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January 26, 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: **Cheryl Blundon**
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Energy Supply Risk Assessment Updated – Revisions

Due to a mislabel in Table 6 in the Energy Supply Risk Assessment Report filed November 30, 2016, the labels associated with Stephenville and Holyrood should have been reversed. Enclosed please find the following revised Appendix A (Revision 1) page 5 of 5.

Hydro trusts that you will find the enclosed to be in order and satisfactory. Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/lb

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 Limited

	Electrical
REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador JENNIFER M. WILLIAMS SIGNATURE Nov 30, 2016 DATE NEWFOUNDLAND & LABRADOR	Mechanical
	Civil
	Protection & Control
REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador RENEE E. HODDER Renee E Hodder SIGNATURE Nov 30, 2016 DATE NEWFOUNDLAND & LABRADOR	Transmission & Distribution
	Telecontrol
	System Planning

ENERGY SUPPLY RISK ASSESSMENT

November 30, 2016

newfoundland labrador hydro
a nalcor energy company

1.0 Executive Summary

Newfoundland and Labrador Hydro (Hydro) has conducted a comprehensive risk assessment of its ability to meet Island Interconnected System (IIS) energy and demand requirements until the expected interconnection with the North American grid. This report builds on concepts and analysis presented in Hydro's initial energy supply risk assessment, filed with the Board of Commissioners of Public Utilities Board (the Board) on May 27 2016.[1]

This updated Energy Supply Risk Assessment is intended to:

1. Discuss the reliability of Hydro's existing generation assets, including the thermal generation assets at the Holyrood Thermal Generating Station (Holyrood), the gas turbines at Hardwoods and Stephenville, and Hydro's hydraulic generating facilities;
2. Determine expected reliability for these assets through to the interconnection period;
3. Determine Hydro's ability to meet its demand requirements given the projected reliability of these assets;
4. Consider alternative load growth scenarios and Hydro's ability to meet the associated change in forecast demand; and
5. Provide alternatives and options to mitigate exposure, if required.

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

From a demand perspective, Hydro has reviewed the reliability of its generation assets and determined that for Hydro's P90 peak demand forecast, expected unserved energy (EUE) does not exceed planning criteria in both the Expected and Fully Stressed Reference cases. Potential for EUE in excess of planning criteria does exist for winter 2016-17 in two of the sensitivity

[1] http://pub.nl.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/From%20NLH%20-%202015-2019%20Energy%20Supply%20Risk%20Assessment%20-%202016-05-27.PDF

demand forecasts considered. This is mitigated in subsequent winters by the in-service of the third 230kV transmission line from Bay d'Espoir to the Avalon Peninsula (TL267).

Additionally, Hydro continues to evaluate and budget appropriate investment in Holyrood and other plant assets. Finally, Hydro is in the late stages of negotiations to secure additional curtailable arrangements on the Avalon Peninsula to ensure continued delivery of safe, reliable power to its customers through to interconnection.

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2.0 Introduction

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

> *A report by November 30, 2016 on a comprehensive review of the energy supply for the Island Interconnected system as recommended by Liberty in its report dated August 19, 2016, that considers all risks and provides a risk-based recommendation on the need, timing and amount, if any, for additional pre-Muskrat Falls supply. This report shall include all current information on the load forecast and the status of generating units and shall address specifically the condition of the thermal units at Holyrood, the combustion turbines at Hardwoods and Stephenville and the Bay d'Espoir Penstock 1.*

This report provides the Board with the analysis regarding Hydro's ability to supply customers, considering asset reliability and generation supply in terms of both energy and capacity, until the expected interconnection with the North American grid. This report also provides information regarding Hydro's supply risk should the interconnection be delayed through winter 2019-20.

