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May 15, 2017

The 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 Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Near-term Generation Adequacy Report

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 the original plus 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

Geoffrey P. Young
Corporate Secretary & General Counsel

GPY/bds

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Roberta Frampton Benefiel – Grand Riverkeeper Labrador
Dennis Browne, Q.C. – Consumer Advocate
Danny Dumaresque

ecc: Denis Fleming- Vale Newfoundland & Labrador Limited
Larry Bartlett – Teck Resources Ltd.

REGISTERED PROFESSIONAL ENGINEER PEG RENEE E. HODDER Renée E. Hodder SIGNATURE May 15, 2017 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador JENNIFER M. WILLIAMS SIGNATURE May 15, 2017 DATE NEWFOUNDLAND & LABRADOR	Transmission & Distribution
	Telecontrol
	System Planning

Near-term Generation Adequacy Report

May 15, 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

1.0 Executive Summary

This report, titled "*Near-term Generation Adequacy Report*", provides the Board with an assessment of Hydro's overall asset health and a subsequent risk assessment of its ability to meet Island Interconnected System (IIS) energy and demand requirements until the expected interconnection with the North American grid.

The scheduled in-service of the Labrador Island Link and availability of recall energy in excess of Labrador requirements to the IIS will result in sufficient generation to meet system peak demand requirements and satisfy system planning criteria. The scheduled in-service of the Maritime Link and the access it provides to the North American grid will further bolster IIS reliability.

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 conducted a thorough assessment of its assets and determined reasonable projections for availability metrics. Hydro concludes that once TL267 is placed in service, expected unserved energy (EUE) is within Hydro's planning criteria for all forecasts considered. Should the in-service of TL267 be delayed such that TL267 is not available for the winter 2017-18 peak, Hydro concludes that there is risk of EUE in excess of planning criteria. As such, the in-service of TL267 remains Hydro's priority focus in terms of improving system reliability for customers until interconnection to the North American grid is achieved.

In response to this Board's letter dated October 13, 2016, Hydro intends to file its Near Term Generation Adequacy report semi-annually, on May 15 and November 15 of each year through interconnection.

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2.0 Introduction

On September 16, 2015, Hydro filed "*A Report to the Board of Commissioners of Public Utilities on Generation Adequacy*". This report considered the Island Interconnected System (IIS) and detailed the latest P90 forecast, the forecast of generation reserves over the near term (four years, through the end of 2018), and Hydro's generation performance over the previous year.

In its letter dated February 8, 2016, the Board of Commissioners of Public Utilities (the Board) requested Hydro undertake to provide a full risk assessment for the IIS in relation to generation supply (capacity and energy) until the expected North American Grid interconnection, including alternatives and options available to address the energy supply circumstances in the interim. Hydro filed its "*Energy Supply Risk Assessment*" report on May 20, 2016. An update to this report was filed on November 30, 2016.

The information provided in the Energy Supply Risk Assessment was twofold. It provided information regarding Hydro's supply risk, that is, its asset reliability and generation supply in terms of both energy and capacity until the expected North American Grid interconnection. It also provided information regarding its supply risk should the expected interconnection be delayed through winter 2019-20.

In its letter, dated October 13, 2016, the Board requested that Newfoundland and Labrador Hydro (Hydro) provide:

> *Semi-annual reports on May 15 and November 15 each year on generation adequacy for the Island Interconnected system.*

This report, titled "*Near-Term Generation Adequacy Report*", provides the Board with information regarding the IIS previously included as part of either the Generation Adequacy report, or the Energy Supply Risk Assessment. The majority of the report addresses Hydro's capability to meet IIS peak demand requirements and provide reliable service to its customers. The report also addresses energy capability of, and requirements for, the IIS. In response to the Board's request, Hydro intends to file its Near Term Generation Adequacy report semi-annually, on May 15 and November 15 of each year through interconnection.

Following interconnection, Hydro intends to provide the Board with annual updates on its generation capability in a manner consistent with the previously published Generation Planning Issues Report, last issued in November 2012.

Finally, 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 (EUE) for the following cases:

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

The results for cases 1 through 3 are available in Appendix C: Considerations as per Liberty's Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment Final Report. Results for case 4 are in fact embedded throughout this report, as with the exception of the Expected Case, all analysis has been done on the basis of continued isolated island operation, meaning no interconnection to the North American grid via either the Labrador Island Link (LIL) or the Maritime Link (ML), through winter 2021-22. This represents a further two year delay in in-service.

3.0 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*[1] 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…*

Hydro operates nine hydroelectric generating stations, one oil-fired plant, four gas turbines and twenty-five diesel plants. 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.

3.1 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. Part of this system is comprised of two parallel 230 kV lines, TL202 and TL206, which bring energy to the Avalon Peninsula where demand is concentrated. The Holyrood Thermal Generating Station, a large oil-fired thermal generating plant, is also located on the Avalon Peninsula. Figure 1 presents a visual overview of Hydro's current generation and transmission infrastructure both on the island of Newfoundland and in Labrador.

[1] *Hydro Corporation Act, 2007*, SNL 2007, c.H-17.

Figure 1 - Hydro’s Generation and Transmission Infrastructure

3.2 Generation and Transmission Infrastructure – Post Interconnection

After integration of the Muskrat Falls Project assets,[2] the IIS will have two interconnections to the North American grid via the Labrador Island Link (LIL) and the Maritime Link (ML). The planned in-service of a third 230 kV transmission line from Bay d'Espoir to the Avalon Peninsula, TL267, in the fall of 2017 will increase Hydro's capability to deliver power to the major load centre on the Avalon Peninsula. Figure 2 presents a visual overview of Hydro's generation and transmission infrastructure following the completion of the Muskrat Falls Project and interconnection to the North American grid.

[2] The Muskrat Falls Project includes an 824 megawatt hydroelectric generating facility at Muskrat Falls, the Labrador-Island Link that will transmit power from Muskrat Falls to Soldiers Pond on the Avalon Peninsula, and the Maritime Link connecting Newfoundland and Nova Scotia, which is being constructed by Emera Inc. of Nova Scotia.

Figure 2 - Hydro's Generation and Transmission Infrastructure Post Interconnection

4.0 System Planning Criteria

4.1 Load Forecasting

Hydro now bases its generation supply planning decisions on a P90 peak demand forecast.[3,4] The P90 peak demand forecasts reflects an associated increase in demand over a normalized, or P50, peak demand forecast that results from instances of more severe wind and/or cold temperatures. During P90 weather conditions, the peak demand will exceed the normalized, or P50, demand level. The development of the P90 peak demand forecast for the medium term is an extension of Hydro's regularly prepared system operating load forecast.

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, which means the probability of the actual load being higher than the forecast load is 50 percent and the probability of the actual load being lower than the forecast load is also 50 percent. The development of the P50 load allows Hydro to forecast expected or average system energy requirements across specific time intervals, as well as, assess the expected peak demand as part of its operating load requirements.

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 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.

[3] 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.

[4] 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.

4.2 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 generation planning 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. Hydro's 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.[5]

Energy: The Island Interconnected System should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability.[6]

Additionally, as discussed in *Hydro's Response to the Phase I Report by Liberty Consulting* (the Hydro Reply),[7] Hydro now maintains a megawatt (MW) reserve of greater than 240 MW on the IIS. This 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 a spinning reserve of 70 MW.

[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. 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 a given year.

[6] 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.

[7] http://pub.nl.ca/applications/IslandInterconnectedSystem/files/corresp/NLH-Phase-I-Reply-Submission-re-Liberty-Group-Report-2015-02-06.pdf.

4.3 Transmission Planning Criteria

The transmission system on the island of Newfoundland is assessed and expanded based upon a 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;
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.

4.4 Combined Generation and Transmission Planning Outlook

Currently, Hydro uses LOLH, reserve margin, and EUE to assess generation adequacy. Each measure has strengths and limitations and includes some aspects that the others do not. If all three measures generally indicate similar results; i.e. violation or no violation, this indicates a robust analysis.

As noted in Section 4.2, existing Generation Planning Criteria defines an LOLH target of 2.8 hours per year. As illustrated in Figure 3 below, analysis indicates that LOLH is positively correlated with Expected Unserved Energy (EUE).[8]

In previous risk assessments, the correlation of LOLH and EUE determined that 300 MWh of EUE was approximately equivalent to an LOLH of 2.8.

[8] Expected unserved energy is the summation of the expected number of MWh of load that will not be served in a given year as a result of demand exceeding available capacity. The correlation was performed by combining Generation and Transmission Planning analysis techniques. Generation adequacy analysis allowed for the quantification of the LOLH for each year of the study period. A Transmission Planning study was then performed where load flow analysis was used to determine system capacities for key contingencies. These capacities were then used in combination with event probabilities and load duration curves to quantify EUE.

