.73	0.01	0	0	0	0	0	0	0.05	0.82
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	0.76	0.5	0.34	0.01	0	0	0	0	0	0	0.05	0.43
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.36	0.24	0.16	0	0	0	0	0	0	0	0.04	0.23
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[35] Monthly results may not add up to annual results – this is due to rounding.

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	39	25	18	0	0	0	0	0	0	0	0	0
S2: LIL 2021, Holyrood TGS DAFOR = 18%	63	41	29	0	0	0	0	0	0	0	0	1
S3: LIL 2021, Holyrood TGS DAFOR = 20%	81	52	37	0	0	0	0	0	0	0	0	1
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	39	23	17	0	0	0	0	0	0	0	0	1
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	16	10	8	0	0	0	0	0	0	0	0	1
S6: No LIL, Holyrood TGS DAFOR = 15%	37	26	18	0	0	0	0	0	0	0	1	25
S7: No LIL, Holyrood TGS DAFOR = 18%,	62	41	27	0	0	0	0	0	0	0	2	37
S8: No LIL, Holyrood TGS DAFOR = 20%	81	53	39	0	0	0	0	0	0	0	2	47
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	39	23	17	0	0	0	0	0	0	0	2	24
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	16	10	8	0	0	0	0	0	0	0	2	11
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 8: Monthly LOLH and EUE for 2022

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0	0	0	0	0	0	0	0	0	0	0	0
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	0	0
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	1.21	0.78	0.5	0.01	0	0	0	0	0	0	0.04	0.67
S7: No LIL, Holyrood TGS DAFOR = 18%,	1.79	1.18	0.8	0.01	0	0	0	0	0	0	0.05	0.99
S8: No LIL, Holyrood TGS DAFOR = 20%	2.29	1.47	1	0.01	0	0	0	0	0	0	0.08	1.2
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.2	0.74	0.52	0.01	0	0	0	0	0	0	0.07	0.66
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.59	0.39	0.26	0.01	0	0	0	0	0	0	0.07	0.34
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	0.78	0.49	0.33	0	0	0	0	0	0	0	0.02	0.46
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	1.54	0.97	0.68	0	0	0	0	0	0	0	0.04	0.8

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0	0	0	0	0	0	0	0	0	0	0	0
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	0	0
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	63	40	27	0	0	0	0	0	0	0	2	38
S7: No LIL, Holyrood TGS DAFOR = 18%,	98	62	43	0	0	0	0	0	0	0	2	58
S8: No LIL, Holyrood TGS DAFOR = 20%	127	79	56	0	0	0	0	0	0	0	4	71
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	62	36	27	0	0	0	0	0	0	0	4	39
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	28	18	12	0	0	0	0	0	0	0	4	18
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	40	25	17	0	0	0	0	0	0	0	1	26
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	83	50	37	0	0	0	0	0	0	0	2	47

Table 9: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0.01	0	0	0	0	0	0	0.01	0.1
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0	0	0	0.01	0	0	0	0	0	0	0.01	0.09
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0.01	0	0	0	0	0	0	0.01	0.09
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	1.12	0.81	0.49	0.01	0	0	0.01	0	0	0	0.04	0.73
S7: No LIL, Holyrood TGS DAFOR = 18%,	1.68	1.22	0.73	0.01	0	0	0.01	0	0	0	0.06	1.07
S8: No LIL, Holyrood TGS DAFOR = 20%	2.18	1.58	0.96	0.01	0	0	0.01	0	0	0	0.08	1.34
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.13	0.81	0.49	0.01	0	0	0.01	0	0	0	0.08	0.68
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.55	0.4	0.25	0.01	0	0	0.01	0	0	0	0.08	0.37
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	0.74	0.53	0.31	0	0	0	0	0	0	0	0.02	0.47
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	1.48	1.06	0.61	0.01	0	0	0	0	0	0	0.05	0.89

