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May 22, 2018

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Near-Term Generation Adequacy Report – May 2018

Further to the Board's 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 one original (1) plus twelve (12) copies of Newfoundland and Labrador Hydro's report entitled "Near-Term Generation Adequacy Report".

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael S. Ladha
Legal Counsel and Assistant Corporate Secretary
MSL/skc

Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Danny Dumaresque

ecc: Denis Fleming – Cox & Palmer
Roberta Frampton Benefiel – Grand Riverkeeper® Labrador
Larry Bartlett – Teck Resources Ltd.

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVID R. GOOSNEY SIGNATURE May 22, 2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Near-term Generation Adequacy Report

May 22, 2018

A Report to the Board of Commissioners of Public Utilities

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Executive Summary

Hydro has conducted an assessment of its overall asset health and a subsequent risk assessment of its ability to meet Island Interconnected System (IIS) energy and demand requirements through Winter 2021-2022. Hydro's analysis considers a range of forecast scenarios and varying levels of equipment availability.

The 2018 in-service of the Labrador-Island Link, combined with Recapture Energy and contracted supply from external markets, ensure Hydro is well positioned to reliably supply customers.

Further, while access to markets via the Maritime Link also bolsters system reliability, it has not been included in this analysis given the conservative focus of this report. Through 2018, Hydro has been successful in using the Maritime Link to both reduce thermal generation at Holyrood and avoid gas turbine production.

Hydro's asset reliability, energy in storage, and forecast load have all been contemplated in the development of this report, with appropriate sensitivities modeled as required. To support this analysis, Hydro has conducted a thorough assessment of its assets and the potential risks to the reliable operation of key generation assets, reflected in the projections of availability metrics based on historical data and the anticipated impact of planned improvements.

For Hydro's anticipated supply case, including sensitivity assessments on the same, the reserve margin remains in excess of 21% with no violations of Expected Unserved Energy or Loss of Load Hours observed in the study period.

Hydro recognizes that, at times, there are asset and system conditions that cause customers concern and require a focused effort to ensure adequate supply is available. In the event of any generation or transmission issue, short or long in duration, Hydro works to resolve the issue with urgency to ensure all generation and transmission is available to meet system requirements, inclusive of reserve.

Hydro has taken actions to address repeated issues including broader reviews that frequently involved external experts; addressing issues with improved urgency; and an increased focus on asset reliability, as presented in this report. These actions are expected to enable continued reliable service this coming winter and in near-term operating seasons.

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Appendices

1 Introduction

The "*Near-Term Generation Adequacy Report*" addresses Hydro's capability to provide adequate supply to its Island Interconnected System (IIS) customers by meeting peak demand and energy requirements. This report is filed semi-annually, on May 15 and November 15 of each year, through interconnection with Labrador and the Maritimes. Hydro's previous assessment was filed with the Public Utilities Board (the Board) on November 15, 2017.

2 Island Interconnected System Overview

Hydro is the primary generator of electricity in Newfoundland and Labrador. Hydro's statutory mandate is provided in subsection 5(1) of the Hydro Corporation Act, 2007 as follows:

> *The objects of the corporation are to develop and purchase power on an economic and efficient basis … and to supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province…*

The Company's transmission, distribution, and customer service activities include the operation and maintenance of over 3,500 kilometers of transmission lines and 3,400 kilometers of distribution lines. Hydro serves one large utility customer, Newfoundland Power, five regulated industrial customers, and over 38,000 direct residential and commercial customers.

Hydro's current service areas include: the IIS; the Labrador Interconnected System; the L'Anse au Loup System; and isolated diesel communities in Labrador and on the Island. The primary focus of this report is the IIS.

2.1 Generation and Transmission Infrastructure – Current State

The IIS is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula and bulk 230 kV transmission lines extending from Stephenville in the west to St. John's in the east. Currently, the two largest sources of generation on the Island are Bay d'Espoir, a hydraulic plant on the south coast of the island; and the Holyrood Thermal Generating Station, a large oil-fired thermal generating plant; located on the Avalon Peninsula.

Since the filing of Hydro's previous Near-term Generation Adequacy report in November 2017, there have been two important changes to the IIS. The first is the in-service of a third 230 kV transmission line, TL 267, between the Bay d'Espoir and Western Avalon terminal stations. TL 267 has increased Hydro's capability to deliver power to the major load centre on the Avalon Peninsula, eliminating the major transmission constraints on the IIS. The second is the completion of the Maritime Link (ML). The ML is a high voltage DC line connecting the island of Newfoundland and Nova Scotia, providing the first interconnection of the IIS to the North American Grid. To date, Hydro has made market purchases over the ML totalling 24 GWh, which have reduced Hydro's use of thermal generation at Holyrood and gas turbine production.

2.2 Generation and Transmission Infrastructure – Future State

Work is currently underway on the construction and integration of the Muskrat Falls Project Assets. The Muskrat Falls Project includes an 824 megawatt hydroelectric generating facility at Muskrat Falls and the Labrador-Island Link (LIL) that will transmit power from Muskrat Falls to Soldiers Pond on the Avalon Peninsula. The LIL will provide the IIS with a second interconnection to the North American Grid and provide the IIS with access to recapture energy in excess of Labrador Interconnected System requirements. The LIL is expected to be in service in Q3 of 2018 and will be available for the 2018-2019 winter peak.

Figure 1 presents a visual overview of Hydro's generation and transmission infrastructure following the completion of Muskrat Falls Project and the LIL.

Figure 1: Hydro's Generation and Transmission Infrastructure

3 System Planning Criteria

3.1 Load Forecasting

Hydro continues to base its generation supply planning decisions on a P90 peak demand forecast.[1,2] The P90 peak demand forecast results from instances of more severe wind and/or colder temperatures, reflecting an associated increase in demand over a normalized, or P50 peak demand forecast.[3] The development of the P90 peak demand forecast is an extension of Hydro's regularly prepared system operating load forecast.

Both P50 and P90 peak demand forecasts are important measures for Hydro when assessing system adequacy. The P50 forecast is the basis for the system operating load forecast[4] and development of Hydro's energy forecast, while the P90 forecast is the basis for Hydro to assess its ability to reliably supply customers in instances of severe weather conditions. Given the conservative analysis included in this report, the P90 peak demand forecast is appropriate.

3.2 Generation Planning Criteria

Hydro has established generation planning criteria for the IIS that determines the timing of generation source additions to meet customer demand. These criteria set the minimum level of capacity and energy installed on the IIS to ensure an adequate supply for firm demand. Hydro's Loss of Load Hours (LOLH)[5] and firm energy criteria have been in use for more than 35 years and in that period have been reviewed several times, most recently by Manitoba Hydro Incorporated, Ventyx, and Liberty Consulting. In addition, Hydro has adopted a reserve margin

[1] A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time. A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time, i.e. the average forecast.
[2] In accordance with direction in the Board's letter to Hydro regarding Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - "Directions further to the Board's Phase One Report", received October 13, 2016.
[3] Hydro requires a weather normalized load forecast from which to plan and operate the IIS. This load forecast can also be referred to as an "average forecast" or a P50 forecast.
[4] The operating load forecast reflects expected, or average, system energy requirements across specific time intervals and expected peak demand as part of Hydro's operating load requirements.
[5] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year.

criterion, as discussed in *Hydro's Response to the Phase I Report by Liberty Consulting*.[6] Hydro is currently undertaking a review of its planning criteria for post-interconnection to be presented to the Board in November 2018.

Hydro's current generation planning criteria are as follows:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.[7]
And
The Island Interconnected System should have sufficient generating capacity to maintain a minimum reserve of 240 MW at the P90 system peak.[8]

Energy: The Island Interconnected System should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability.[9]

3.3 Transmission Planning Criteria

The transmission system on the island of Newfoundland is assessed and expanded based upon prescribed transmission planning criteria. The transmission planning criteria used by Hydro, and reviewed by the Board, are defined as follows:

1. In the event a transmission element is out of service (i.e. under n-1 operation), power flow in all other elements of the power system should be at or below normal rating;

[6] http://pub.nl.ca/applications/IslandInterconnectedSystem/files/corresp/NLH-Phase-I-Reply-Submission-re-Liberty-Group-Report-2015-02-06.pdf.
[7] For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in an average year.
[8] The 240 MW reserve margin provides Hydro with the ability to withstand the most onerous single contingency (loss of Holyrood Unit 1 or 2) while maintaining an additional reserve of 70 MW.
[9] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Thermal Generating Station) is based on energy capability adjusted for maintenance and forced outages.