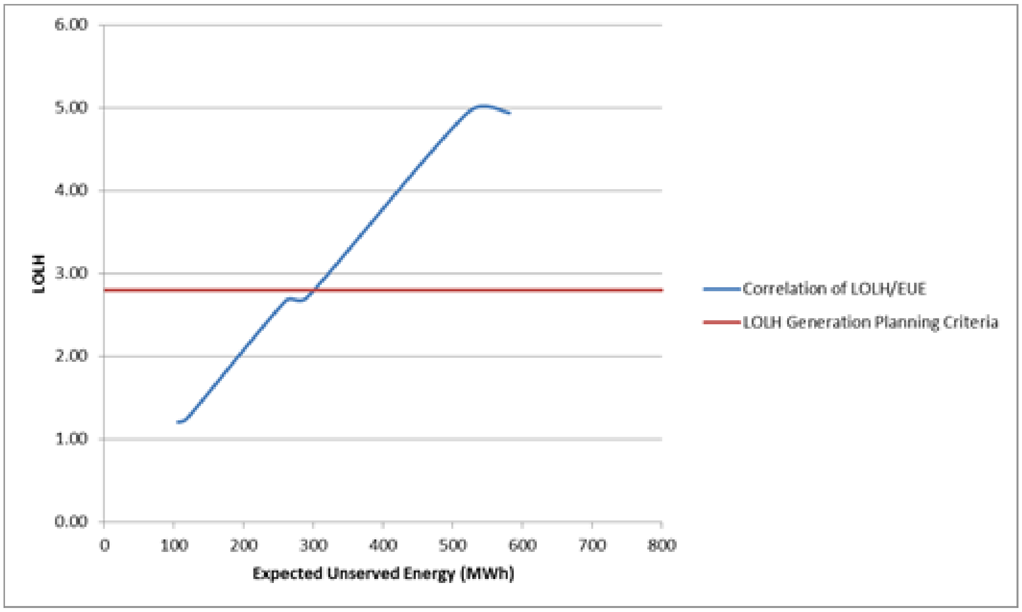

Figure 3 – Illustration of EUE vs LOLH

Changes in the IIS, including the in-service of TL267, have required an update of the system model. As expected, this has resulted in an alternate equivalency point between LOLH and EUE, which remain well correlated. Given the metrics are different indicators of reliability, Hydro remains confident that the 300 MWh target remains appropriate for the IIS. While the parameters take different approaches in their assessment of system adequacy, the overall results are similar.

Traditionally, Hydro has solely relied upon LOLH analysis to assess the ability of its installed generation to meet its demand requirements. LOLH is a probabilistic analysis that evaluates the system's ability to meet an hourly load requirement, defined by an underlying system load shape, in a given period. Any inability to meet that requirement, regardless of the magnitude of violation, counts as a loss of load. The hours of violation are subsequently summed across the year, and reported as an annual total. As such, the LOLH metric provides more insight into the number of violations that can be expected in a given year (i.e. number of hours in which potential exists for loss of load), while providing little insight into the size of violations themselves (i.e. violations could range from as little as 1 MW to multiple MW).

Hydro's inclusion of EUE in its planning criteria provides a more descriptive measure of Hydro's overall exposure for unserved load, that is the actual amount of load that may be unserved. This measure is particularly appropriate at this point in time, given Hydro's pending interconnection to the North American grid and the associated increase in installed capacity, which will result from the in-service of the Labrador Island Link and the Muskrat Falls Generating Station.

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. Hydro currently uses an LOLH threshold of 2.8 and an EUE threshold of 300 MWh annually. While these thresholds are defined, a calculated LOLH or EUE does not mean the system can expect exactly those results at the end of the year. Rather, results in excess of the utility's thresholds indicate that there is an increased likelihood 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. By conducting joint analysis of EUE, LOLH and reserve margin, Hydro has strengthened its analysis of the potential for loss of supply.

For further discussions of results, please refer to Section 7.4.

5.0 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 28, 2017, for the quarter ending March 31, 2017. These reports detail any unit reliability issues experienced in the previous 12 month period. Performance is discussed in comparison with the previous 12 month period, a year prior.

Hydro has taken actions to address repeated issues, including: broader reviews which frequently involved external experts, addressing issues with urgency, and an increased focus on asset reliability. These actions will result in improved reliability this coming winter and in near term operating seasons, as evidenced by the improvements in Hydro's end-customer reliability.

5.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro reviewed the factors affecting generating unit reliability since the ESRA filed November 2016. This report provides updates on items as required and discusses additional items which 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 5.1.1 through 5.1.3 provides an overview of the repeat or broader issues. Isolated equipment issues, for example 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 Utilization Forced Outage Probability (UFOP).

The following sections provide a description of recurring 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.

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

1. Seven areas of discussion for its hydraulic facilities (Bay d'Espoir penstock 1, Paradise River plant, lightning, frazil ice, Bay d'Espoir Unit 7 vibration, Upper Salmon rotor key cracking, and Hinds Lake bearing coolers);
2. Five areas of discussion for its thermal facilities (unit boiler tubes, variable frequency drives, air flow limitations due to normal boiler fouling during operating season, turbine control system, and exciter controls); and
3. Five areas of discussion for its gas turbines (fuel lines, fuel valve failures, snow doors at Hardwoods, Stephenville End A vibration, and automatic voltage regulation at Hardwoods).

5.1.1 Hydraulic

Bay d'Espoir Penstock 1

Penstock 1 is a 50 year old buried penstock at the Bay d'Espoir plant serving both Units 1 and 2. Following two leaks in 2016 and subsequent significant refurbishment of deteriorated welds, the penstock was returned to service on November 30, 2016, in advance of winter 2016/17.

The root cause investigation for the cause of the leaks and weld deterioration is now complete. A report discussing the root cause was submitted to the Board on March 23, 2017. The cracks developed due to corrosion of the welds occurring in an area of high stress. In consideration of the root cause findings, Hydro developed plans to inspect and refurbish other penstocks in the fleet, if required.

Some specific actions taken include: an inspection of the Hinds Lake penstock in fall of 2016, with no concerns noted; application for and approval of a project to refurbish the penstock welds of Bay d'Espoir penstock 2;[9] inspection of penstock 3 at Bay d'Espoir in April 2017 with preliminary findings that no refurbishment is currently required; detailed analysis of required penstock cover at Bay d'Espoir; associated maintenance and capital planning incorporating the results of the root cause report and penstock cover analysis; and, planning of future maintenance or upgrades required arising from inspections and associated field findings or analysis.

This substantial focus on penstock condition, and on the associated maintenance and refurbishment, materially reduces the risk of an unplanned outage of a generator due to penstock leaks.

Paradise River plant

As discussed in the November 2016 ESRA, Paradise River (8 MW plant located on the Burin Peninsula) was experiencing a high number of trips in 2016. Hydro focused on identifying the root cause. To do so, Hydro identified and worked through a number of potential causes, including working with Newfoundland Power on the replacement of a recloser in the Monkstown substation. While the recloser that had been in place was functioning, it was of an older vintage. Since its replacement, there has been a significant improvement over the frequency of trips experienced prior to recloser replacement. Hydro continues to monitor this situation but considers this issue to be resolved.

Lightning

Some of Hydro's generating units connected to the IIS via radial transmission lines (such as Granite Canal (41 MW), Upper Salmon (84 MW), Cat Arm (127 MW) and Paradise River (8 MW))

[9] Per Board Order No. P.U. 13(2017), Hydro filed a letter with the Board on May 15, 2017 detailing the findings of the inspection which confirmed the requirement to refurbish the penstock welds in penstock 2.

are susceptible to tripping during lightning strikes to the transmission lines. While lightning is not considered to have a 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. 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). This 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. Hydro is continuing to investigate the energy supply impacts of lightning.

Note that in 2017, TL269 is scheduled to be in-service. This will provide an alternate connection to Granite Canal and Upper Salmon, reducing the risk of loss of supply due to a lightning event for those plants.

Frazil Ice

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 builds at plant intakes, impacting the amount of water that can be drawn into the plant, thereby reducing the generating unit capability. In Hydro's experience, such conditions have previously resulted in unavailability of units at its hydraulic plants. Outages due to frazil ice have been less frequent in comparison to previous years. The relatively lower frequency is attributed to differing environmental conditions, as well as to improvements in detection systems. Hydro has undertaken a number of such improvements, including the replacement of water temperature sensors with more accurate devices that are more strategically located. This change provides improved data, enabling operators to better respond to frazil icing situations by making dispatch changes.

Hydro also optimizes the trashrack[10] differential alarm settings at its plants known to have increased likelihood of frazil icing. These plants include Hinds Lake, Upper Salmon, and Granite Canal. This provides Hydro with a better awareness of frazil ice levels, thereby providing the opportunity to de-ice the trashrack and avoid an extended outage of several days.

Finally, there has been a concerted effort by ECC operators to proactively manage frazil icing and subsequently reduce related unit trips. Operators closely monitor ice cover, water temperature, wind speed, and trashrack differential during frazil ice season. Unit dispatch is optimized to allow solid ice cover to form based on the operators' assessment of these parameters in conjunction with system conditions. This further reduces frazil ice risk.

Hydro did not experience a forced outage due to frazil ice in winter 2016-17. This can be largely attributed to the extra attention placed on the condition monitoring and preventative actions taken to minimize the impacts of frazil ice.

Improvements to the frazil ice detection system at Granite Canal are part of the 2017/2018 Hydraulic Structures Refurbishment capital project. This project will improve the detection system to include more parameters that will be better able to detect frazil ice conditions and thus prevent forced outages.

[10] The trashrack is generally a set of bars that is located at the intake and will act as a large filter to prevent large debris, such a tree branches, from entering the penstock and into the generating unit. Build up of "trash" (trees, etc.) or ice impedes water flow into the penstock and affects generation output.

Bay d'Espoir Unit 7 Vibration

Unit 7 in Bay d'Espoir is the largest hydraulic unit in Hydro's fleet at 154 MW. Historically, this unit had two generator loading zones that were operationally avoided as the vibration experienced in these zones had been found to cause damage or result in a unit trip. Further, the unit frequently required multiple attempts to start in order to achieve operable vibration levels, and therefore, taking the unit offline was avoided due to concerns regarding the restart of the unit.

To address this issue, the generator guide bearing was replaced as part of the unit overhaul in 2016. Since this replacement, unit vibration levels have improved considerably to levels better than experienced in the past thirty years. This improvement has increased the range of acceptable operating loads and also increased the likelihood of the unit starting on first attempt. This change is positive and will contribute to enhanced reliability performance.