The Energy Supply Risk Assessment:

1. Provides an analysis of the reliability of Hydro's existing generation assets, including the thermal generation assets at the Holyrood Thermal Generating Station (Holyrood), the gas turbines at Hardwoods and Stephenville, and Hydro's hydraulic generating facilities by examining:
    - Recent historical generating asset reliability issues and the resolution to those issues;
    - Current equipment status for; Penstock 1 at Bay d'Espoir, the Holyrood thermal units, and for the Hardwoods and Stephenville gas turbines; and

- Analysis of recent Derated Adjusted Forced Outage Rate[2] (DAFOR) and Utilization Forced Outage Probability[3] (UFOP) results, as well as consideration of investments and improvements made to generating assets.

2. Presents the near term[4] DAFOR for the hydraulic and Holyrood units and UFOP for the gas turbines to be used for planning purposes;
3. Discusses Hydro's ability to meet its demand requirements given the projected reliability of these assets;
4. Considers alternative load growth scenarios and Hydro's ability to meet the associated change in forecast demand; and
5. Provides alternatives and options to mitigate exposure, if required.

3.0 Island Interconnected System Overview

Hydro is the primary generator of electricity in Newfoundland and Labrador. The utility delivers safe, least-cost, reliable power to utility, industrial, residential and commercial customers throughout the province. Hydro's statutory mandate is provided in subsection 5(1) of the *Hydro Corporation Act, 2007*[5] 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

[2] DAFOR is the Derated Adjusted Forced Outage Rate. It is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time. This measure is used for both the hydraulic and Holyrood generating assets.
[3] UFOP is the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required, It is used to measure performance of standby units with low operating time such as gas turbines.
[4] Near-term includes operation up to interconnection with the North American grid.
[5] *Hydro Corporation Act, 2007*, SNL 2007, c.H-17.

activities include the operation and maintenance of over 3,500 kilometers of transmission lines and 3,400 kilometers of distribution lines. Hydro also 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

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, two parallel 230 kV lines, TL202 and TL206, 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.

Figure 1 - Hydro's Generation and Transmission Infrastructure

3.2 Generation and Transmission Infrastructure

After integration of the Muskrat Falls Project assets[6], the IIS will have two interconnections to the North American grid via the Labrador Island Link (LIL) and the Maritime Link (ML). Further, the completion of a third 230 kV transmission line, from Bay d'Espoir to the Avalon Peninsula (TL267), 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.

[6] 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 bases its generation supply planning decisions on its P90 peak demand forecast.[7] The P90 peak demand forecasts reflects the associated increase in demand over the normalized peak demand forecast resulting from instances of severe wind and cold. In those instances, the actual peak will exceed the normalized, or P50, figure. The development of the P90 peak demand forecast is an extension of Hydro's regularly prepared system operating load forecast.

Hydro uses a weather normalized forecast as the basis for its system operating load forecast. This 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 model allows Hydro to forecast expected or average system energy requirements for specific time intervals, as well as assess the expected peak demand as part of its operating load forecast.

Both the P50 and the P90 peak demand forecast are important measures for Hydro when assessing system adequacy as the P50 forecast is the basis for the system operating load forecast and development of Hydro's energy forecast while the P90 forecast allows Hydro to assess its ability to reliably supply customers in instances of extreme weather conditions.

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

[7] 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.

been reviewed several times and found to be acceptable, 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.[8]

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

Additionally, as discussed in *Hydro's Response to the Phase I Report by Liberty Consulting* (the Hydro Reply),[10] 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.

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;

[8] 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.

[9] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Thermal Generating Station) is based on energy capability adjusted for maintenance and forced outages.

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

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

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

Through correlation of LOLH and EUE,[11] it was determined that 300 MWh of EUE is approximately equivalent to an LOLH of 2.8.