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	1	10
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0	0	0	0	0	0	0	0	0	0	1	8
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	1	0	0	0	0	0	0	1	9
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	60	41	26	0	0	0	0	0	0	0	2	42
S7: No LIL, Holyrood TGS DAFOR = 18%,	90	66	41	0	0	0	0	0	0	0	3	63
S8: No LIL, Holyrood TGS DAFOR = 20%	120	87	55	0	0	0	0	0	0	0	4	78
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	57	41	26	0	0	0	0	0	0	0	4	38
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	27	19	11	0	0	0	0	0	0	0	4	19
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	38	27	16	0	0	0	0	0	0	0	1	26
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	77	56	33	0	0	0	0	0	0	0	2	54

Table 10: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.14	0.11	0.07	0.01	0	0	0	0	0	0	0	0.07
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	1.53	0.84	0.65	0.01	0	0	0	0	0	0	0	0.64
S7: No LIL, Holyrood TGS DAFOR = 18%,	2.27	1.3	0.95	0.01	0	0	0	0	0	0	0	0.91
S8: No LIL, Holyrood TGS DAFOR = 20%	2.93	1.68	1.23	0.02	0	0	0	0	0	0	0	1.14
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.56	0.83	0.62	0.01	0	0	0	0	0	0	0	0.63
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.76	0.43	0.32	0.01	0	0	0	0	0	0	0	0.34
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	1.02	0.53	0.44	0	0	0	0	0	0	0	0	0.42
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	1.99	1.07	0.81	0.01	0	0	0	0	0	0	0	0.78

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	14	11	7	0	0	0	0	0	0	0	0	6
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	83	45	36	0	0	0	0	0	0	0	0	37
S7: No LIL, Holyrood TGS DAFOR = 18%,	127	70	52	0	0	0	0	0	0	0	0	54
S8: No LIL, Holyrood TGS DAFOR = 20%	167	93	69	1	0	0	0	0	0	0	0	70
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	82	43	32	1	0	0	0	0	0	0	0	36
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	37	21	15	1	0	0	0	0	0	0	0	19
S11: No LIL, Holyrood TGS DAFOR: 15%, NARL-adjusted forecast	54	27	23	0	0	0	0	0	0	0	0	23
S12: No LIL, Holyrood TGS DAFOR: 20%, NARL-adjusted forecast	108	58	45	0	0	0	0	0	0	0	0	47

7.0 System Reliability in Advance of Full In-service of the LIL

In its correspondence dated March 5, 2020, the Board requested that Hydro's May 2020 near-term generation adequacy report include a detailed plan and schedule describing all activities required to ensure winter 2020–2021 service reliability under the assumption that the LIL will not be available during some or all of that period, as well as similar analysis for winter 2021–2022 on the same basis. Hydro has reflected the Board's March request in this report as well.

The following sections provide information on Hydro's plan to ensure the reliable electricity supply for customers in the near-term.

7.1 Ensuring Reliability of Existing Generating Assets

Existing assets and infrastructure continue to play a key role in Hydro's supply mix through the study period. Reasonable assumptions regarding the availability and reliability of existing assets, used in the analysis which supports this report, ensures that the system is not relying on assets beyond their expected capability and that the firm capability and forced outage rates are appropriately considered.

Similar to other years, though increasingly important in consideration of the continued COVID-19 pandemic, Hydro is proactively managing its Integrated Annual Work Plan, as well as its short-term planning and work scheduling to safely execute critical maintenance and capital work activities to maintain: (1) the reliable operation of electricity production and transmission assets through the 2020–2021 winter season, and (2) to undertake asset-related activities to conform to legislated requirements. Hydro continues to ensure its workforce is being deployed to complete high priority work, with controls in place to protect the safety and health of its workforce and people in the communities in which Hydro operates and travels.

Updates on completion of corrective and preventive maintenance required to ensure assets are reliable in advance of the winter operating season are provided to the Board through Hydro's Winter Readiness Planning Reports, filed in October, November and December annually. Similarly, updates on progress on capital projects in the current year are provided as part of Hydro's Capital Budget Application, filed annually in August. In light of the COVID-19 pandemic, Hydro recognized that for the current year it may be helpful to provide an update on the progress of its winter readiness activities in advance of October 2020. Therefore, Hydro submitted a winter readiness report to the Board in September 2020 which included an overview of Hydro's winter readiness position.