Following the generator guide bearing replacement, the unit was started and stopped once in October 2016. The unit start produced acceptable vibration levels. To confirm that the replacement of the generator guide bearing was successful in reducing vibration levels, more starts and stops will be planned for 2017. Hydro continues to monitor and, in the interest of being conservative, will consider the issue resolved only after an additional period of operating experience.

Upper Salmon Rotor Key Cracking

Upper Salmon is the second largest hydraulic generating unit on the island interconnected system at 84 MW. This generator has experienced fretting corrosion[11] in recent years, indicating movement between the rotor spider and rotor rim. Due to the floating rim design,

[11] Fretting corrosion is a form of accelerated atmospheric oxidation which 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.

some movement is expected; however, an overhaul, which is included as part of Hydro's 2018 capital plan, is required to check if the movement is greater than can be tolerated. The scope of this overhaul includes a refurbishment of the rotor to address this issue, if necessary.

Until the planned refurbishment in 2018, left unchecked this issue would present a near term risk to operation of the Upper Salmon unit. More than desirable movement between the rotor spider and rotor rim can cause cracking of the rotor rim key welds. Recently, the frequency of cracked rotor rim key welds has been increasing. Initially, the cracked welds were limited to the larger rim keys that could be driven back in place and re-welded with limited risk to unit operation. In March 2017, one of the smaller rim keys on the top of the unit cracked and started to move from its position. 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. To address this risk, in consultation with an OEM engineer, Hydro has increased the frequency of visual inspections of rim key welds. If broken welds are found, immediate action is taken to reweld. This process will also occur during the upcoming 2016 annual maintenance outage. Following the annual outage, the inspections and any required rewelding will continue through the next 12-18 months. This process will allow for reliable operation of the unit until the planned refurbishment in 2018.

Hinds Lake Bearing Coolers

Hydro implemented a bearing cooler replacement program in recent years, with new coolers installed in several plants to date. The Hinds Lake Unit (75 MW) contains six generator bearing coolers. Based on the history and consultation with the Original Equipment Manufacturer, these coolers were targeted for purchase as critical spares in 2020.

In spring of 2017, leaks were experienced in the cooling system at the Hinds Lake plant, requiring pressure testing of all coolers. The testing revealed that three of six coolers were leaking. The damaged coolers were isolated from the system and Hydro completed testing on the reduced cooling capacity. Test results indicated the cooling from the four remaining coolers is adequate at current ambient air and water temperatures. It is being monitored to ensure that with higher ambient temperatures the unit will be derated until safe to increase load. Hydro has several options for ensuring appropriate cooling in advance of winter 2017/18 and will have a solution in place prior to winter.

5.1.2 Thermal

Unit Boiler Tubes

Each of the three thermal generating units at Holyrood Thermal Generating Station (Holyrood) 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 de-ratings in winter 2015/16. Affected tubes were replaced during annual planned unit outages in 2016, prior to the 2016/17 winter season. There were no boiler tube related outages or deratings in winter 2016/17.

In response to the reheater tube failures in winter 2015/16, Hydro hired a boiler consultant, AMEC Foster Wheeler (AMEC), to complete an assessment of the condition of the boiler tubes in all three units. This study assessed the thinnest tube thickness measurements[12] observed since 2010 in each boiler section, the operating pressures and temperatures, and the remaining expected creep[13] life for the superheater and reheater tubes. The final conclusion from this work was that the boiler tubes in all three boilers are in good shape and there was no recommendation for any derating.

[12] Failure is typically experienced in thinning tubes.
[13] Boiler tube creep is a time-dependent deformation or weakening of tube metal that occurs above certain threshold temperatures, which are dependent on the metal used. Superheater and reheater tubes are prone to failure by creep over time. Creep life calculations consider the tube material and wall thickness, and the operating temperature and pressure to predict the operating life of the tube.

Annual boiler maintenance outages will be completed in 2017 and in future years for all three units. The work will include tube thickness surveys to confirm future operating season unit output. Hydro will continue to proactively monitor tubes and replace tubes during these outages, if necessary. If required, Hydro will complete targeted replacements annually.

Further, to ensure the operational integrity of these units and to minimize loading stresses, Hydro has adapted its operating parameters for these units to operate at the maximum continuous rating (MCR) of 170 MW for units 1 and 2 and 150 MW for unit 3 only when necessary. These units are now normally operated to a maximum of 150 MW for units 1 and 2 and 135 MW for unit 3.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at Holyrood. The Variable Frequency Drives (VFDs) were installed to vary the amount of air required based on generation need. This reduces auxiliary power requirements and results in fuel savings. Previous to winter 2016/17 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. The VFDs operated reliably throughout the 2016/2017 winter operating season.

Hydro continues to work with Siemens in 2017 and will work with them during the annual outages to complete a full inspection of the drives, and will implement any appropriate improvements as required to ensure continued reliable operation.

Air Flow Limitations

Appropriate air flow is required to provide enough air for combustion, enabling units to provide full output. Holyrood Units 1 and 2 boilers have experienced air flow limitations since 2015. These normally developing limitations gradually increase over time, resulting in capacity restrictions of up to 60 MW, on occasion. Unit 3 has not experienced material air flow limitations such as those experienced on Units 1 and 2 because, due to design differences, the economizer[14] in this unit is much less prone to fouling, and the air heaters are slightly larger than the Unit 1 and Unit 2 air heaters. The economizer fouling was the primary driver for the deratings due to air flow through winter 2016-17.

To address air flow limitations, Unit 1 and 2 boiler tuning was completed in the fall of 2016 after the lower reheater sections had been replaced during the annual maintenance outage work completed on both units. When the units were returned to service after the outages and boiler tuning completed, Unit 2 was capable of full load operation. Unit 1 remained derated at 165 MW, higher than the deration of 155 MW before the reheater failures and subsequent derating to 120 MW that occurred in winter 2015/16. Based on the results of the tuning, Hydro concluded the root cause of the air flow issues on both units is the additive effect of fouling[15] through various sections of the economizer, ducting, boiler, air heaters and flues, and air heater leakage.

Air flow restrictions and the associated deratings worsened through the 2016-17 operating season. Hydro has taken action to limit the system impact by conducting air heater washes and

[14] The economizer is a heat transfer device within the boiler that captures waste heat from boiler flue gases and transfers it back to the boiler feedwater thereby increasing thermal efficiency of the unit.

[15] Fouling in this context refers to an accumulation of boiler ash and other similar debris in various components of the air and gas paths through the boiler and associated ducting. Fouling can reduce boiler performance by reducing heat transfer if the deposits accumulate on heat transfer surfaces, and by flow restrictions if the deposits accumulate in areas where the cross sectional flow area of air or gas is significantly impacted.

additional sootblowing.[16] Air heater washing is possible during the operating season but requires a short (approximately 2 day) outage to complete. During the 2016-17 operating season, Hydro completed several air heater washes in attempt to maintain the load capability of Unit 1 and Unit 2. The effectiveness of these washes in restoring unit output diminished with time as the rest of the boilers, including the economizer sections, continued to foul.

To further restore unit capacity, the units require effective cleaning throughout. Effective cleaning of the boiler requires significant outage time, as much as two weeks, as well as a specialized contractor for the economizer due to the restricted work area and access. Cleaning of the Unit 1 boiler is scheduled during the 2017 annual outage starting in June. At that time Hydro plans to upgrade the air heaters and some key expansion joints to reduce air leakage, which is also considered to be a material issue with respect to available air flow. A supplemental Capital Budget Application entitled "Reliability Improvements" has been submitted to the Board, which includes the air heater and expansion joint work.

For Unit 2, a two week outage was completed in April 2017. During the outage the boiler, including the economizer, was cleaned. Following completion of this cleaning, unit output increased from 135 MW to 165 MW. The air heater and expansion joint upgrades for Unit 2, also included in the "Reliability Improvements" supplemental capital project, are planned for the annual outage scheduled for September 2017. It is expected that upon completion of all aspects of this work, full unit capability will be restored.

Turbine Control System (Mark V System)

A governor system controls the steam flow into a turbine and maintains consistent unit speed. The General Electric (GE) Mark V turbine control system was installed on Units 1 and 2 in 2003 and 1999, respectively. GE moved the Mark V system into the obsolescence phase of its

[16] Sootblowing refers to the periodic online cleaning of the boiler surfaces by injection steam back into the boiler unit.

lifecycle at the end of 2014. At that time, Hydro entered a revitalization agreement with GE to increase the reliability of the now obsolete system. Given the expected remaining life of Holyrood at the time, this option was determined to be more appropriate than upgrading the governor control system. To further mitigate risk, Hydro bolstered its stock of spare Mark V cards, as new cards were no longer being produced.

During 2016, several hardware card failures either caused a unit trip or kept a unit from returning to service. Through its stock of spares and the revitalization agreement, Hydro was able to quickly remedy these issues. GE has made several site visits and continues to actively monitor the health of the system.

In 2016 GE completed an in-depth review of the quantity and condition of all parts and related equipment on site by a Mark V service technician. As a result of this work, Hydro has increased the stock of selected spare parts and added additional spare parts to its inventory.

There were no issues with this system component during the 2016/2017 operating season. Hydro continues to work with GE to bolster reliability. Hydro and GE are working towards an agreement for additional support for the Mark V system including increasing the available technical expertise for support of the Mark V system.

Exciter control systems

Each generating unit at Holyrood has an excitation system that controls the unit output voltage, which contributes to maintaining an acceptable Island Interconnected System (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.

In recent years, Hydro has been managing reliability issues of the control system through the utilization of the available spare parts. ABB has stated that parts and technical support for the exciter control modules installed on Units 1 and 2 are in the obsolescence phase, meaning that they will be limited or not available in the future. The lack of parts and technical support from ABB affects Hydro's ability to maintain reliable operation of Units 1 and 2. Recent card failures in December 2016 resulted in a heightened risk of loss of customer supply. As such, Hydro is advancing a plan to improve the reliability of the exciters.