2. For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105%; and
3. For contingency or emergency situations, voltages between 90% and 110% are considered acceptable.

3.4 Combined Generation and Transmission Planning Outlook

Currently, Hydro uses LOLH, reserve margin, and Expected Unserved Energy (EUE)[10] to assess generation adequacy. Each measure has strengths and limitations and includes some aspects that the others do not. Generally, if there is correlation between the three measures it indicates a robust analysis.

As noted in Section 3.2, Hydro's existing Generation Planning Criteria defines an LOLH target of 2.8 hours per year. In previous risk assessments, the correlation of LOLH and EUE determined that EUE of 300 MWh was approximately equivalent to an LOLH of 2.8. As part of its broader supply adequacy review, Hydro has migrated from using Strategist to the PLEXOS (Plexos) modelling platform. Plexos is capable of embedding consideration of the transmission network when evaluating system adequacy. Plexos is used heavily in the utility industry, and is also used by other Atlantic Canadian utilities. While the results of the new model are consistent with those calculated in previous Near-term Generation Adequacy reports, the equivalency point for EUE and LOLH for the existing IIS has shifted with EUE of 170 MWh now approximating Hydro's current planning criteria LOLH of 2.8. This will result in increased conservatism as Hydro continues to evaluate and plan for its ability to maintain acceptable supply adequacy. For more discussion of the changes to the modelling approach, please refer to Section 6.3.

Note that both LOLH and EUE are probabilistic assessments of system adequacy. These metrics provide an indication of the level of supply risk for the system. Results in excess of the

[10] Expected Unserved Energy (EUE) is a statistical prediction of the amount of load that is unable to be served due to a shortfall in either generation or transmission capacity. When compared to LOLH, EUE provides a better measure of the magnitude of outages rather than the frequency of outages.

expressed thresholds indicate an increased likelihood, but no guarantee, of loss of supply outside of the utility's accepted risk profile. Further, assessments of EUE or LOLH that indicate no violation of planning criteria do not mean that there is no risk of loss of load, but rather that the risk is within acceptable system limits.

For further discussions of results, please refer to Section 6.4.

4 Asset Reliability

On a quarterly basis, Hydro reports to the Board on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b) the assumptions used in System Planning's assessment of generation adequacy (Hydro's "*Rolling 12 Month Performance of Hydro's Generating Units*" report). The most recent report was submitted on April 30, 2018, for the quarter ending March 31, 2018. These reports detail any unit reliability issues experienced in the previous 12-month period and compare performance on a year-over-year basis.

Hydro continues to take actions to address repeated issues including broader reviews that frequently involve external experts; addressing issues with increased urgency; and 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.

4.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since its most recent "*Near-Term Generation Adequacy Report"*, filed on November 15, 2017. This report provides updates on items as required and discusses additional items that may impact asset performance. The intention is to ensure issues affecting reliability have been appropriately addressed. Issues that are recurring in nature, if not managed properly, can have a significant impact on unit reliability. As such, they require an additional level of review and mitigation to ensure improved asset reliability. The discussion provided in Sections 4.1.1through 4.1.3provides 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 considered in the selection of appropriate Deration Adjusted Forced Outage Rate (DAFOR) and Derated Adjusted Utilization Forced Outage Probability (DAUFOP)/Utilization Forced Outage Probability (UFOP).

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 actions taken to mitigate against future reliability impacts. The scope is not limited to Hydro's assets (i.e., penstock, boiler tubes), but also considers environmental challenges facing Hydro's operations, such as lower than average inflows.

As part of this exercise, Hydro has identified the following areas of discussion, grouped by facility type:

1. Hydraulic: Bay d'Espoir penstocks, lightning, frazil ice, Upper Salmon rotor key cracking, Hinds Lake bearing coolers, and Cat Arm Spherical Valve Controls;
2. Thermal: Unit boiler tubes, variable frequency drives, air flow limitations due to normal boiler fouling during operating season, turbine control system, exciter controls, Unit 2 steam inlet flange, Unit 1 boiler stop valve, and Unit 1 and Unit 2 hydraulic fluid condition; and
3. Gas Turbines: End A engine unavailability at Stephenville, automatic voltage regulator at Hardwoods, stack issues at Hardwoods and Stephenville, and combustion can failures at Hardwoods.

4.1.1 Hydraulic

4.1.1.1 Bay d'Espoir Penstocks

In its November 2017 *"Near-Term Generation Adequacy Report"*, Hydro detailed the significant work undertaken in 2016 and 2017 to address deteriorated welds in Penstocks 1 and 2 at Bay d'Espoir. Further analysis by a third-party consultant, Hatch, determined that the condition was materially attributable to turbine rough zone operation, not previously understood to adversely affect penstock health, combined with the methodology used in the original construction of the Bay d'Espoir Penstocks. A report on analysis of Bay d'Espoir Penstock 1 has recently been filed with the Board and a Supplemental Capital Budget Application to complete Level 2 condition assessments on Penstocks 1, 2, and 3 is forthcoming.

In May 2018, non-destructive testing confirmed cracks in Bay d'Espoir Penstock 3.[11] Hydro continues to investigate the extent of the cracking, and has commenced a project to refurbish the areas affected by cracking using the Allowance for Unforeseen Items Account. This Penstock is planned to be returned to service this summer and Hydro will keep the Board informed on this project.

Hydro has revised its preventive maintenance program for penstock inspections to reduce the risk of future events. The five-year inspection frequency has been re-established for steel penstocks, completed by external consultant specialists. Hydro has developed plans to inspect and refurbish other penstocks in the fleet, on a priority basis, with the expanded scope of inspection. Inspections of Penstock 4 at Bay d'Espoir and at Hinds Lake were completed in 2016, with no concerns identified. Hydro plans to complete penstock inspections at Upper Salmon, Cat Arm, and Paradise River in 2018; Snook's Arm in 2019; and Granite Canal in 2020. Inspection frequency and scope currently planned may evolve depending on recommendations stemming from the Level 2 Condition Assessments planned to be completed at Bay d'Espoir this year, as well as the findings from the root cause analysis on Penstock 1.

4.1.1.2 Lightning

Some of Hydro's generating units connected to the IIS via radial transmission lines [e.g., Cat Arm (127 MW), Hinds Lake (75MW) and Paradise River (8 MW)] are susceptible to tripping during lightning strikes to the transmission lines. While lightning is not considered to have a

[11] Visual inspection completed in April 2017 provided no indication of cracks in Penstock 3.

significant impact on unit reliability on an individual unit basis, Hydro continually assesses the impact of lightning on all units to determine if additional measures are possible and warranted to improve system reliability.

When a strike does result in a plant trip, there can be exposure for an underfrequency event on the IIS. Hydro is actively working to reduce the risk of such an event and improve reliability for customers by changing its operating practice.[12] This change in practice has helped Hydro better manage the IIS during lightning events resulting in a positive impact on customers' reliability by avoiding a number of underfrequency events.

In addition, with TL 269 in service in 2017, an alternate connection to Granite Canal and Upper Salmon exists, reducing the risk of loss of supply due to a lightning event for these plants.

4.1.1.3 Frazil Ice

Hydro has undertaken a number of improvements in detection systems and operational procedures to mitigate unit unavailability resultant from frazil icing conditions.[13,14] Energy Control Centre (ECC) Operators continue to proactively manage frazil icing risk by closely monitoring environmental conditions,[15] responding to trashrack differential alarms, and

[12] Energy Control Centre (ECC) operators use the real-time Lightning Tracking System application to monitor lightning activity near Hydro's transmission systems and generating stations. In instances where lightning is approaching a station or its connecting transmission line, the ECC operators will, wherever possible, take action to reduce the overall loading on the plant to a level below which would require underfrequency load shedding if a trip were to occur (typically 50 MW or less).