7.2 Ensuring Sufficient Energy to Meet Customer Requirements

As discussed in Section 5, Hydro establishes minimum storage limits annually to ensure that it is capable of meeting customer energy requirements. In the current system, these limits represent the point at which Holyrood generation would be required to be maximized to ensure Hydro's ability to meet customer requirements in consideration of the historical dry sequence.

Hydro established minimum storage limits to April 30, 2021 which assume that the LIL remains unavailable through the winter of 2020–2021. This will help ensure sufficient storage to reliably serve customers should the LIL continue to be delayed.

With the availability of thermal energy and access to external markets to provide the balance of load, the availability of energy in reservoir systems does not currently pose a risk to near-term resource adequacy. Further, while it has been assumed for the purpose of establishing these targets that the LIL will not be available through this upcoming winter, deliveries over the LIL would increase the amount of economic energy available to the Island Interconnected System, which would reduce the amount of higher cost energy required to maintain sufficient energy in storage.

In addition, regular assessments of storage at a reservoir level basis will continue to be completed to ensure that each hydraulic generating unit remains capable of producing at full rated output through the winter period.

7.3 Extension of Holyrood Thermal Generating Station as a Generating Facility and Proposed Extension of Hardwoods and Stephenville Gas Turbines

As discussed in Section 3.3.1, Hydro has always intended to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls project assets. In correspondence dated September 28, 2020, Hydro advised the Board of an extension to the operations of Holyrood TGS as a generating facility to March 31, 2023. The decision to extend operations of Holyrood TGS at that time was made to help ensure Hydro's ability to reliably supply customers while the Muskrat Falls project assets are brought online and proven reliable.

As discussed in section 3.3.2, given continued uncertainty regarding the reliable in-service of the LIL, Hydro proposes to retain the Hardwoods GT in service until the LIL is proven reliable. To ensure an appropriate balance of cost and reliability in this matter, Hydro will undertake necessary preventive and corrective maintenance work to ensure Hardwoods GT remains available to the Island Interconnected System; however, Hydro will re-evaluate the decision to retain all or portions of the assets in service should extensive maintenance or incremental capital expenditures are required to facilitate this life extension.

As discussed in Section 3.3.2, the Stephenville GT is required to remain in service until both the in-service of a power transformer at Bottom Brook Terminal Station and the LIL is proven reliable. As such, it will continue to be available through the next two winter seasons.

7.4 Imports over the Maritime Link

Since the in-service of the Maritime Link, Hydro has been successful in making economic purchases to economically offset the requirement to produce additional thermal energy. In the prior fall and winter operating seasons, from September 2019 through March 2020, 311 GWh was imported over the Maritime Link, offsetting higher cost thermal generation. While all of the market purchases to date have been made on an economic basis, these purchases have also provided system reliability benefits by reducing the requirement to operate Holyrood TGS and standby generation.

For the period from September 2019 through the end of March 2020, Hydro imported power through a combination of monthly agreements, day-ahead commitments, and real-time transactions. During this period, purchased energy was successfully delivered in more than 95% of scheduled hours.

As outlined in Section 6, import scenarios are contemplated as sensitivities to cases considered in this report. Hydro modelled firm imports of 50 MW and 100 MW from December to March in winters before the LIL is placed in service, with an associated FOR intended to serve as 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 would be available. The analysis demonstrates the effect on the system if the capacity was available in the requested amounts.

7.5 Capacity Assistance

Hydro currently has an agreement with CBPP for capacity assistance. The current agreement expires on the earlier of April 30, 2022 or the commissioning of the Muskrat Falls generating plant, ensuring the availability of this agreement to increase system reliability should the LIL be unavailable in either of the 2020–2021 or 2021–2022 winter operating seasons.

Hydro has also engaged Vale to provide capacity assistance from its diesel generators. The current agreement provides 7.6 MW of capacity assistance through the 2020–2021 winter operating season.

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 in the near-term.

To help ensure reliable service for customers in advance of the in-service of the LIL, Hydro has committed to maintaining Holyrood TGS as a generating facility until March 31, 2023. Hydro will inform the Board of any changes to this time frame as we continue to monitor LIL progress and schedules. Hydro also proposes to extend operation of the Hardwoods GT and retire this asset at the same time as the Holyrood TGS.