To ensure reliable operation of the units, the control sections of the exciters will be replaced with the modern Unitrol 6080 equipment. Hydro applied for approval of this project through a supplemental Capital Budget Application, approved by the Board in Order P.U. 10(2017). The installation and commissioning will be executed in 2017 prior to the winter operating season.

5.1.3 Gas Turbines

Hydro continues to identify, investigate, and resolve reliability issues related to the operation of the Stephenville and Hardwoods gas (combustion) turbines (GT). While many reliability issues have been resolved since 2014, increased use of the units for system support and their increasing age have resulted in additional items for Hydro to identify and manage. Hydro is currently completing 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 have been reported on in the *Gas Turbine Failure Analysis Recommended Actions Implementation Update* report filed with the Board on April 18, 2016[17]. In addition, selected planned capital upgrades to critical systems are being executed to ensure reliable operation of these units until end of life.

[17] An update to the status of the actions taken to improve gas turbine reliability will be submitted on June 30, 2017.

The Holyrood Combustion Turbine has been operating more reliably than Hardwoods and Stephenville. As with any generator on the IIS, Hydro investigates any issue and implements corrective action. In 2017 Hydro engaged the OEM in a service contract. This service agreement will provide assistance to Hydro in maintaining reliable service from this unit.

Fuel Lines at Stephenville and Hardwoods

In recent years, Hydro has experienced fuel line leaks at both the Stephenville and Hardwoods gas turbines in recent years. The impacts of these leaks have ranged from temporary unit unavailability to longer term unit unavailability as a result of fires within the units. As a result of investigations, quality control issues with the supply of the fuel lines were determined to be the root cause. All fuel lines were replaced with quality assured service appropriate lines.

Hydro has had no recurring issue with the fuel lines since replacement over the previous winter and in 2016. This issue is considered resolved.

Fuel valve failures at Hardwoods

Hydro had experienced multiple unit outages as a result of fuel valve failures in the newly installed fuel control valves at Hardwoods. Failure analysis conducted by the valve OEM determined that the valve was being operated in excess of its pressure rating. This was determined to be the likely cause of valve failure, as opposed to an issue with the valve itself. By moving the fuel supply to the valve downstream of a pressure regulator rather than upstream from the regulator, the valve was able to be supplied at a lower pressure level.

There have been no subsequent pressure induced valve failures and the issue with these valves is considered to be resolved.

Hydro continues to gain experience regarding the normal wear and tear and life expectancy of these valves. Hydro maintains multiple spares on hand and promptly replaces the valves if issues occur. Further, Hydro is engaging the OEM to inspect these valves as they are removed to confirm that no other issues exist.

Snow Doors Upgrade at Hardwoods

The Hardwoods and Stephenville gas turbines are equipped with pneumatically operated snow doors which prevent snow from entering the exhaust stacks. These doors must remain open during operation. During the winter of 2015/16, the existing snow door system at Hardwoods experienced issues with various system components which resulted in delayed starting of the unit and failed starts. Primary causes were the proximity switch mounting hardware, control wiring failures, seized bearings, and freezing due to moisture ingress into the air system. Upon investigation of the snow door system, Hydro determined an upgrade would improve its reliability.

Hydro completed the upgrade in the summer of 2016. The upgrade included replacement of the proximity switches with a unit that has longer control leads; overhaul of the pneumatic cylinders that open and close the doors; replacement of junction boxes containing the control wiring; and, addition of lubrication connections on the pneumatic cylinder bearings.

There have been no further snow door related impacts on unit reliability since completion of the upgrade work in 2016 and the system operated reliably through the 2016-17 winter period. This issue is considered resolved.

End A Vibration at Stephenville

All of the gas turbines are equipped with a vibration detection system to protect from failures which exhibit at increasing vibration levels. Historically, the vibration limits for Stephenville End

A were set higher than recommended by the engine OEM, Rolls Royce. In 2016, the engine installed in Stephenville End A[18] experienced a bearing failure and was sent to an overhaul facility for refurbishment. As a result of this failure, the vibration settings were reviewed and reduced to comply with the Rolls Royce recommended settings.

Upon the return of the refurbished engine in December 2016, the refurbished gas turbine was reinstalled in End A in Stephenville, where it experienced unacceptably high levels of vibration. This engine was removed and Alba Power's loaner engine was installed in January 2017. In March 2017, Alba's loaner engine also began experiencing unacceptable levels of vibration and was removed from service.

Hydro's continued investigation suggests there may be a problem with Stephenville End A berth or support structures that is inducing an unacceptable level of vibration in the gas turbine. Hydro continues to investigate the source of the vibration with Alba Power, the OEM. It is currently anticipated that required corrective actions to address the vibration issue with Stephenville End A will be completed in Q3 2017.

Automatic Voltage Regulator at Hardwoods

The voltage being produced by the Hardwoods alternator is controlled by an automatic voltage regulator (AVR). The AVR sets the alternator voltage while operating in either generate or synchronous condense modes. In November 2016 and March 2017, the alternator tripped while operating in synchronous condense mode, as a result of system conditions. Upon investigation, it was determined that the AVR had entered a fault state as a result of the trip, which prevented the alternator from synchronizing with the power system. Once the fault was investigated and cleared, the unit was returned to service.

[18] Engine serial number 202204.

Hydro is currently investigating the source of the issues being experienced which result in a trip of the unit and subsequent synchronizing issues. If an AVR fault occurs, it typically takes several hours to return the unit to service. It is anticipated that the investigation will be completed and corrective actions implemented prior to the start of the 2017-18 winter operating season.

5.2 Selection of Appropriate Performance Ratings

5.2.1 Consideration of Asset Reliability in System Planning

As identified in Section 4, Hydro's asset reliability is a critical component in determining its ability to meet the System 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.

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 = 14%
Holyrood GT	UFOP = 5%
Stephenville GT	UFOP = 20%
Hardwoods GT	UFOP = 20%

In determining appropriate reliability metrics for its thermal units, hydraulic units, and standby units, Hydro reviewed the projected availability noted in its November 30, 2016 ESRA, the asset performance through winter 2016-17, and the projected availability for near-term winter seasons (as discussed in Section 5.1 above). There has been no change required for the hydraulic and thermal DAFORs. In consideration of gas turbine reliability, Hydro has also included the Deration Adjusted Utilization Forced Outage Probability (DAUFOP) metric, as a sensitivity run in this analysis. Hydro intends to continue to evaluate the appropriateness of both (UFOP) and DAUFOP in assessing and projecting the reliability of its gas turbines.

5.2.2. Discussion of the DAUFOP measure

Hydro is evaluating alternate or additional measures of generating unit reliability. Hydro previously noted that a new metric was being investigated to account for unavailability of capacity at gas turbines. In its most recent review, Liberty commented that DAUFOP should be considered for both the gas turbines and for the units at Holyrood.

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. The calculation includes both outages that remove the unit from service completely and instances when units are de-rated.[19]

This measure is defined by the Canadian Electricity Association (CEA) and North American Electric Reliability Corporation (NERC) similarly. The DAUFOP calculation was developed from IEEE Standard 762-2006. The formula is as follows:

Formula,

$$DAUFOP\ (\%) = \frac{\{f(FO + FEMO + FEPO)\ + O(FD)adj\}}{f(FO + FEMO + FEPO) + O + O(FD) + O(SD)}$$

[19] If a unit's output is reduced by more than 2%, the unit is considered de-rated by the Canadian Electricity Association (CEA) guidelines. Per CEA guidelines, to account for deration of a generating unit, the operating time at the de-rated level is converted into an equivalent outage time.

Where:

FO =	number of hours the unit was in a forced outage state
FEMO =	the number of hours the unit was in a forced extension of a maintenance outage state
FEPO =	the number of hours the unit was in a forced extension of a planned outage state
O(FD) =	the number of hours the unit was operating under a forced derating
O =	the number of hours the unit was in the operating state during the period
O(SD) =	the number of hours the unit was operating under a scheduled derating during the period
O(FD)*adj* =	the number of hours the unit was operating under a forced derating converted to an equivalent outage time. X is the percent derating of Maximum Continuous Rating (MCR)[20].

$$O(FD)adj = \left(\frac{100 - X}{100}\right) * O(FD)$$

Hydro continues to use UFOP as a reliability measure for its GTs. UFOP is defined as the probability that a generating unit will not be available due to a forced outage when required to generate. This measure does not consider unit deratings, but rather assumes the unit is available at 100% of its capacity when required. Additionally, it only considers the hours that the unit is needed for operation. This metric may not provide an accurate reflection of what can be counted on to support the IIS. For example, during previous operations at Hardwoods and Stephenville, engine failures have resulted in a 50% reduction in plant capacity, with no effect on the calculated UFOP for either plant.

Hydro has included DAUFOP in this report as a sensitivity consideration. Hydro continues to evaluate the individual benefits of both DAUFOP and UFOP, recognizing that the use of DAUFOP

[20] For example if a generating unit is derated to 80 percent of its MCR for 5 hours, that would be equivalent to a full outage of the generating unit for 1 hour.

as an indication of GT reliability would reflect all periods where GT unit deratings impact available system generation.

The reliability of the Holyrood thermal units is currently measured using the DAFOR metric. This metric measures the percentage of the time that a unit, or group of units, is unable to generate at its maximum continuous rating due to forced outages. This measure includes unit deratings in its calculation. DAUFOP can also be calculated for these units, however the DAUFOP calculation results in a slightly lower, and therefore less conservative, value than the associated DAFOR. Given Hydro's focus on conservative assessment of Holyrood unit reliability, Hydro intends to continue to use DAFOR to measure Holyrood unit reliability as it is more conservative than DAUFOP.