[13] Frazil ice is soft or amorphous ice formed by the accumulation of ice crystals in water that is too turbulent to freeze solid. This type of ice accumulates at plant intakes limiting the area in which water can pass through, impacting the amount of water that can be drawn into the plant, and thereby reducing the generating unit capability.

[14] Hydro's November 2017 *"Near-Term Generation Adequacy Report"* detailed a number of such improvements including: (1) the replacement of water temperature sensors with more accurate devices enabling operators to better respond to frazil icing situations by making dispatch changes; (2) the optimization of trashrack differential alarm settings at plants known to have increased likelihood of frazil icing, increasing awareness of frazil ice levels, thereby providing the opportunity to de-ice the trashrack and avoid an extended outage of several days; and (3) the development of guidelines for preventive flow reduction at Upper Salmon and Granite Canal to prevent the formation of frazil ice.

[15] Environmental conditions include ice cover, water temperature, and wind speed.

optimizing unit dispatch to allow solid ice cover to form. In the 2017-2018 winter operating season Hydro experienced one outage due to frazil ice.[16]

Improvements to the frazil ice management system planned for 2018 include the installation of a system to remotely activate the frazil ice bubbler at Granite Canal. Remote operation will reduce downtime and labour costs as, currently, operators must travel to site to activate the bubbler.

4.1.1.4 Upper Salmon Rotor Key Cracking

In Hydro's November 2017 *"Near-Term Generation Adequacy Report,"* Hydro detailed the continued observation of cracked rotor key welds on the generating unit at Upper Salmon plant, attributed to fretting corrosion.[17] To address this risk, in consultation with an Original Equipment Manufacturer (OEM) engineer, Hydro has scheduled and conducted monthly inspections of rim key welds. These inspections have continued to identify cracked welds through 2018, with repairs undertaken upon identification. Hydro's 2018 capital plan includes an upgrade to the spider rim guidance system to address this issue.

4.1.1.5 Hinds Lake Bearing Coolers

Hydro's November 2017 *"Near-Term Generation Adequacy Report"* noted that three of the six bearing coolers at Hinds Lake plant required replacement. At the time, to mitigate the risk to the 2017-2018 winter operating season, Hydro repaired leaks in existing coolers and purchased an external cooler/filter that can provide the equivalent cooling capacity of two coolers. No cooler leaks were experienced in the 2017-2018 winter operating season.

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[16] On December 27, 2017, the Upper Salmon unit was forced offline due to rapidly developing frazil ice. At 8:30 AM on the morning of December 27, 2017, ice buildup was noted on the trash racks and by 9:00 AM the unit was proactively taken offline to protect the unit. The ice was cleared using divers and the bubbler system and the unit was restored to service in approximately 56 hours.

[17] Fretting corrosion is a form of accelerated atmospheric oxidation that occurs at the interface of contact materials undergoing slight repeated movement. One of the most common causes of loss of structural integrity is the development and propagation of cracks. Fretting corrosion in the case of floating rims, can lead to cracks. If a key moves fully out of its slot, there is potential for the key to fall between the rotor poles and the generator stator which could result in catastrophic failure.

A full set of coolers are currently on-site enabling Hydro to replace affected coolers as part of the 2018 annual outage for this unit.

4.1.1.6 Cat Arm Spherical Valve Controls

Hydro's November 2017 Near-term Generation Adequacy report noted that an upgrade of the spherical valve controls in Cat Arm is required due to existing potential for valve malfunction during unit trips in the current system.[18] Hydro's risk mitigation plan for these units is as follows:

1. Hydro has proactively scheduled valve exercising when units are offline to ensure proper functionality until the controls are replaced; and,
2. As part of the units' 2018 annual maintenance outage, the spherical valve controls will be replaced on both units in Cat Arm. Note that this issue has not resulted in any reliability issues to-date and is expected to be resolved once the capital project is complete. Hydro will continue to monitor to ensure this risk is resolved.

4.1.2 Thermal

4.1.2.1 Unit Boiler Tubes

Each of the three thermal generating units at the Holyrood Thermal Generating Station (HTGS) has a boiler that contains tubes. Due to the failure of some tubes and thinning walls in others, Hydro experienced both unit outages and unit deratings in Winter 2015-2016. Affected tubes were replaced during annual planned unit outages in 2016, prior to the 2016-2017 winter season. There have been no boiler tube related outages or deratings since the reheater tube failures in January and February of 2016. Hydro continues to monitor this situation.

[18] The primary risk occurs when the plant is not staffed during a trip. At the extreme, this could result in flooding on the lower levels of the plant.

4.1.2.2 Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at HTGS. The Variable Frequency Drives (VFDs) were installed to vary the amount of air required based on generation need, thus reducing auxiliary power requirements and resulting in fuel savings.

Previous to Winter 2016-2017 there had been operational issues with the VFDs resulting in unit trips and reduced unit output. Throughout 2016, Hydro worked closely with Siemens, the OEM, to resolve the issues and improve the reliability of these drives. As a result, multiple aspects of the VFDs were modified and additional actions were taken to improve reliability. This appeared to be effective for a period of time as the VFDs operated reliably throughout the 2016-2017 operating season.

Hydro continued to work with Siemens in 2017 and completed preventive maintenance on all the drives during the annual outages. Hydro also implemented a spare part cycling strategy to reduce the likelihood of shelf-life failures by rotating spare parts through the operating equipment. Despite this work, reliability issues with the drives were experienced during the 2017-2018 operating season.[19] Hydro continues to ensure readiness to respond, as well as continues to have spares available, while additional options are considered for reliable operation of the affected systems.

4.1.2.3 Air Flow Limitations

Appropriate air flow is required to provide enough air for combustion, enabling units to provide full output. HTGS Units have experienced air flow limitations since 2015. Deratings have resulted from fouling of the air heaters and boiler sections, including the economizer, and from air heater leakage. Fouling and air heater leakage has led to the inability of the boiler fans to

[19] On February 17, 2018 there was a failure of the Unit 3 east cabinet cooling fan that caused a forced derating to 50 MW for approximately one hour while the fan was replaced. On March 19, 2018 the west VFD on Unit 1 tripped due to a failure of a power cell. On March 26, 2018 the east VFD on Unit 1 tripped due to a failure of a power cell.

provide sufficient air flow for operation at high loads. Also, fouling has caused a back pressure in the furnace that increases with load, which can result in requirements to limit load.

Over the last several years, while Hydro has experienced temporary relief in some instances, limitations on unit capacity re-develop. In December 2017, Hydro engaged boiler OEM B&W and an external consultant to complete an engineering study of the issues and provide new recommendations for consideration and resolution. The results of this study have shown that the three primary causes of boiler derating are:

1. Air heater fouling in all units;
2. Air heater leakage in Unit 3[20]; and
3. Economizer fouling in Unit 1 and Unit 2[21].

B&W also observed that the decline in unit performance is due to the impact of discontinuing the use of fuel additive, a decision which occurred in 2014 and was based on the improved fuel oil supply specification. Hydro deemed the cost of supplying this additive was no longer required since the quantities of vanadium and other metals in the fuel had dropped to near zero. The impact on fouling at the air heaters was not known. Fuel additive will be reinstated before the 2018-2019 operating season.

Based on the results of the engineering study, a Supplemental Capital Budget Application is being prepared to replace air heater baskets in all units and correct the air heater leakage in Unit 3 to significantly improve unit capabilities. In parallel, a plan to chemically wash the economizers is planned to correct the economizer fouling issue in Unit 1 and Unit 2. Pending approval, this work will be completed during the planned 2018 annual outages. The fuel additive system is being reinstated and will be operational on all three units prior to return to service in the fall.

[20] Unit 1 and Unit 2 air heater leakage was addressed in 2017.
[21] Unit 3 has a different design economizer that is not prone to excessive fouling.

4.1.2.4 Turbine Control System (Mark V System)

There was one issue related to the Mark V Turbine Control System during the 2017-2018 operating season. When Unit 1 was returned to service in February 2018 following an outage to replace the boiler stop valve, the Operators could not perform an online test of the reheat stop valves. A fuse and board in the Mark V system had failed. A troubleshooting exercise identified the problem as being seized solenoids at the stop valves. These solenoids were replaced along with the failed components in the Mark V cabinet. Hydro continues to work with GE to bolster reliability of the Mark V system. In January 2018, GE delivered on site training for the Instrumentation staff on the Mark V system. Hydro continues to monitor this issue.