There is potential to mitigate identified resource shortfalls by entering into contracts for firm capacity over the Maritime Link and renewing capacity assistance agreements, as required. Hydro is working closely with Nalcor’s Power Supply leadership 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 working to complete critical maintenance activities and other high priority work to ensure the reliability of its existing assets and infrastructure in the near-term. Following the full in-service of the Muskrat Falls project assets and the retirement of Holyrood TGS, small values of LOLH and EUE continue to be observed in winter months increasing with retirements and increasing system load; however, values are materially reduced from those observed prior to the in-service of the Muskrat Falls project assets.

Appendix A

Assessment of Requirements to Enable Short-Term Extension of Holyrood Thermal Generating Station

Introduction

As communicated to the Board of Commissioners of Public Utilities ("Board") on September 28, 2020, in light of the Muskrat Falls Project schedule update provided at that time, Hydro has committed to having the Holyrood Thermal Generating Station ("Holyrood TGS") fully available for generation until March 31, 2023. Beyond that date, Unit 3 at the Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be retired and decommissioned.

Prior to the recent announcement of the extension of the Holyrood TGS to 2023, the existing capital and operating and maintenance plans for the Holyrood TGS were developed based on the previously committed March 31, 2022[36] retirement date. The additional capital required as a result of the extension to 2023, as well as consideration of the requirements if there were to be an extension to March 31, 2024,[37] is outlined in this report. Hydro's capital plan also includes projects for the conversion of Unit 3 to a dedicated synchronous condensing unit[38] and projects required to support synchronous condensing operation into the future. The operating and maintenance plans, likewise, were constructed around the staffing and maintenance required to operate Holyrood TGS as a fully capable generating facility until March 31, 2022 and a single unit synchronous condensing facility beyond that date. These plans are being updated for the extended operation to March 31, 2023.

This report does not outline any capital which may be required related to Hydro's assessment of options to improve the suitability of the Holyrood TGS as a back-up facility. Whether the Holyrood TGS should be considered as a long-term resource option will be informed by the outcomes of Hydro's ongoing Assessment of Labrador-Island Link Reliability Considering Climatological Loads. At that time, Hydro will determine whether it is necessary to undertake a full condition assessment of the Holyrood TGS.

Capital & Operating Requirements

Hydro has committed to have all three Holyrood TGS units fully available for generation, whether online in generation mode or in standby mode until March 31, 2023. When operating in hot standby mode, units must be able to be recalled from standby to provide generation to the grid within four to eight hours. Hydro expects that when online, the units will be required to operate anywhere in the range from minimum loading to full capability, depending on system requirements.

[36] Extension of Holyrood Thermal Generation Station as a Generating Facility, February 14, 2020.
[37] As requested by the Board in its correspondence of October 8, 2020.
[38] Any extension of steam operation will result in deferral of these projects to the appropriate time frame.

The following provides information on required capital execution, supplemental capital plans, and operations and maintenance ("O&M") activities including projected budgets and environmental considerations.

Capital Work

Capital work currently identified, as well as that required to support the extension of the Holyrood TGS to 2023, and the 2024 scenario proposed by the Board, is detailed in Tables A-1 through A-5. The capital has been categorized using three general classifications of projects:

- Type 1: Sustaining capital work that is not dependent on end of steam operation; [39]
- Type 2: Capital work required to repurpose Holyrood TGS from a three-unit generating facility to a single-unit synchronous condensing plant;[40] and
- Type 3: Identified capital work required for safe and reliable operation of the steam generating equipment until March 31, 2023 and potentially to March 31, 2024, if required.

Table A-1: 2021, 2022 and 2023 Capital Projects from Current Capital Plan (Types 1 and 2 - Sustaining and Repurposing Projects)

Year	Project[41,42]	Classification
2021	Overhaul Unit 3 Generator	Type 1
	Upgrade Waste Water Equalization System	Type 1
	Upgrade Distributed Control System Hardware	Type 1
	Inspect Chemical Tanks	Type 1
	Thermal In Service Failures	Type 1
2022	Condition Assessment of Air Receivers[43]	Type 1
	Upgrade Biogreen Sewage System	Type 1
	Replace Fire Water Distribution System	Type 1
	Thermal In Service Failures	Type 1
	Upgrade 600V VFDS in Waste Water Treatment Plant	Type 1
	Install Energy Efficient High Bay Lighting	Type 1
	Replace Generator Components Unit 3	Type 1
2023	Refurbish Stage II Cooling Water Pumphouse	Type 2
	Thermal In Service Failures	Type 1
	Inspect and Upgrade Light Oil System	Type 2
	Install New Oil Systems Unit 3	Type 2
	Replace Stage I 4160 VAC Breakers	Type 2
	Replace Stage II Electrical Distribution Equipment	Type 2