6.0 Load Forecast

Hydro's load forecast for the Island Interconnected System is comprised of three components; 1) customer requirement, 2) transmission loss requirement, and 3) station service requirement. The customer 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.[21] Hydro relies on these inputs to determine a forecast of customer coincident demand for a five-year period. Transmission losses are determined by transmission system load flow analysis based on forecast customer coincident demand. Station service is the demand and subsequent energy consumed by Hydro's generating stations. In the existing Island Interconnected System, Holyrood is the largest contributor to the IIS station service requirement. The primary reporting and system planning measure is the megawatt winter peak demand for the island's 60 Hz system.

[21] 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.

Based on Hydro's assessment of the peak demand impact of more severe weather condition, the P90 peak demand forecast adds an additional 60 MW in customer coincident over the P50 demand forecast. Should the in-service of TL267 be delayed, the winter 2017-18 P90 peak demand forecast will have an approximate incremental 10 MW of transmission losses over the P50 demand forecast for a total of 70 MW.[22]

As part of this risk assessment, Hydro has updated both its P50 and P90 peak demand forecasts to reflect the latest available customer and system information. 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

Base Case Winter Demand Forecast						
	P90					
	2016/17[1]	2017/18	18/19	19/20	20/21	21/22
Customer Coincident Demand (MW)	1712	1737	1733	1724	1712	1693
Transmission Losses (MW)	64	50	50	50	50	50
Station Service (MW)	24	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1800**	**1811**	**1806**	**1798**	**1785**	**1766**

Notes:
1. 2016/17 forecast as per Hydro's ESRA, filed November 30 2016.
Differences in totals vs addition of individual components due to rounding

6.1 Discussion of Hydro's Winter 2016-17 Peak Demand

The Island Interconnected System experienced the highest electrical load for the winter of 2016-17 on February 8, 2017. As Corner Brook Pulp and Paper were curtailed under the current Capacity Assistance arrangements during the core peak hours of that morning, Hydro has

[22] It is noted that transmission losses are a function of two factors that include total system load and net power flow to the Avalon Peninsula. The incremental load associated with the P90 peak demand forecast includes more than 30 MW of load on the Avalon Peninsula. The increase in transmission losses is therefore attributed to both factors.

reconstructed what Corner Brook Pulp and Paper load would have been across that day had the Capacity Assistance arrangements not been imposed.

Table 3 provides the reconstructed and summarized customer peak demands for February 8, 2017, as well as the forecast base case coincident customer class loads for the winter peak period.

Table 3 - Customer Peak Demands - Winter 2016-17

	P90 Forecast[1]	P50 Forecast[1]	Actual[2]
Utility[3]	1551	1490	1514
Industrial[4]	162	162	155
IIS Customer Coincident Demand[5]	1712	1652	1669

Notes:

1. Forecast as per Hydro's ESRA, filed November 30 2016.
2. Actual peak projected to have occurred between 8:00 AM and 9:00 AM on February 8, 2017.
3. IIS coincident demand of Newfoundland Power and Hydro Rural Retail.
4. Industrial actual MW reconstruction assumes CBPP at pre-curtailment demand level.
5. IIS coincident customer peak demand excluding transmission losses and station service.

The actual utility demand at peak of 1514 MW was approximately 24 MW higher than the P-50 forecast and 37 MW lower than the P-90 forecast. While wind chill conditions leading up to the peak period were less onerous than P-50 peak demand wind chill conditions as measured and tracked by Hydro, the temperatures leading up to the peak period were colder than the historical average as tracked by Hydro. Weather conditions across the island on the morning of the peak can be characterized as being cold with low winds[23] resulting in utility loads that were driven predominately by temperature. Based on historical weather records tracked by Hydro, the temperatures leading up to the peak period were 2^{o}C colder than average peak

[23] On the morning of February 8th, wind speeds on the Avalon Peninsula and south coast were such that no wind generation was available to the IIS at time of peak.

temperature conditions which equates to a P75 temperature level. The wind speeds leading up to the peak period were of same magnitude as the lowest wind speeds in Hydro's peak demand weather records.

The actual (reconstructed) industrial demand at peak of 155 MW was lower than forecast and resulted from higher than forecast demand at peak for the Corner Brook Pulp and Paper mill that was more than offset by lower than forecast demand at peak for all other industrial operations on the IIS.

At the total IIS customer demand level, the actual (reconstructed) coincident demand of 1669 MW was one percent (17 MW) higher than the P-50 forecast of 1652 MW.

6.2 Quantification of Forecast Peak Uncertainty

Liberty has recommended Hydro assess the impact of a 50 MW variation in the 2019-20 peak demand versus the forecast. Hydro has assessed the suggested 50 MW variation, however it is Hydro's opinion that the analytical basis of the suggested +50 MW variation in demand has not been well founded.

The largest contributor of high side uncertainty to the IIS peak demand forecast is considered by Hydro to be the peak demand forecast for the Newfoundland Power Service Territory (NPST). To quantify the high side uncertainty, a review of the deviations between the demand forecasts of the NPST and the actual weather normalized peak demand[24] for this service territory was completed. The NPST represents approximately 85% of IIS customer demand requirements and accounts for much of the IIS peak demand forecast uncertainty. Table 4 provides a summary of deviations based on the past peak demand forecasts and actual weather

[24] Comparing forecast demand to weather normalized actual demand removes the demand component associated with weather variation and provides a more accurate indication of the forecast variance which is non-weather related.

normalized peak data. Based on this assessment the average high-side forecast deviation for a peak demand forecast for one to four years into the future would be expected to be approximately 20 to 25 MW assuming past years forecast accuracy is indicative of current forecast accuracy.

Table 4 - Assessment of Forecast Accuracy

	Average MW Over Forecast	# of Forecasts	Average MW Under Forecast	# of Forecasts	Average MW Error	# of Forecasts
One Year Ahead	25	9	19	4	23	13
Two Years Ahead	28	8	17	4	24	12
Three Years Ahead	29	6	17	5	24	11
Four Years Ahead	24	6	26	4	25	10

Note: Data based on the peak demand forecasts prepared annually since 2003.

Industrial demand represents approximately 10% of forecast IIS customer demand requirements at system peaks. Based on the load information indicated and provided to Hydro by the existing industrial customers, only the two industrial loads associated with nickel refining at Long Harbour have indicated growth over the next three years. While it is plausible that Vales' nickel processing facility load could be higher than is currently forecast over the next three years, the considerable amount of processing experience already obtained by Vale at their facility, combined with persistent under-forecasting of demand requirements to date, suggests to Hydro that Vale's load would likely be no higher than forecast. The load of the oxygen manufacturing facility associated with the nickel processing plant represents about ten percent of the total nickel processing load and the load experience indicates a stable demand requirement. Without an expansion of the current oxygen producing facility, Hydro considers this facility's demand to present insignificant high-side demand risk across a three-year forecast period.

The other large industrial customer loads are mature, having existed for many years and have been either stable or have been declining. Of the three existing mature industrial customer loads, Hydro considers only CBPP to present more than one megawatt of high side load uncertainty as its load requirement is currently forecast to decline by three megawatts over the next three years with load reductions dependent on unproven process improvements. The oil refinery's firm demand requirements have historically ranged from 29.5 to 32 MW and are currently forecast at the higher level of 32 MW. Without an expansion or major modification of the current refinery operations, Hydro considers this facility's demand to present insignificant high side demand risk across a three year forecast period. Overall, Hydro perceives the high-side firm demand uncertainty for existing industrial customers to be no more than three to five MW for the next three years.

Other than what Hydro perceives as minor load uncertainty associated with the existing industrial loads, there is also the consideration of any large unforeseen loads. At the present time, Hydro is not aware of any significant new industrial or commercial loads on the island that are imminent over the short term. Hydro anticipates that new load developments of significance to the system would be staged in conjunction with the completion of either Muskrat Falls or the transmission line connections to Labrador and Nova Scotia.

IIS rural retail load served by Hydro accounts for approximately five percent of forecast IIS customer demand requirements at system peaks. At this time Hydro has not quantified non-weather related uncertainty associated with the peak demand forecasts for the rural retail load but has calculated the combined weather and non-weather demand forecast uncertainly for one to four years ahead to be approximately four MW. The quantified MW uncertainty is based on a review of the deviations between the demand forecasts and actual peak demands for the IIS rural retail customer group prepared since 2003.

6.3 Sensitivity Load Growth Scenarios

To ensure a robust assessment of risk, Hydro continues to consider the three P90 sensitivity forecasts first presented in its ESRA, as filed November 30, 2016. In addition, Hydro has developed another two P90 sensitivity forecasts to provide a more fulsome analysis. The five sensitivity forecasts being considered in this analysis are detailed below:

- Sensitivity Load Projection I - Stable utility demand: Assumes that in spite of the current forecast, which is for declining energy requirements, demand requirements remain stable (i.e. lower load factor);
- Sensitivity Load Projection II - High industrial coincidence: Includes increased industrial load requirement over Hydro's base case expectation assuming less diversity in industrial customer demand requirements at island Interconnected system peak;
- Sensitivity Load Projection III - High utility coincidence: Includes increased utility load requirement over Hydro's base case expectation assuming less diversity in utility customer demand requirements at Island Interconnected system peak;
- Sensitivity Load Projection IV – 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; and
- Sensitivity Load Projection V – Combines early forecast from Sensitivity Load Projection IV (winter 2017-18 through winter 2019-20) and later forecasts from Sensitivity Load Projection I (winter 2020-21 through winter 2021-22). Presents the most onerous combined forecast on considered scenarios.

The sensitivity forecasts are summarized in Table 6. For ease of comparison, the Base Case forecast is again provided in Table 5.