4.1.2.5 Exciter control systems

Each generating unit at HTGS has an excitation system that controls the unit output voltage, which contributes to maintaining an acceptable IIS voltage. The exciter consists of a control section, a power section, and a field breaker. These sections can be modified or replaced separately. The exciters for Unit 1 and Unit 2 were installed in 2000 and 1999, respectively. The Unit 3 exciter, installed in 1979 was replaced in 2013 with an Asea Brown Boveri (ABB) Unitrol 6080 system.

To ensure reliable operation of the units, the control sections of the exciters were replaced with the modern Unitrol 6080 equipment. There have been no further reliability issues since the exciters have been upgraded. Hydro continues to monitor this situation and considers this issue to be resolved.

4.1.2.6 Unit 2 Steam Inlet Flange

A flange on the steam piping allows for the piping to be separated when removing the upper half of the turbine shell during major turbine overhauls. Since 2014, there have been repeated steam leaks at this flange.

In December 2016, after the development of a steam leak on Unit 2, the flange was sealed using a temporary compound to ensure reliable operation through the winter operating season to the annual unit outage in 2017, when a permanent fix could be installed. The flange was replaced with a welded solid pipe spool during the 2017 annual outage. The Unit 1 steam inlet flange has not been a recent problem; however there was one flange gasket failure in 2014. A pipe spool is on site for Unit 1 and will be installed during the 2018 outage.

Once replacement is complete on Unit 1, Hydro will continue to monitor the unit; however, it considers the issue resolved.

4.1.2.7 Unit 1 Boiler Stop Valve

On January 20, 2018 the Unit 1 boiler stop valve failed. This valve was the original supplied equipment from 1969. Attempts were made to address the failed valve; however, the attempts were not successful. A modified design to remove the valve and replace it with a spool piece[22] was developed. Hydro consulted Service NL (Boiler regulator), the valve OEM, and the Boiler Contractor. The modified design was approved and on February 21, 2018 the stop valve work was complete and the unit was returned to service.

While the failure resulted in a month of forced outage time for Unit 1, the replacement of the valve with the pipe spool has fully mitigated issues with the Unit 1 boiler stop valve. [23]

4.1.2.8 Unit 1 and Unit 2 Hydraulic Fluid Condition

Hydro has observed contamination in the hydraulic fluid that is used to operate the Unit 1 and Unit 2 turbine valves.[24] The level of fluid contamination required fluid and filter replacement. Samples have been collected for analysis and investigation is ongoing to determine the reason for the contamination.

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[22] A spool piece is essentially a straight piece of pipe.

[23] Note that the Unit 2 and Unit 3 valves are of different design and are much newer than the Unit 1 valve that had failed, and as such, are not anticipated to pose the same risk to those units.

[24] Contamination has been observed through regular sampling. On March 22, 2018, the contamination resulted in a forced outage on Unit 2. On April 3, 2018, Unit 2 was taken offline for repair of the hydraulic ram for the turbine control valves.

As a mitigating measure, flushing is planned for the annual 2018 outage for both units to replace the fluid and clean the systems. Additional work may be identified based on the results of the contamination investigation.

4.1.3 Gas Turbines

Hydro continues to identify, investigate, and resolve reliability issues related to the operation of the Stephenville and Hardwoods gas turbines (GTs). While a number of issues have been resolved since 2014, the age of the units and the use of the units for system support have resulted in additional items for Hydro to identify and manage. Hydro has completed an operation and maintenance review of these facilities with a focus on improving the reliability of these facilities until such time as they are retired or replaced. Details of this review and the progress of implementation were presented to the Board in Hydro's report titled "*Gas Turbine Failure Analysis Recommended Actions Implementation Update,"* filed July 4, 2017 and updated in the Winter Readiness report filed in December 2017. In addition, selected planned capital upgrades to critical systems have been executed to ensure reliable operation of these units until end of life. Finally, in the 2017-2018 winter period, Hydro maintained a second loaner engine to help mitigate risk at the Hardwoods and Stephenville facilities.[25]

The Holyrood Gas Turbine has been operating reliably since it's in-service in 2015. Hydro continues to actively monitor and manage its asset health and, as with any generator on the IIS, Hydro investigates any issue and implements corrective action. Hydro maintains an active service contract with the OEM, helping ensure continued reliable service from this unit.

directed in P.U. 43(2017), Hydro will provide a report to the Board in the 2019 Capital Budget Application regarding the near-term and long-term plans for the Hardwoods and Stephenville gas turbines, including current asset conditions.

[25] Through the 2017-2018 winter operating season Hydro maintained two loaner engines on the island, for a total of six available engines, in the event of an issue with any of the four required engines between Hardwoods and Stephenville.

4.1.3.1 End A Unavailability at Stephenville

On December 27, 2017, Stephenville End A tripped while attempting to switch from synchronous condenser operation to generate mode. The cause of the trip was determined to be an issue with the rear power turbine bearing, which requires the replacement of the bearing. End A was unavailable while a replacement bearing was procured. On December 29, 2017, Hardwoods suffered a failed exhaust bellows. As no spare bellows was available, Hydro used the bellows from Stephenville to return Hardwoods to service as this unit experiences higher usage on the system. Stephenville End A is expected to be returned to service in late July 2018 following the installation of the refurbished bellows and bearing replacement. At this time, it is also expected that this unit will be returned to full capacity with the removal of the 19 MW loaner engine and the installation of the refurbished engine.

4.1.3.2 Automatic Voltage Regulator at Hardwoods

In Hydro's November 2017 "*Near-Term Generation Adequacy Report*," it noted two instances of alternator trips while operating in synchronous condense mode, as a result of system conditions, resultant from misoperation of the Automatic Voltage Regulator (AVR).[26] As planned, the AVR manufacturer's representative completed AVR and exciter training in November 2017. The operation of the AVR was tested, and the unit was returned to service following the completion of the planned maintenance outage.

4.1.3.3 Exhaust Stack Issues Hardwoods and Stephenville

As part of Hydro's November 2017 *"Near-term Generation Adequacy Report,"* exhaust stack cracking issues were observed at both the Hardwoods and Stephenville facilities.[27] The required stack repairs were completed in both Hardwoods and Stephenville in November 2017. No further issues were experienced over the winter operating season. Further repairs are planned

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[26] The AVR had entered a fault state as a result of the trip, which prevented the alternator from automatically synchronizing with the power system. Once the fault was investigated and cleared, the unit was returned to service.

[27] Stack repairs were made on both ends at Stephenville in 2016 as part of the refurbishment program; however, additional cracking had been identified outside the repair area.

on both ends at Hardwoods in 2018 as part of the capital refurbishment project. Hydro will continue to monitor this issue; however, it is considered resolved.

4.1.3.4 Combustion Can Failures at Hardwoods

Two engines installed in Hardwoods experienced combustion can failures in 2017.[28] In both cases, the failure occurred at the location of riveted bands within the combustion can. Both engines were returned to the overhaul facility to have the combustion cans replaced with an upgraded combustion can that is of welded rather than riveted construction. These repairs and upgrades were completed at the overhaul facility and the engines were returned to Hydro.[29] Both engines remain stored awaiting installation and commissioning. The engines were not installed when received due to unit availability requirements during the winter operating season. Planned installation in Stephenville End A is scheduled for July 2018. Hydro continues to monitor combustion can condition through appropriate inspections.

4.2 Selection of Appropriate Performance Ratings

4.2.1 Consideration of Asset Reliability in System Planning

As identified in Section 3, Hydro's asset reliability is a critical component in determining its ability to meet the existing planning criteria for the IIS. As an input to the generation planning process, Hydro uses specific indicators to represent the expected level of availability due to unforeseen circumstances.

In considering its supply adequacy, Hydro evaluated the health of generating units across all asset classes. Table 1 summarizes the projected availability for Hydro's generating assets considered in the assessment of generation adequacy. These projections of asset reliability

[28] In February, Hardwoods engine 202224 failed in service due to a lube oil leak internal to the engine. A borescope inspection completed post-failure also identified an imminent combustion can failure prior to full failure, which in the past has caused material damage to the rest of the engine. In August, a planned borescope inspection of the engine (serial number 202205) identified another combustion can failure.

include appropriate consideration of asset availability and deration (e.g. a short-term deration at Upper Salmon to repair a cracked rotor key).