[39] There is no change from the current plan for these projects.
[40] Type 2 projects have shifted by one year to reflect the extension of the Holyrood TGS to March 31, 2023. The exception being the Refurbish Stage II Cooling Water Pumphouse which remained in 2023 as it contains elements of both Type 1 and 2.
[41] Projects listed may differ from Hydro's submitted 2021 Capital Budget Application five-year capital plan due to additional planning and scheduling changes recently undertaken as a result of the extension of the Holyrood TGS to March 21, 2023 as submitted to the Board on September 28, 2020.
[42] The justification for additional civil infrastructure projects is currently being assessed for potential inclusion in Hydro's 2022 Capital Budget Application submission.
[43] The 2021 CBA five-year plan identified this project as a replacement of an air receiver. The scope has since been updated to reflect a condition assessment of the air receivers.

The list of projects outlined in Table A-1 assumes that Hydro will be successful in extending environmental certification of bunker storage tanks 2, 3 and 4. As outlined in Hydro's 2021 Capital Budget Application, Hydro is currently working with the environmental regulator, the provincial Department of Environment, Climate Change and Municipalities, on this extension. As the Labrador-Island Link is brought online and placed in service, production at the Holyrood TGS is expected to be substantially lower than in the recent past and three bunker storage tanks are anticipated to be sufficient to support the continued operation of Holyrood TGS in generation mode until March 31, 2023. Bunker storage tank 1 is not suitable for continued operation past 2021.

Projects required to enable extension of the Holyrood TGS in generation mode until 2023 and 2024 (Type 3 capital) are included in Tables A-2 to A-5. Several of these projects are high cost, long cycle overhauls on turbine and generator equipment that are set to occur near the end of steam generation. Timing of these overhauls is based on technical recommendations and operational experience, and they have been proven to enable safe, reliable operation. The timing of the in-service of the Muskrat Falls assets and the execution of the proposed steam generation related capital projects presents a unique circumstance. Top of mind is the importance of balancing cost and reliability. Hydro will continue to carefully monitor the integration and in-service of the Muskrat Falls Assets and will give careful consideration to the necessity of executing the full scope of steam generation related capital projects. Where there is opportunity to mitigate some portion of capital costs, Hydro will ensure prudency in its capital expenditures.

Table A-2: Projects Included in 2021 Capital Budget Application Required for Extended Holyrood TGS Generation Capability (Type 3)[44]

Item	Project	Estimate ($)	Year	Comments
1	Overhaul Unit 3 Boiler Feed Pump East	373,000	2021	Six-year scheduled overhaul. This was originally scheduled for 2020, deferred based on condition.
2	Boiler Condition Assessment and Miscellaneous Upgrades	3,000,000	2021	This will be required for each year of extension. This project entails detailed inspection, refurbishment and replacement of critical boiler pressure components and is a must do from a safety perspective.
3	Overhaul Unit 1 Turbine and Valves	8,026,600	2021	Nine-year scheduled overhaul. This nine-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global and AMEC. Consistent with industry practice.
	Total	**11,399,600**		

Table A-3: Projects Under Consideration for 2021 Execution Related to the Extension of the Holyrood TGS Generation Capability (Type 3) to March 31, 2023[45]

Item	Project	Estimate ($)	Year	Comments
1	Overhaul Unit 1 Boiler Feed Pump East	350,000	2021	Six-year scheduled overhaul. Last completed in 2015 and due to be completed in 2021.
	Total	**350,000**		

Table A-4: Projects Under Consideration for 2022 Execution Related to the Extension of the Holyrood TGS Generation Capability (Type 3) to March 31, 2023