Table 5 – P90 Peak Demand Forecast

Base Case Winter Demand Forecast						
	P90					
	2016/17[1]	2017/18	18/19	19/20	20/21	21/22
Customer Coincident Demand (MW)	1712	1737	1733	1724	1712	1693
Transmission Losses (MW)	64	50	50	50	50	50
Station Service (MW)	24	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1800**	**1811**	**1806**	**1798**	**1785**	**1766**

Notes:

1. 2016/17 forecast as per Hydro's ESRA, filed November 30 2016.

Differences in totals vs addition of individual components due to rounding

Table 6 - Alternative Load Growth Scenarios

Alternative Load Growth Scenarios															
	Sensitivity I: Stable Utility Demand					Sensitivity II: High Industrial Load					Sensitivity III: High Utility Coincidence				
	2017/18	18/19	19/20	20/21	21/22	2017/18	18/19	19/20	20/21	21/22	2017/18	18/19	19/20	20/21	21/22
Customer Coincident Demand (MW)	1737	1740	1739	1739	1739	1747	1744	1736	1724	1705	1749	1744	1736	1723	1704
Transmission Losses (MW)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Station Service (MW)	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1811**	**1814**	**1813**	**1813**	**1813**	**1821**	**1818**	**1810**	**1798**	**1778**	**1823**	**1818**	**1810**	**1797**	**1778**

Note: Differences in totals vs addition of individual components due to rounding

Alternative Load Growth Scenarios cont.										
	Sensitivity IV: Assessed Customer Demand Uncertainty					Sensitivity V: Combined Sensitivity I and IV				
	2017/18	18/19	19/20	20/21	21/22	2017/18	18/19	19/20	20/21	21/22
Customer Coincident Demand (MW)	1757	1754	1747	1737	1718	1757	1754	1747	1739	1739
Transmission Losses (MW)	50	50	50	50	50	50	50	50	50	50
Station Service (MW)	24	24	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1831**	**1828**	**1821**	**1811**	**1792**	**1831**	**1828**	**1821**	**1813**	**1813**

7.0 System Constraints and Future Supply Risk

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

7.1 System Energy Capability

Hydro's firm and average supply capabilities exceed Hydro's current forecasted energy requirements through 2022. As such, Hydro is not at significant risk of being unable to meet forecast energy requirements. This analysis assumes that the Holyrood units are available at their normal operating limits, as presented in Table 7, with an applied DAFOR of 14%. Hydro continues to provide the Board with monthly updates regarding system hydrology in its Monthly Energy Supply Report.

Table 7 – System Capability (GWh)

	HTGS Capability (GWh)	Hydraulic and Purchases Capability (GWh)	**Total System Capability (GWh)**
Holyrood units 1,2 at 150 MW, Holyrood Unit 3 at 135 MW, Holyrood Plant DAFOR = 14%	2,570	5,629	**8,199**

Note: This system capacity excludes standby generation, which is not anticipated to be required to meet energy requirements.

7.2 Transmission System Analysis

System capacities under various operating scenarios were quantified and exposures for unserved energy were investigated. The base case transmission planning analysis now includes 11 MW of curtailable load, as approved by the Board in Orders No. P.U. 55(2016) and No. P.U. 3(2017), and the in-service of TL267. Transmission planning analysis also determined the impact of the in-service of the Labrador Island Link and the Maritime Link and the delayed in-service of TL267.

7.2.1 The Avalon Transmission System

Demand on the Avalon Peninsula is supported by the following sources of supply:

- Thermal generation from: Holyrood Units, Holyrood Gas Turbine, Hardwoods Gas Turbine, and Holyrood Diesels;
- Hydraulic Generation from Newfoundland Power Units;
- Thermal Generation from Newfoundland Power's mobile diesel generator;
- Diesel Generation at Vale Terminal Station;
- Capacity Assistance from Vale Newfoundland & Labrador Limited (Vale);
- Capacity Assistance from Praxair Canada Inc. (Praxair);
- Wind Generation;[25] and
- 230 kV transmission lines TL203, TL237, and TL 267 at the Western Avalon Terminal Station.

7.2.2 Transmission System Analysis Results

Load flow analysis confirms that there are no violations of Transmission Planning criteria, as defined in Section 4.3, for worst case based on the reference case assumptions.

7.2.3 Extended Transmission Planning Analysis

An extended Transmission Planning analysis was performed to assess the exposure for unserved energy for various operating scenarios beyond the scope of Transmission Planning criteria. These scenarios included consideration of loading conditions and outages to multiple units on the Avalon Peninsula.

For the purposes of this analysis, it was assumed that the Holyrood thermal units are operating at their gross continuous unit ratings, in accordance with Hydro's Operating Instruction T-093,

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[25] Wind generation is not considered to be online in this analysis as it is not considered to have firm capability.

as presented in Appendix B and the recommendations of Hydro's Asset Management team as discussed in section 5.1.2. These ratings are summarized in Table 8.

Table 8 –Capacity for Holyrood Units

Unit	Capacity (MW)
Holyrood Unit 1	170
Holyrood Unit 2	170
Holyrood Unit 3	150

Loss of Multiple Holyrood Units

Once TL267 is placed in-service, transmission constraints on the Avalon Peninsula are eliminated to the extent that the loss of two Holyrood units will not result in transmission system violations. Rather, the loss of two Holyrood units over peak would result in a shortfall of generation for the IIS. With the loss of two Holyrood units, the total Island Interconnected System capacity is limited to approximately 1700 MW. Similarly, total Island Interconnected System capacity for three Holyrood units out of service is limited to approximately 1410 MW.

7.3 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 expected unserved energy (EUE; MWh), reserve margin (MW), and loss of load hours (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.

7.3.1 Expected Case Parameters

The Expected Case reflects Hydro's anticipated system capability and P90 demand forecast with scheduled in-service of the Labrador Island Link and Maritime Link. The following assumptions were used to develop the Expected Case for this analysis:

1. The study period is defined as winter 2017-18 through winter 2021-22 inclusive.
2. Key in-service dates:
    a. TL267: Available for the 2017/2018 winter peak.
    b. The Labrador Island Link, the Maritime Link, and the Soldiers Pond Synchronous Condensers: In-service and available for the 2019-2020 winter peak.
3. For the duration of the study period, the only power available for import over the LIL would be firm recall power from Labrador at a capacity of 110 MW at Soldiers Pond, available for winter 2018-19.
4. For conservatism, this analysis considers no import over the ML, though the ML will be in-service and available.
5. Newfoundland Power's mobile gas turbine is available and installed on the Avalon Peninsula.
6. 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.
7. Capacity assistance from Vale Inc. is 7.6 MW, as per Hydro's Operations Standard Instruction T-093, Island Generation Supply - Gross Continuous Unit Ratings (Appendix B).
8. Curtailable loads are as follows:
    - Corner Brook Pulp and Paper – 80 MW
    - Newfoundland Power – 9.9 MW (9 MW on the Avalon Peninsula)
    - Vale – 6 MW
    - Praxair – 5 MW

9. Holyrood units are rated in accordance with Table 9.

Table 9 – Holyrood Unit Ratings

	Rating (MW)		
	Unit 1	Unit 2	Unit 3
Normal Operation	150	150	135
Maximum Operation	170	170	150

10. All other units rated in accordance with Hydro's Operations Standard Instruction T-093, Island Generation Supply - Gross Continuous Unit Ratings (Appendix B).

7.3.2 Fully Stressed Reference Case

The Fully Stressed Reference Case is a conservative analysis reflecting Hydro's anticipated capacity in consideration of the P90 peak demand forecast should no interconnection to the North American grid be established through winter 2021-22.

Differences in assumptions between the Expected Case, detailed in Section 7.3.1, and the Fully Stressed Reference Case are noted below. All other assumptions are consistent between cases.

1. Key in-service dates:
    a. The Labrador Island Link, the Maritime Link, and the Soldiers Pond Synchronous Condensers are not expected in service for this analysis. As such, for the duration of the study period, no power can be imported over the LIL or ML.

7.3.3 Sensitivity Load Projections

Hydro performed additional analysis on the fully stressed reference case to determine the potential impact of the alternative load growth scenarios, discussed fully in Section 6.2. All other assumptions remained consistent with the Fully Stressed Reference Case.

7.3.4 Delayed in service of TL267

As detailed in Hydro's previously filed ESRAs, the in-service of TL267 is critical in mitigating Hydro's EUE in advance of interconnection to the North American grid. The completion of TL267 remains on schedule for in-service by October 31, 2017. Hydro actively manages potential risks to the project schedule and provides monthly updates to the Board regarding project status. There is no anticipation of delayed in-service, however, given the importance of TL267 in mitigating EUE for the coming winter, Hydro felt it appropriate to consider the impact of a one year delayed in-service for this asset.

7.4 Results

7.4.1 Reserve Margin Analysis

Reserve margins for the Expected Case, Fully Stressed Reference Case, and the five sensitivity load projections are presented in completed on a P90 forecast are presented in Table 10. The Fully Stressed Reference Case with Sensitivity Load Projection V is the most onerous scenario presented in Table 10. Reserve margins remain at or in excess of 15% for all cases considered.