Table 1: Summarized Asset Reliability Metrics

Asset	Reliability Metric
Bay D'Espoir Hydraulic Units	DAFOR = 3.85%
Remaining Hydraulic Units	DAFOR = 0.73%
Holyrood Thermal Units	DAFOR = 15%,18%,20%
Holyrood GT	DAUFOP = 5%
Stephenville GT	Base DAUFOP = 30% Sensitivity DAUFOP = 50%
Hardwoods GT	Base DAUFOP = 30% Sensitivity DAUFOP = 50%

In determining appropriate reliability metrics for its thermal units, hydraulic units, and standby units, Hydro reviewed: (i) the projected availability noted in its November 2017 "*Near-Term Generation Adequacy Report*;" (ii) experience through the previous winter operating season; (iii) planned 2018 capital and operating programs; and (iv) the projected availability for near-term winter seasons (as discussed in Section 4.1). Analysis was performed with a HTGS DAFOR of 15%, 18%, and 20%, increased from the DAFORs of 14%, 15%, and 20% used in the November 2017 report in consideration of unit performance through Winter 2017-2018. Hydraulic DAFORs and Gas Turbine DAUFOPs[30] remain consistent with those used in Hydro's November report. Hydro continues to consider the DAUFOP indicator for gas turbine reliability, consistent with its approach in the November "*Near Term Generation Adequacy Report.*"[31]

[30] DAUFOP is the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate. Given DAUFOP as an indication of GT reliability would reflect all periods where GT unit deratings impact available system generation, Hydro has decided to use DAUFOP as the basis for all of the analysis in this report.

[31] Hydro has traditionally reported Utilization Forced Outage Probability (UFOP) as the measure of reliability for its gas turbines.

5 Load Forecast

Hydro's peak demand forecast[32] for the Island Interconnected System is comprised of three load components:

- Customer load requirement[33];
- Transmission system load loss requirement[34]; and
- Hydro's generating station service load requirement[35].

As part of this assessment, Hydro has updated both its P50 and P90 peak demand forecasts to reflect the latest available customer and system information. Both Newfoundland Power's and Hydro's forecast load requirements for its retail customers currently indicate stagnant or declining energy requirements across the next five years, consistent with weakness in the provincial economic outlook. [36] However, given the conservative nature of this assessment, Hydro is not assuming the decline in forecasted energy sales translates into decreased demand requirements and, as such, considers utility peak demand requirements that do not decline. Hydro's P90 peak demand forecast, which provides assessment of the peak demand impact of more severe weather conditions, continues to indicate an additional 60 MW in customer coincident over the P50 demand forecast.

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[32] The primary reporting and system planning measure is the megawatt winter peak demand for the island's 60 Hz system.

[33] The customer load requirement component of Hydro's five-year peak demand forecast is developed using forecasted load requirements provided by Newfoundland Power, Hydro's industrial customers, and Hydro's load forecast for its IIS rural service territory. Hydro relies on these inputs to determine a forecast of customer coincident demand for a five-year period. Hydro also prepares longer term system demand forecasts, typically referred to as Planning Load Forecasts (PLF), for the Island Interconnected System that rely on Hydro's internal model of Newfoundland Power's service territory that is based on corresponding provincial economic projections.

[34] Transmission losses are determined by transmission system load flow analysis based on forecast customer coincident demand.

[35] Hydro's station service is the demand and subsequent energy consumed by its generating stations. In the existing Island Interconnected System, the Holyrood generating station is the largest contributor to the IIS station service requirement.

[36] Reflects customer's anticipation of significant retail price increases for electricity, current economic forecasts for the province indicating declines in capital investment in provincial major projects, and a weaker outlook for consumer spending for the next several years.

Hydro's industrial customers have indicated little or no changes from previously provided forecast requirements.

The revised P90 forecast, including the contribution of each of the three components, is provided in Table 2. Information on Hydro's P50 forecast can be found in Appendix A.

Table 2: P90 Peak Demand Forecast[37]

Base Case Winter Demand Forecast				
	P90			
	2018-2019	**2019-2020**	**2020-2021**	**2021-2022**
Customer Coincident Demand (MW)	1718	1718	1716	1716
Transmission Losses (MW)	47	47	47	47
Station Service (MW)	24	24	24	24
Total Island Interconnected System Demand (MW)	**1789**	**1789**	**1787**	**1787**

5.1 Discussion of Hydro's Winter 2017-2018 Peak Demand

Weather conditions that produced peak demands on the IIS for the winter of 2017-2018 were less severe than historically measured P50 conditions. The Island Interconnected System experienced the highest electrical load for the winter of 2017-2018 during the late afternoon on December 27, 2017. As weather conditions on the peak day were less onerous than P50 peak load weather conditions, a lower peak than forecast for utility customers occurred. Owing to the fact that Hydro requested load curtailments of its industrial customers under the current Capacity Assistance arrangements during the core peak hours of that afternoon, load requirements for Hydro's industrial customers were also lower than forecast.

Table 3 At the total IIS customer demand level, the reconstructed coincident demand of 1623 MW was 3% or 52 MW, lower than the P50 forecast of 1675 MW.

provides the summarized actual customer class peak demands for December 27, 2017, the forecast base case coincident customer class demands for the winter peak period and Hydro's

[37] Differences in totals vs addition of individual components are due to rounding.

estimate of a reconstructed peak load.[38] At the total IIS customer demand level, the reconstructed coincident demand of 1623 MW was 3% or 52 MW, lower than the P50 forecast of 1675 MW.

Table 3: Customer Peak Demands - Winter 2016/2017 [39,40]

	P90 Forecast[41]	P50 Forecast[41]	Actual [42]	Reconstructed [43][44]
Utility[45]	1556	1496	1445	1452
Industrial	179	179	118	171
IIS Customer Coincident Demand[46]	**1735**	**1675**	**1563**	**1623**

5.2 Sensitivity Load Growth Scenarios

To ensure a robust assessment of risk, Hydro has considered sensitivity forecasts in addition to the base case forecast. The sensitivity forecasts being considered in this analysis are detailed below:

5.2.1 Sensitivity Load Projection I

No reduction in utility demand from recent years: Assumes that in spite of the current utility forecast, which is for declining energy requirements and reduced demand, demand requirements do not decline but rather remain on par with recent history (i.e. reduced and declining load factor).

[38] The reconstructed peak demand includes the estimated industrial load that was curtailed during the peak period but does not include an adjustment for P50 weather. The P50 weather is estimated at +20 megawatts.

[39] The actual utility demand at peak of 1445 MW was approximately 50 MW lower than the P50 forecast and over 100 MW lower than the P90 forecast. Based on historical weather records tracked by Hydro, the wind chill leading up to the peak period were about 3.5°C warmer than average peak wind chill conditions. Based on Hydro's peak demand weather records, the temperatures leading up to the peak period that contributed to the wind chill conditions were warmer than average while the wind speeds leading up to the peak period that contributed to the wind chill conditions were higher than average.

[40] The reconstructed industrial demand at peak of 171 MW was lower than forecast, resulting from lower than forecast demand at peak for Vale that more than offset a higher than forecast demand at peak for Corner Brook Pulp and Paper.

[41] Forecast as per Hydro's *"Near-Term Generation Adequacy Report"* filed November 15, 2017.

[42] Actual peak occurred between 4:30 and 4:45pm on December 27, 2017.

[43] Reconstructed peak projected to have occurred between 5:00pm and 5:00pm on December 27, 2017.

[44] Industrial reconstructed MW assumes customers at pre-curtailment demand level.

[45] IIS coincident demand of Newfoundland Power and Hydro Rural.

[46] IIS customer coincident demand excluding transmission losses and station service.

5.2.2 Sensitivity Load Projection II

High customer coincidence at peak: Includes increased industrial and utility load requirement over Hydro's base case expectation assuming less diversity in customer demand requirements at Island Interconnected System peak. This sensitivity combines the risks of sensitivity load projections II and III from the previous Near-term Generation Adequacy analysis.