Item	Project	Estimate ($)	Year	Comments
1	Boiler Condition Assessment and Miscellaneous Upgrades	3,000,000	2022	This will be required for each year of extension. This project entails detailed inspection, refurbishment and replacement of critical boiler pressure components and is a must do from a safety perspective.
2	Turbine Valve Overhaul Unit 3	3,400,000	2022	Three-year scheduled overhaul. This three-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global and AMEC. Consistent with industry practice.
3	Major Pumps Overhaul U1CWPWest, U3CWPEast, U1VPNorth, U1BFPWest	700,000	2022	Six-year scheduled overhaul on Unit 1 Boiler Feed Pump West. Last completed in 2016 and due to be completed in 2022. Two cooling water pumps and a vacuum pump also due for overhaul (12 year interval).
	Total	**7,100,000**		

[44] At the time of the 2021 CBA, the proposed retirement date for the Holyrood TGS was March 31, 2022.
[45] Under consideration for potential supplemental capital application with planned execution in 2021, subject to Board approval.

Table A-5: Additional Projects Anticipated Should Holyrood TGS Generation Capability Extend (Type 3) to March 31, 2024[46]

Item	Project	Estimate ($)	Year	Comments
1	Upgrade UPS 1 and 2	350,000	2022	Recommended to complete this upgrade in 2022 if operation is extended to 2024. UPS 3&4 Replaced in 2020/2021. UPS 1&2 are also obsolete and should be replaced to ensure reliable operation and availability of parts and support.
2	Upgrade Mark V Turbine Governor System Unit 1 and Unit 2	1,500,000	2022	Recommended to complete this upgrade in 2022 if operation is extended to 2024. System is obsolete. Parts not available and support difficult to find. Upgrade to Mark VIe utilizes same cabinets and is cost effective approach to ensure reliability.
3	Upgrade Turbine Supervisory System	75,000	2022	Recommended to complete this upgrade in 2022 if operation is extended to 2024.
4	Boiler Condition Assessment and Misc. Upgrades	3,000,000	2023	This will be required for each year of extension. This project entails detailed inspection, refurbishment and replacement of critical boiler pressure components and is a must do from a safety perspective.
5	Overhaul Unit 2 Turbine and Valves	6,800,000	2023	Nine-year scheduled overhaul. This nine-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global and AMEC. Consistent with industry practice. This project will be assessed for optimization in 2021 and adjusted if appropriate.
6	Major Pumps Overhaul U2CWPWest, U2BFPWest	500,000	2023	Six-year scheduled overhaul on Unit 2 Boiler Feed Pump West. Last completed in 2017 and due to be completed in 2023. Unit 2 cooling water pump west also due for overhaul (12-year interval)
7	Upgrade Day Tank	2,000,000	2023	The fuel oil day tank is due for internal inspection in 2023. However, this may not be required as there is an opportunity to extend this beyond 2024 in compliance with the applicable codes and based on engineering judgement. Work to defer the inspection is kicking off in November 2020.
8	Marine Terminal and Fuel Delivery Piping Condition Assessment	200,000	2023	Updated Level 2 condition assessment should be completed for operation beyond 2023.
	Total	**14,425,000**		

[46] Further study required in 2021 to confirm and optimize.

Extension Impact on Operating and Maintenance Plans

The current annual operating budget for Holyrood TGS is $24 million. Under current plan, it is expected that this budget would remain similar for 2021 and 2022, with a slight reduction in System Equipment and Maintenance ("SEM") costs due to the pending end of steam generation. In 2023 and beyond, the annual operating budget is expected to be considerably lower due to the anticipated transition to post-steam operations and the associated reduction in staffing and maintenance requirements.

If the plant operation were to be extended to 2024, it is expected the O&M budget for 2022 and 2023 would be similar to 2020. There is potential for reductions commencing in 2022, pending reduction of energy output needs from the steam generating assets. Associated human resource plans, service contracts and fuel contracts would need to be extended, typical of 2020.

Finally, Holyrood TGS operates under an Environmental Certificate of Approval to Operate, issued by the provincial Department of Environment, Climate Change and Municipalities, with the current certificate of approval to operate expiring in August 2021. A new or revised certificate is required to operate beyond August 2021. An application for extension will be submitted in the spring of 2021.