Table 10 - Reserve Margin Analysis

Island Interconnected System P90 Demand Forecast Reserve Margin Analysis					
	Winter 2017-18	Winter 2018-19	Winter 2019-20	Winter 2020-21	Winter 2021-22
Expected Reference Case					
A: IIS Forecast Peak Demand	1,811	1,806	1,798	1,785	1,766
B: Less Available Capacity Assistance (90 MW)	1,721	1,716	1,708	1,695	1,676
C: Capacity at Peak	2,006	2,006	2,116	2,116	2,116
Reserve Margin (MW) (C-B)	285	290	408	421	440
Reserve Margin (%)	17%	17%	24%	25%	26%
Fully Stressed Reference Case					
A: IIS Forecast Peak Demand	1,811	1,806	1,798	1,785	1,766
B: Less Available Capacity Assistance (90 MW)	1,721	1,716	1,708	1,695	1,676
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	285	290	298	311	330
Reserve Margin (%)	17%	17%	17%	18%	20%
Fully Stressed Reference Case with Sensitivity Load Projection I					
A: IIS Forecast Peak Demand	1,811	1,814	1,813	1,813	1,813
B: Less Available Capacity Assistance (90 MW)	1,721	1,724	1,723	1,723	1,723
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	286	283	283	283	283
Reserve Margin (%)	17%	16%	16%	16%	16%
Fully Stressed Reference Case with Sensitivity Load Projection II					
A: IIS Forecast Peak Demand	1,821	1,818	1,810	1,798	1,778
B: Less Available Capacity Assistance (90 MW)	1,731	1,728	1,720	1,708	1,688
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	275	279	286	298	318
Reserve Margin (%)	16%	16%	17%	17%	19%
Fully Stressed Reference Case with Sensitivity Load Projection III					
A: IIS Forecast Peak Demand	1,823	1,818	1,810	1,797	1,778
B: Less Available Capacity Assistance (90 MW)	1,733	1,728	1,720	1,707	1,688
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	274	278	287	299	319
Reserve Margin (%)	16%	16%	17%	18%	19%
Fully Stressed Reference Case with Sensitivity Load Projection IV					
A: IIS Forecast Peak Demand	1,831	1,828	1,821	1,811	1,792
B: Less Available Capacity Assistance (90 MW)	1,741	1,738	1,731	1,721	1,702
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	265	268	275	285	305
Reserve Margin (%)	15%	15%	16%	17%	18%
Fully Stressed Reference Case with Sensitivity Load Projection V					
A: IIS Forecast Peak Demand	1,831	1,828	1,821	1,813	1,813
B: Less Available Capacity Assistance (90 MW)	1,741	1,738	1,731	1,723	1,723
C: Capacity at Peak	2,006	2,006	2,006	2,006	2,006
Reserve Margin (MW) (C-B)	265	268	275	283	283
Reserve Margin (%)	15%	15%	16%	16%	16%

Note: Installed capacity does not include 20 MW of voltage reduction

7.4.2 EUE and LOLH Analysis

The Expected Case results, contained in Table 11, indicate minimal EUE and LOLH, as the availability of the surplus recall power to the IIS mitigates the risk presented by the loss of multiple units at Holyrood given the current load forecasts.

Table 11 – Expected Case Results

P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)[1]**				
14%	112	0	0	0	0
15%	136	0	0	0	0
20%	302	0	0	0	0
	Expected Customer Outage Hours[1]				
14%	18,800	0	0	0	0
15%	22,500	0	0	0	0
20%	50,300	0	0	0	0
	LOLH				
14%	2.27	0.33	0.28	0.22	0.15
15%	2.63	0.39	0.33	0.26	0.19
20%	4.93	0.82	0.68	0.55	0.40

Note:

Planning Criteria is EUE = 300 MWh; 50,000 Annual Expected Outage Hours; LOLH = 2.80

1. Note that values of 0 do not indicate that Hydro expects no unserved energy, but rather, the increase in available supply has substantially reduced the liklihood of EUE, and subsequently Expected Customer Outage Hours to very low levels.

EUE and LOLH for the Fully Stressed Reference Case, the five sensitivity load projections, and the case using DAUFOP for Hardwoods and Stephenville Gas Turbines is presented in Tables 12 through 18. To provide more insight into the degree of uncertainty in variables and conclusions, results are provided for Holyrood Plant DAFORs of 14%, 15%, and 20%. By providing results for a 1% increase in plant DAFOR (Holyrood Plant DAFOR = 15%) and a severe plant DAFOR (Holyrood Plant DAFOR = 20%), the impact of DAFOR on EUE is more readily apparent. Note that a 20% DAFOR at Holyrood can be compared to having a unit unavailable at Holyrood three of every five days. Hydro maintains that the projected plant DAFOR of 14% is reasonable and based on thorough analysis.

Hydro reiterates the Fully Stressed Reference Case is a conservative analysis using the P90 peak demand forecast and reflects no interconnection at all to the North American grid within the period being analyzed (through winter 2021-22).

Table 12- Fully Stressed Reference Case

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	112	108	99	87	71
15%	136	130	119	105	85
20%	302	290	266	235	191
	Expected Customer Outage Hours				
14%	18,800	17,900	16,400	14,600	11,700
15%	22,500	21,800	19,900	17,500	14,200
20%	50,300	48,300	44,200	39,100	31,800
	LOLH				
14%	2.27	2.13	1.79	1.47	1.09
15%	2.63	2.47	2.08	1.71	1.27
20%	4.93	4.66	3.93	3.27	2.48

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 13 - Sensitivity Load Projection I: Stable Utility Demand

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	112	115	115	115	116
15%	136	140	139	139	140
20%	302	310	308	309	311
	Expected Customer Outage Hours				
14%	18,800	19,200	19,100	19,200	19,200
15%	22,500	23,300	23,200	23,300	23,400
20%	50,300	51,800	51,500	51,600	51,900
	LOLH				
14%	2.27	2.31	2.15	2.08	1.99
15%	2.63	2.67	2.48	2.40	2.29
20%	4.93	4.99	4.60	4.42	4.18

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 14 - Sensitivity Load Projection II: High Utility Coincidence

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	126	122	112	98	81
15%	152	148	135	119	98
20%	336	327	301	265	218
	Expected Customer Outage Hours				
14%	21,000	20,500	18,700	16,400	13,500
15%	25,300	24,600	22,500	19,900	16,300
20%	55,900	54,500	50,100	44,200	36,400
	LOLH				
14%	2.54	2.42	2.10	1.71	1.28
15%	2.93	2.80	2.42	1.98	1.49
20%	5.43	5.19	4.50	3.73	2.85

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 15 - Sensitivity Load Projection III: High Industrial Coincidence

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	128	123	111	98	80
15%	154	148	135	118	97
20%	341	328	299	264	216
	Expected Customer Outage Hours				
14%	21,300	20,500	18,700	16,300	13,400
15%	25,700	24,800	22,400	19,800	16,100
20%	57,000	54,700	49,900	44,000	36,000
	LOLH				
14%	2.60	2.45	2.07	1.71	1.26
15%	3.00	2.83	2.39	1.98	1.47
20%	5.54	5.24	4.46	3.73	2.82

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 16 - Sensitivity Load Projection IV: Assessed Customer Demand Uncertainty

P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	138	134	126	113	93
15%	166	162	152	136	112
20%	368	358	336	303	250
	Expected Customer Outage Hours				
14%	22,900	22,400	21,000	18,900	15,400
15%	27,600	27,000	25,300	22,600	18,700
20%	61,300	59,800	56,000	50,500	41,700
	LOLH				
14%	2.89	2.75	2.36	2.03	1.51
15%	3.32	3.17	2.72	2.34	1.75
20%	6.06	5.80	4.99	4.33	3.30

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 17 - Sensitivity Load Projection V: Combined Sensitivity I and IV

P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	138	134	126	115	116
15%	166	162	152	139	140
20%	368	358	336	309	311
	Expected Customer Outage Hours				
14%	22,900	22,400	21,000	19,200	19,200
15%	27,600	27,000	25,300	23,300	23,400
20%	61,300	59,800	56,000	51,600	51,900
	LOLH				
14%	2.89	2.75	2.36	2.08	1.99
15%	3.32	3.17	2.72	2.40	2.29
20%	6.06	5.80	4.99	4.42	4.18

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 18 - Consideration of DAUFOP rather than UFOP for HWD, SVL GT

P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	162	155	144	129	109
15%	195	187	174	156	132
20%	432	415	385	345	291
	Expected Customer Outage Hours				
14%	26,900	25,900	24,000	21,500	18,200
15%	32,600	31,100	29,100	26,000	21,900
20%	72,000	69,300	64,200	57,500	48,500
	LOLH				
14%	2.90	2.73	2.29	1.88	1.39
15%	3.35	3.15	2.64	2.18	1.62
20%	6.17	5.84	4.91	4.09	3.11

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Based on the projected asset reliability discussed in Section 5.0, and demand forecasts discussed in section 6.0, no cases considered result in EUE in excess of Hydro's planning criteria of 300 MWh for Holyrood plant DAFORs of 14% or 15% for the fully stressed reference case and more onerous cases.

Given a Holyrood plant DAFOR of 20%, EUE in excess of planning criteria exists to varying degrees for each sensitivity case considered. The largest violation of Hydro's planning criteria occurs in consideration of the DAUFOP metric for Hardwoods and Stephenville gas turbines in conjunction with a 20% Holyrood plant DAFOR. This case results in EUE of 432 MWh in winter 2017-18, decreasing to 291 MWh in winter 2021-22. Note that this case projects extreme unavailability of generating units. A 20% DAFOR at Holyrood can be compared to having a unit unavailable at Holyrood three of every five days. In this particular case, this is combined with having the Stephenville gas turbine unavailable roughly every other day (DAUFOP = 48%) and the Hardwoods gas turbine unavailable roughly one of every three days (DAUFOP = 28%). It is Hydro's opinion that though this case results in high impact to the IIS, the extremely low probability of occurrence places it outside of Hydro's planning consideration, particularly given the near term in-service of the LIL and ML.

Finally, as discussed in Section 7.3.4, Hydro felt it appropriate to consider the impact of a one year delayed in-service for TL267. Table 19 shows that for the majority of cases considered this would result in EUE in excess of Hydro's planning criteria. Further, the two cases that do not violate planning criteria are, in fact, within 2 MWh of violation. These results highlight the reliability benefit that the completion of TL267 will provide for the IIS and further support Hydro's efforts to aggressively mitigate potential risk on this project, for example placing towers by helicopter.