5.2.3 Sensitivity Load Projection III

Assessed customer demand uncertainty: Includes high side uncertainty of 20-25 MW over one to four years based on past peak demand forecasts and actual weather normalized peak data. This sensitivity was developed for the previous Near-term Generation Adequacy analysis.[47]

The base forecast is provided in Table 4 and the sensitivity forecasts are provided in Table 5.

Table 4: P90 Peak Demand Forecast[48]

Base Case Winter Demand Forecast				
	P90			
	2018-2019	**2019-2020**	**2020-2021**	**2021-2022**
Customer Coincident Demand (MW)	1718	1718	1716	1716
Transmission Losses (MW)	47	47	47	47
Station Service (MW)	24	24	24	24
Total Island Interconnected System Demand (MW)	**1789**	**1789**	**1787**	**1787**

[47] See *"Near-term Generation Adequacy Report,"* filed May 15, 2017.
[48] Differences in totals vs addition of individual components are due to rounding.

Table 5: Alternative Load Growth Scenarios[49]

	Sensitivity I Stable Utility Demand				Sensitivity II High Coincident Factor				Sensitivity III High Utility Uncertainty			
	2018-2019	**2019-2020**	**2018-2019**	**2021-2022**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**
Customer Coincident Demand (MW)	1743	1743	1743	1741	1738	1738	1736	1736	1738	1733	1731	1720
Transmission Losses (MW)	47	47	47	47	47	47	47	47	47	47	47	47
Station Service (MW)	24	24	24	24	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1814**	**1814**	**1814**	**1812**	**1809**	**1809**	**1807**	**1807**	**1809**	**1804**	**1802**	**1791**

6 System Constraints and Future Supply Risk

To fully understand the potential supply risk posed to the IIS in advance of North American grid interconnection, transmission, hydrological, and generation system analysis was required.

6.1 System Energy Capability

During October 2017, as part of Hydro's water management process, Hydro's Vista Decision Support System recommended an increase in thermal generation at Holyrood to reduce generation from the hydraulic system for the driest historic inflow sequences modelled. As Hydro continued its analysis, increasingly more historic sequences showed the need for additional thermal generation. To be proactive, Hydro increased thermal generation starting from November 2017 to February 2018 to reduce the hydroelectric generation required to assist with maintenance of reservoir levels. In March, this mode of operation was no longer required due to improved water levels in the reservoirs. Stand-by units were not used for water management purposes.

To the end of April in 2018, reservoir inflows have been 44% above average for the year. Weather conditions experienced in early 2018 contributed to material increases in hydraulic storage. As shown in Figure 2, Hydro's aggregate storage at the end of April was 1,276 GWh,

[49] Differences in totals vs addition of individual components due to rounding.

51% of Maximum Operating Level. Hydro continues to consider the critical dry sequence in the development of its minimum storage target to ensure its supply adequacy. Hydro will continue to report on available system energy as part of its *Energy Supply Report*, submitted monthly to the Board.

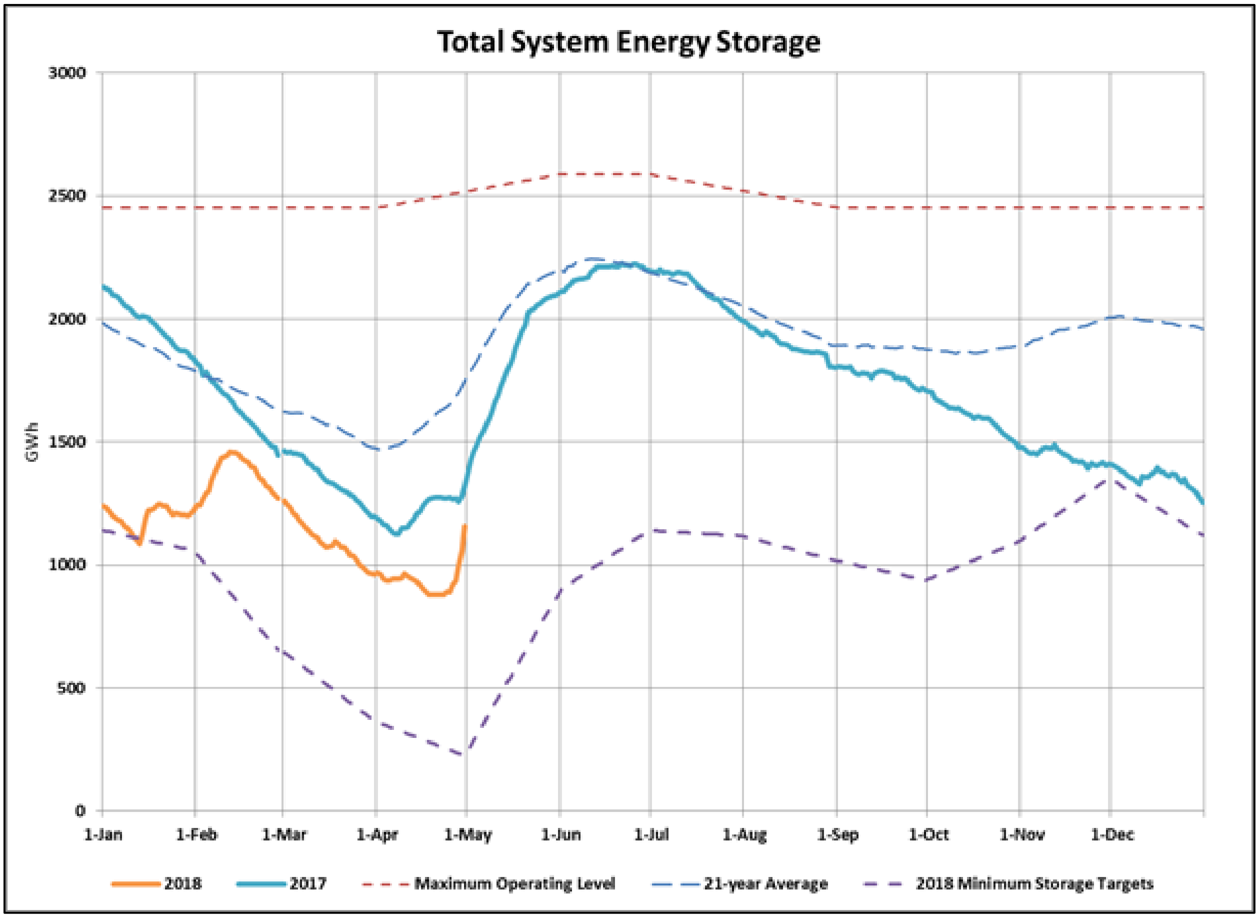

Figure 2: Total System Energy Storage

6.2 Transmission System Analysis

6.2.1 Transmission System Analysis Results

Load flow analysis confirms that there are no violations of Transmission Planning Criteria, as defined in Section 3.3. Previous reports required extended transmission planning analysis to determine the effects of transmission constraints on the Avalon Peninsula, with EUE as the measure of reliability used to perform this analysis. With the in-service of TL 267 this extended analysis is no longer required. EUE is still considered in this report; however, it is now analogous to LOLH.

6.3 Generation Planning Analysis

To determine the potential risk posed to the IIS from a generation capacity perspective, Hydro performed analysis to determine the impact on EUE (MWh), reserve margin (MW), and LOLH (hours) criteria of:

1. Thermal generation availability based on projected DAFORs, UFOPs, and DAUFOPs;
2. Hydraulic generation availability based on projected DAFOR; and
3. Revised peak demand forecast including sensitivities.

Additionally, in its report titled *"Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment Final Report,"* The Liberty Consulting Group (Liberty) asked that Hydro provide the Board with a brief report considering the impact on expected unserved energy for the following cases:

1. Holyrood DAFOR = 20%;
2. CT UFOP = 30% and 50%;
3. 50 MW variation in 2019/2020 peak demand versus the forecast; and
4. Two-year delay in Muskrat Falls.

The results for case 3 and the second half of case 2 are available in Appendix A. Results for cases 1,2, and 4 are in fact embedded throughout this report.