Table 19 - Impact of one year delay in TL267 in-service on EUE[26]

2017-18 P90 Analysis						
Case	Fully Stressed Reference Case	Sensitivity Load Projection I	Sensitivity Load Projection II	Sensitivity Load Projection III	Sensitivity Load Projection IV	Sensitivity Load Projection V
HRD DAFOR	Expected Unserved Energy (MWh)					
14%	299	299	327	332	358	358
15%	362	362	395	401	432	432
20%	806	806	876	889	952	952
	Expected Customer Outage Hours					
14%	49,800	49,800	54,500	55,400	59,800	59,800
15%	60,200	60,200	65,800	66,800	72,100	72,100
20%	134,300	134,300	146,000	148,100	158,800	158,800

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000

[26] Note that LOLH is not provided for this analysis as the Strategist system model does not model changes in transmission line constraints. Hydro continues to investigate the suitability of Strategist and other modelling software to model its system at a higher level resolution. Note that EUE is a measure of transmission system capability and given that the delayed in-service of TL267 will result in continued transmission constraints for the IIS, it remains the most appropriate measure for evaluating Hydro's supply adequacy for this particular analysis.

8.0 Conclusion

Hydro has conducted an assessment of its overall asset health and a subsequent risk assessment of its ability to meet Island Interconnected System energy and demand requirements until the expected interconnection with the North American grid. It is important to note that the scheduled in-service of the Labrador Island Link and availability of recall energy in excess of Labrador requirements to the IIS will result in sufficient generation to meet system peak demand requirements and satisfy system planning criteria. The scheduled in-service of the Maritime Link and the access it provides to the North American grid will further bolster IIS reliability.

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 conducted a thorough assessment of its assets and determined reasonable projection for availability metrics. Hydro will continue to evaluate the appropriateness of DAUFOP in its evaluation of gas turbine availability. Further, Hydro has revised its demand forecast and constructed five sensitivity demand forecasts. Hydro concludes that once TL267 is placed in service, EUE is within Hydro’s planning criteria for all forecasts considered. Should the in-service of TL267 be delayed such that TL267 is not available for the winter 2017-18 peak, Hydro concludes that there is risk of EUE in excess of planning criteria. As such, the in-service of TL267 remains Hydro’s priority focus in terms of improving system reliability for customers until interconnection to the North American grid is achieved.

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 1.

Table 1 – P50 Peak Demand Forecast

Base Case Winter Demand Forecast					
	P50				
	2017/18	18/19	19/20	20/21	21/22
Customer Coincident Demand (MW)	1677	1672	1664	1652	1632
Transmission Losses (MW)	49	49	49	49	49
Station Service (MW)	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1750**	**1745**	**1736**	**1724**	**1705**

Notes:

Differences in totals vs addition of individual components due to rounding

Appendix B

Island Generation Supply – Gross Continuous Unit Ratings (T-093)

Island Interconnected System
Generation Supply Table

Unit Name	Turbine Rating (MW)	Generator Rating MVA	Generator Rating Power Factor	Nameplate Rating (MW)[1]	Adjustment (MW)	Gross Continuous Unit Rating (MW)
Bay d'Espoir Unit 1	80.6	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 2	80.0	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 3	80.0	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 4	80.0	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 5	80.6	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 6	80.6	85.0	0.90	76.5		76.5
Bay d'Espoir Unit 7	154.4	172.0	0.90	154.4		154.4
Total Bay d'Espoir Plant				613.4		613.4
Cat Arm Unit 1	68.5	75.5	0.95	68.5	(1.5)	67.0
Cat Arm Unit 2	68.5	75.5	0.95	68.5	(1.5)	67.0
Total Cat Arm Plant[2]				137.0		134.0
Hinds Lake	77.3	83.3	0.90	75.0		75.0
Granite Canal	40.0	45.0	0.90	40.0		40.0
Paradise River	8.2	8.9	0.90	8.0		8.0
Upper Salmon	86.0	88.4	0.95	84.0		84.0
Mini Hydro				1.4	(1.4)	0.0
Total NLH Owned Hydro				**958.8**		**954.4**
Holyrood Unit 1[3]		194.4	0.90	170.0		170.0
Holyrood Unit 2[3]		194.4	0.90	170.0		170.0
Holyrood Unit 3[3]		185.0	0.85	150.0		150.0
Total NLH Owned Thermal				**490.0**		**490.0**
Hardwoods GT[4]		63.3	0.85	50.0		50.0
Stephenville GT[4]		63.5	0.85	50.0		50.0
Holyrood CT				123.5	-	123.5
Holyrood Diesels[5]				12.0	(2.0)	10.0
St. Anthony Diesel Plant				9.7		9.7
Hawkes Bay Diesel Plant				5.0		5.0
Total NLH Owned Standby				**250.2**		**248.2**
Total NLH Owned				**1,699.0**		**1,692.6**
Star Lake				18.0		18.0
Rattle Brook[6]				4.0	(4.0)	-
CBPP Co-Gen[7]		18	0.85	15.3	(7.3)	8.0
Nalcor Grand Falls and Bishop's Falls[8]				95.6	(32.6)	63.0
Nalcor Buchans[8]				1.9	(1.9)	-
St. Lawrence Wind[9]				27.0	(27.0)	-
Fermeuse Wind[9]				27.0	(27.0)	-
Vale Capacity Assistance[10]				7.6	-	7.6
Total NLH Purchases				**196.4**		**96.6**
Total NLH System Supply				**1,895.4**		**1,789.2**
Newfoundland Power (Hydro)[11]				96.2	(19.8)	76.4
Newfoundland Power (Standby)[11]				41.5		41.5
Total Newfoundland Power Owned[12]				137.7		117.9
Total NLH and NP System Supply				**2,033.1**		**1,907.1**
Deer Lake Power Frequency Converter[13]				18.0	-	18.0
Deer Lake Power 60 Hz				81.1	-	81.1
Total Deer Lake Power Owned				99.1		99.1
Total Island Supply[14]				**2,132.2**		**2,006.2**

Revision: 7
Date: January 26, 2017

Island Interconnected System

Generation Supply Notes

Notes:

1. Unless otherwise noted, this is the minimum of the turbine rating or the generator rating at rated power factor.
2. Units at Cat Arm are adjusted as a plant generation of 134 MW is the maximum that can be sustained based on experience.
3. Ratings of the Holyrood units based on long standing published values. To determine net generation subtract station service of 24.5 MW (when all units are operating).
4. The units were permanently de-rated to 50 MW at the end of 2012.
5. Holyrood black start, 12 MW diesels. In present configuration 10 MW is available to the grid for peaking power.
6. No peaking capability assumed for the Rattle Brook Unit (only the current day's generation). Generation output will fluctuate depending on available inflows.
7. Generation output will fluctuate when Capacity Assistance arrangements are in place , depending on mill stem requirements. See note 14 below for further details. Generation can be reduced significantly when a large amount of load is curtailed. Otherwise, 8 MW is assumed on peak except for the current day when current day generation is used.
8. Nalcor Grand Falls, Bishop’s Falls and Buchans nameplate data taken from Statistics Canada survey data.
9. No peaking capability assumed for the wind generation (only the current day's generation). Generation output will fluctuate based on the wind levels.
10. Vale capacity assistance is adjusted for the current winter period based on the tested amount.
11. These are the generation capacities indicated by Newfoundland Power in "Maximum Load Rating" column of their daily generation status reports.
12. Overall Newfoundland Power generation adjusted to the current cost of service credit amount . Water adjustments are done separately on an operational basis.
13. Includes 60 Hz generation (DLP G1-7) and the 60 cycle output of the CBPP frequency converter.
14. Available reserves are calculated in consideration of generation supply capability and the load forecast which, during the winter period, is adjusted for load reduction strategies such as customer load interruption (under contractual arrangements) and system voltage reduction.

Appendix C

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"

Case I: Stephenville and Hardwoods GT UFOP = 30%

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	139	134	121	108	88
15%	168	161	147	131	107
20%	371	357	327	292	239
	Expected Customer Outage Hours				
14%	23,200	22,200	20,200	18,100	14,900
15%	27,900	26,900	24,400	21,700	17,800
20%	61,900	59,600	54,400	48,700	39,800
	LOLH				
14%	2.61	2.46	2.06	1.69	1.26
15%	3.02	2.84	2.39	1.96	1.46
20%	5.62	5.31	4.47	3.72	2.83

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Case II: Stephenville and Hardwoods GT UFOP = 50%

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	312	299	275	243	202
15%	374	358	330	292	243
20%	808	776	718	640	537
	Expected Customer Outage Hours				
14%	52,100	49,800	45,800	40,500	33,600
15%	62,300	59,600	55,100	48,600	40,500
20%	134,600	129,400	119,600	106,600	89,500
	LOLH				
14%	3.38	3.17	2.66	2.18	1.62
15%	3.88	3.66	3.07	2.52	1.88
20%	7.10	6.71	5.65	4.70	3.57

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Case III: Incremental 50 MW variation in peak demand versus the forecast for 2019-20 through end of study period

P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	112	108	243	216	180
15%	136	130	292	259	217
20%	302	290	632	565	476
	Expected Customer Outage Hours				
14%	18,800	17,900	40,400	35,900	30,000
15%	22,500	21,800	48,800	43,200	36,100
20%	50,300	48,300	105,400	94,300	79,500
	LOLH				
14%	2.27	2.13	3.23	2.70	2.06
15%	2.63	2.47	3.69	3.09	2.37
20%	4.93	4.66	6.54	5.54	4.32

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80