6.3.1 Transition to Plexos

The results for LOLH and EUE in the current report come from a model developed using the Plexos software package, which has superseded Hydro's retired Strategist model. As noted in Section 3.4, the Plexos tool allows for integrated modelling of generation availability and transmission constraints, allowing for the accurate calculation of both EUE and LOLH in the same software model. It is important to note that the equivalence of LOLH and EUE is subject to differences in parameters (e.g. unit size, forced outage rates, load shapes) and specific to the modelled system, in Hydro's case, the IIS. In migrating the model to Plexos, Hydro has updated a number of modelling parameters, including its load shape. Based on the results of the Plexos simulation, it has been determined that, given the most recent data, the equivalency point for a LOLH of 2.8 corresponds to an EUE 170 MWh.

6.3.2 Contracted Supply Case Parameters

The Contracted Supply Case reflects Hydro's anticipated system capability and P90 demand forecast with scheduled in-service dates of the Labrador-Island Link, the associated availability of recapture in excess of Labrador Interconnected System requirements, and Hydro's recently confirmed contracted supply from external markets.[50]

Currently the LIL is nearing completion and is expected to be in service in Q3 2018. While analysis in previous Near-Term Generation Adequacy reports assumed that there would be no power available over the LIL until after the winter of 2021-2022, given the anticipated energization is now less than two months away, Hydro no longer considers this to be a realistic supply scenario. Rather, to ensure conservatism as the LIL is a new asset, analysis was completed assuming a one-year delay in the in-service date of the LIL coupled with a 50% deration.

Given the conservative nature of this analysis, additional imports over the amounts contracted are not considered as there is no contract for firm capacity in place; however, Hydro notes that capacity may be available on a short-term basis to prevent a shortfall in generation or to displace more costly sources of generation.

[50] Hydro has contracted firm supply from external markets, the details of which will be shared confidentially with the Board.

The following assumptions were used to develop an additional case; the Contracted Supply Case for this analysis:

1. The study period is defined as Winter 2018-2019 through Winter 2021-2022 inclusive.
2. The Labrador-Island Link and the Soldiers Pond Synchronous Condensers: In service and available for the 2018-2019 winter peak.
3. For the duration of the study period, only excess recapture energy and firm contracted supply are considered available for Winter 2018-2019 and beyond.
4. For peak load operation, all Hydro and Newfoundland Power thermal generation is available and dispatched to maintain acceptable reserve levels for the IIS and the Avalon Peninsula.
5. Curtailable loads are assumed available as follows:
   - Corner Brook Pulp and Paper – 90 MW
   - Newfoundland Power – 9.9 MW
6. HTGS units are rated at 170 MW, 170 MW, and 150 MW.[51]
7. Asset reliability is modelled in accordance with the parameters expressed in Section 4.2.1
8. All other units rated in accordance with Hydro's expected operating conditions.

6.3.3 Conservative Supply Case Parameters

The Conservative Supply Case reflects increased conservatism, by not considering the benefit of the additional contracted supply. As such, for the duration of the study period, the only power available for import over the LIL would be firm recapture energy from Labrador at a capacity of 110 MW at Soldiers Pond. All other assumptions are consistent with Hydro's Contracted Supply Case. To maintain conservatism, all load sensitivity analysis has been conducted using the Conservative Supply Case as the base parameter.

[51] Normal operating limits continue to be 150 MW for both Units 1 and 2, and 135 MW for Unit 3.

6.3.4 Additional Cases

Other cases were analyzed to assess system reliability should more onerous system conditions or asset unavailability occur.

- **Sensitivities I-III:** Three alternative load growth forecasts were considered in this analysis. Discussion of the scenarios can be found in Section 5.1.
- **Increased GT DAUFOP:** The expected case with a 50% Forced Outage Rate for Stephenville and Hardwoods gas turbines. Please refer to Appendix A.
- **50 MW Increase in Load Forecast:** The expected case with the addition of 50 MW to the peak load. This could represent the addition of a new large customer. Please refer to Appendix A.
- **Derated HTGS** – The expected case with maximum HTGS capacities of:
  - Unit 1: 168 MW;
  - Unit 2: 141 MW; and
  - Unit 3: 150 MW.
- **LIL Reduced Capacity and Delayed In-Service:** The expected case with a delay of 1 year for the LIL and a reduction of the LIL capacity by 50%.

6.4 Results

6.4.1 Reserve Margin Analysis

Reserve margins for the Contracted Supply Case, Conservative Supply Case, and the four sensitivity load projections are presented in Table 6. Reserve margins remain at or in excess of the 240 MW criteria for all cases considered.

Table 6: Reserve Margin Analysis

Island Interconnected System P90 Demand Forecast Reserve Margin Analysis				
	Winter 2018-19	Winter 2019-20	Winter 2020-21	Winter 2021-22
Contracted Supply Case				
A: IIS Forecast Peak Demand	1,789	1,789	1,787	1,787
B: Capacity at Peak	2,101	2,101	2,101	2,101
C: Plus Available Capacity Assistance (100 MW) [1]	2,201	2,201	2,201	2,201
Reserve Margin (MW) (C-A)	412	412	413	413
Reserve Margin (%)	23.0%	23.0%	23.1%	23.1%
Conservative Supply Case				
A: IIS Forecast Peak Demand	1,789	1,789	1,787	1,787
B: Capacity at Peak	2,205	2,205	2,205	2,205
C: Plus Available Capacity Assistance (100 MW) [1]	2,305	2,305	2,305	2,305
Reserve Margin (MW) (C-A)	516	516	517	517
Reserve Margin (%)	28.8%	28.8%	29.0%	29.0%
Conservative Supply Case with Sensitivity Load Projection I				
A: IIS Forecast Peak Demand	1,814	1,814	1,812	1,812
B: Capacity at Peak	2,101	2,101	2,101	2,101
C: Plus Available Capacity Assistance (100 MW) [1]	2,201	2,201	2,201	2,201
Reserve Margin (MW) (C-A)	386	386	388	388
Reserve Margin (%)	21.3%	21.3%	21.4%	21.4%
Conservative Supply Case with Sensitivity Load Projection II				
A: IIS Forecast Peak Demand	1,809	1,809	1,807	1,807
B: Capacity at Peak	2,101	2,101	2,101	2,101
C: Plus Available Capacity Assistance (100 MW) [1]	2,201	2,201	2,201	2,201
Reserve Margin (MW) (C-A)	391	391	393	393
Reserve Margin (%)	21.6%	21.6%	21.7%	21.7%
Conservative Supply Case with Sensitivity Load Projection III				
A: IIS Forecast Peak Demand	1,809	1,804	1,802	1,791
B: Capacity at Peak	2,101	2,101	2,101	2,101
C: Plus Available Capacity Assistance (100 MW) [1]	2,201	2,201	2,201	2,201
Reserve Margin (MW) (C-A)	392	396	398	409
Reserve Margin (%)	21.7%	22.0%	22.1%	22.8%

1 **6.4.2 EUE and LOLH Analysis**

2 The Contracted Supply Case results in Table 7, indicate no violations of the planning criteria in
3 the study period across all assumptions, EUE and LOLH do increase with the HTGS DAFOR, as
4 expected.

Table 7: Contracted Supply Case[52]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	10	10	10	10
18%	16	16	15	15
20%	20	20	19	19
	Expected Customer Outage Hours			
15%	1,700	1,700	1,600	1,600
18%	2,600	2,600	2,500	2,500
20%	3,400	3,400	3,200	3,200
	LOLH			
15%	0.19	0.19	0.18	0.18
18%	0.29	0.29	0.28	0.28
20%	0.38	0.38	0.36	0.36

5 The Conservative Supply Case results in Table 8, indicate no violations of the planning criteria in
6 the study period across all assumptions, EUE and LOLH do increase with the HTGS DAFOR, as
7 expected.

[52] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours = 28,000;

Table 8: Conservative Supply Case[53]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	37	37	36	35
18%	57	57	55	55
20%	74	74	71	71
	Expected Customer Outage Hours			
15%	6,200	6,200	5,900	5,900
18%	9,600	9,600	9,200	9,200
20%	12,400	12,400	11,900	11,900
	LOLH			
15%	0.69	0.69	0.66	0.66
18%	1.05	1.05	1.00	1.00
20%	1.34	1.34	1.28	1.28

EUE and LOLH for the Conservative Supply Case using the three sensitivity load projections[54] is presented in Table 9, Table 10, and Table 11. There is no violation of the EUE and LOLH criteria for any of the forecasts.

[53] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.
[54] A discussion of the Load Growth Scenarios can be found in Section 5.2.

Table 9: Conservative Supply Case with Load Sensitivity I[55]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	58	58	55	55
18%	88	88	84	84
20%	113	113	108	108
	Expected Customer Outage Hours			
15%	9,600	9,600	9,200	9,200
18%	14,700	14,700	14,000	14,000
20%	18,900	18,900	18,100	18,100
	LOLH			
15%	1.04	1.04	0.99	0.99
18%	1.55	1.55	1.49	1.49
20%	1.97	1.97	1.89	1.89

Table 10: Conservative Supply Case with Load Sensitivity II[56]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	83	83	51	51
18%	81	81	78	78
20%	105	105	100	100
	Expected Customer Outage Hours			
15%	8,800	8,800	8,400	8,400
18%	13,500	13,500	12,900	12,900
20%	17,400	17,400	16,700	16,700
	LOLH			
15%	0.96	0.96	0.92	0.92
18%	1.44	1.44	1.38	1.38
20%	1.83	1.83	1.75	1.75

[55] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.
[56] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.

Table 11: Conservative Supply Case with Load Sensitivity III[57]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	52	48	46	38
18%	80	74	71	59
20%	104	96	92	76
	Expected Customer Outage Hours			
15%	8,700	8,100	7,700	6,400
18%	13,400	12,400	11,800	9,800
20%	17,300	16,000	15,300	12,700
	LOLH			
15%	0.95	0.88	0.84	0.71
18%	1.43	1.33	1.27	1.07
20%	1.81	1.69	1.62	1.37

Table 12 represents the Conservative Supply Case with the Holyrood Units derated to 168, 141 and 150 MW. This represents the expected capacity of Holyrood if the chemical cleaning of the economizers is not done this year. Table 13 represents a one year delay in the in-service date of the LIL and a 50% decrease in the amount of power available over the LIL once it is in service. Table 14 represents extreme operating conditions assuming a delay of the LIL, a deration of Holyrood and the highest forecast from Sensitivity 2.

The results in the following tables demonstrate that the availability and capacity of the LIL has the largest impact on the supply adequacy of the IIS, reflected in the variability of LOLH and EUE when subjected to variation in LIL parameters. A delay in the LIL would cause violations in the criteria for all considered system conditions. A material decrease in capacity available over the LIL, caused by technical problems on the LIL or increased demand from customers in Labrador, could result in criteria violations, especially if the DAFOR at Holyrood is higher than expected. Concurrent higher than anticipated unavailability of HTGS units would compound this issue. While Hydro has presented an Extreme Operating Conditions Case, Hydro maintains that the

[57] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.

scenario is very unlikely as it relies on the occurrence of three extreme unexpected conditions, a delay of the LIL, a deration of HTGS and the highest load forecast from Sensitivity II.

Table 12: Conservative Supply Case with Reduced HTGS Capacity[58]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	43	43	41	41
18%	65	65	62	62
20%	83	83	79	79
	Expected Customer Outage Hours			
15%	7,100	7,100	6,800	6,800
18%	10,800	10,800	10,300	10,300
20%	13,800	13,800	13,200	13,200
	LOLH			
15%	0.80	0.80	0.77	0.77
18%	1.19	1.19	1.14	1.14
20%	1.51	1.51	1.44	1.44

Table 13: Conservative Supply Case with LIL Delay and 50% Derate [59]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	202	97	93	93
18%	303	147	141	141
20%	385	188	180	180
	Expected Customer Outage Hours			
15%	33,600	16,100	15,400	15,400
18%	50,400	24,500	23,400	23,400
20%	64,200	31,300	30,000	30,000
	LOLH			
15%	3.40	1.70	1.63	1.63
18%	4.95	2.52	2.41	2.41
20%	6.19	3.18	3.05	3.06

[58] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.
[59] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.

Table 14: Extreme Operating Conditions Case[60]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	326	158	151	151
18%	475	233	223	223
20%	593	293	280	280
	Expected Customer Outage Hours			
15%	54,300	26,400	25,200	25,200
18%	79,100	38,800	37,100	37,100
20%	98,900	48,900	46,700	46,700
	LOLH			
15%	5.46	2.75	2.63	2.63
18%	7.70	3.94	3.77	3.77
20%	9.44	4.88	4.67	4.67

7 Conclusion

In all cases considered reserve margin remains in excess of 21%.

For Hydro's anticipated supply case (the Contracted Supply Case), including sensitivity assessments on the same, there was sufficient generation to meet system peak demand requirements and satisfy system planning criteria for the study period, as demonstrated by the EUE and LOLH results.

While some of the supply scenarios, including the Extreme Operating Case scenario, do result in violations of planning criteria, Hydro considers this analysis to be conservative, and the cases considered unlikely. Hydro continues to consider these cases to increase its operational awareness and ensure that there is organizational understanding around the resultant risk, should serious issues materialize. This better positions Hydro to proactively respond and mitigate issues.

[60] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOL=2.80.

From an asset reliability perspective, Hydro has conducted a thorough assessment of its assets and the potential risks to the reliable operation of key generation assets. Hydro has also determined reasonable projection for availability metrics based on historical data and the anticipated impact of planned improvements.

From an energy perspective, based on Hydro's asset reliability and in consideration of the critical dry sequence, Hydro remains confident in its ability to meet IIS energy requirements.

From a demand perspective, Hydro has performed analysis to determine the level of reliability on the system under a number of variations in the load forecast and system conditions. In addition to the base forecast, Hydro constructed three sensitivity demand forecasts to examine the effects of different load growth projections. Hydro also performed analysis on seven cases to determine the effects of different system conditions on its capability to supply customers.

The 2018 in-service of the Maritime Link and the Labrador-Island Link, combined with recapture energy and contracted supply from external markets, ensure Hydro is well positioned to reliably supply customers through Winter 2021-2022 in absence of generation from the Muskrat Falls Generation Station.

Appendix A

P50 Forecast Analysis

P50 Peak Demand Forecast

As part of this analysis, Hydro has updated both its P50 and P90 peak demand forecasts to reflect the latest available customer and system information. The revised P50 forecast, including the contribution of each of customer coincident demand, transmission losses, and station service is provided in Table A-1.

Table A-1: P50 Peak Demand Forecast

Base Case Winter Demand Forecast				
	P50			
	2018-2019	**2019-2020**	**2020-2021**	**2021-2022**
Customer Coincident Demand (MW)	1657	1657	1655	1655
Transmission Losses (MW)	47	47	47	47
Station Service (MW)	24	24	24	24
Total Island Interconnected System Demand (MW)	**1728**	**1728**	**1727**	**1727**[61]

[61] Differences in totals vs addition of individual components due to rounding.

Appendix B

Additional Analysis Requested as part of Liberty's report titled "Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment"

Table B-1: Conservative Supply Case with Addition of 50 MW to Peak Demand for the Study Period [62]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	87	87	83	83
18%	132	132	126	126
20%	169	169	162	162
	Expected Customer Outage Hours			
15%	14,500	14,500	13,900	13,900
18%	22,000	22,000	21,100	21,100
20%	28,100	28,100	26,900	26,900
	LOLH			
15%	1.52	1.53	1.46	1.46
18%	2.25	2.26	2.17	2.16
20%	2.84	2.85	2.73	2.73

Table B-2: 50% DAUFOP Case for Hardwoods and Stephenville Gas Turbines for Conservative Supply Case[63]

Summary of Results				
P90 Analysis				
Year	**2019**	**2020**	**2021**	**2022**
HRD DAFOR	**Expected Unserved Energy (MWh)**			
15%	54	54	52	52
18%	83	83	80	80
20%	107	107	103	103
	Expected Customer Outage Hours			
15%	9,000	9,000	8,600	8,600
18%	13,900	13,900	13,300	13,300
20%	17,900	17,900	17,100	17,100
	LOLH			
15%	0.99	0.99	0.95	0.95
18%	1.48	1.49	1.42	1.42
20%	1.89	1.89	1.81	1.81

[62] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOLH=2.80.
[63] Planning Criteria is EUE=170 MWh; Annual Expected Outage Hours=28,000; LOLH=2.80.