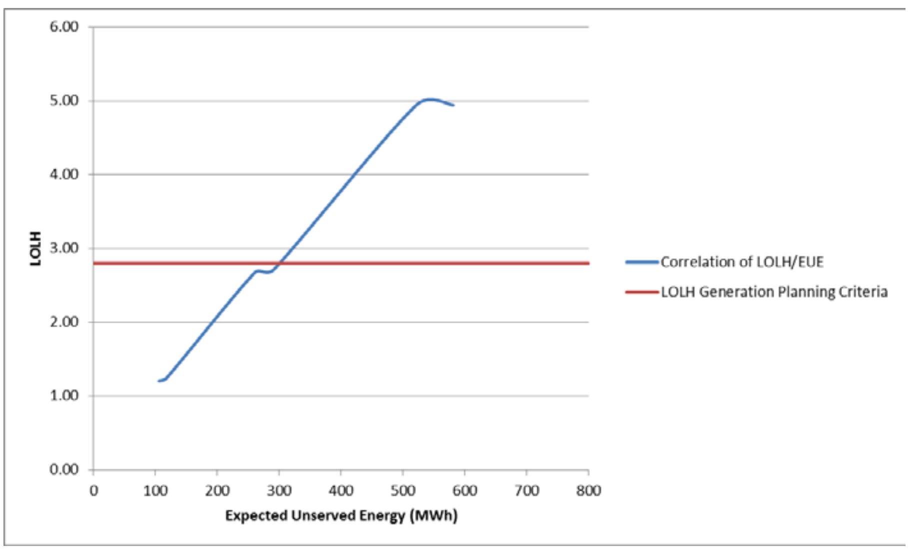

Figure 3 – Illustration of EUE vs LOLH

[11] 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.

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 the LOLH calculations (Hydro's "*Rolling 12 Month Performance of Hydro's Generating Units*" report). The most recent report was submitted on October 14, 2016, for the quarter ending September 20, 2016. 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 over the past two years.

At the time of the filing of this report, several generating units are in the final stages of being placed back into service following annual or planned major work, with those units expected to be back in-service in less than a week. Hydro's Winter Readiness Update due to the Board on December 7, 2016, will include the status on these units. This current report discusses the broader ability to meet energy and demand over this coming winter season, as well as the near term years.

5.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro reviewed its recent years' reliability history of generating units to ensure repetitive 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 following provides 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:

1. five areas of discussion for its hydraulic facilities (Bay d'Espoir Penstock 1, Paradise River plant, lightning, frazil ice, and Bay d'Espoir Unit 7 vibration);
2. four areas of discussion for its thermal facilities (unit boiler tubes, variable frequency drives, air flow limitations, and Mark V system); and
3. four areas of discussion for its gas turbines (fuel lines, fuel valve failures, snow doors at Hardwoods, and clutch proximity switches).

5.1.1 Hydraulic

i. 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. In May 2016, a leak was detected in the penstock when water was found to be running alongside the penstock. The leak was excavated and investigated by Hydro, in consultation with a penstock engineering consultant. The cause of the leak was attributed to a welding error when the penstock was constructed and repairs were made to the weld in the penstock. No other visible defects, active leaks, or other deficiencies were detected. The penstock was returned to service June 3, 2016.

Penstock 1 developed a second leak, which was discovered in September 2016. Following inspection, it was determined that this second leak also resulted from a weld in poor condition. At this point, Hydro engaged welding expertise to further investigate the broader condition of the full penstock welded connections. The investigation resulted in a major project requiring the removal and replacement of approximately 700 m of welds in the uppermost portion (approximately one quarter) of the penstock. This work is now complete and the penstock has been returned to service including Units 1 and 2.[12]

An in-depth root cause investigation, including metallurgical testing, is underway to determine why the welds deteriorated in the upper portion of the penstock. Pending the results of this investigation, Hydro will be adjusting its maintenance and investment plans, as required, to ensure improved reliability for these assets. The results of the root cause investigation will be communicated to the Board. Based on the outcomes of the investigation of Penstock 1 at Bay d'Espoir, Hydro will put plans in place to undertake further inspections and refurbishments, as appropriate.

The detection and subsequent repair of the first weld failure in Penstock 1 prompted an accelerated timeline for penstock engineering inspections. Hinds Lake was inspected in Fall 2016 with the penstock and welds found to be in good condition, as was the penstock generally. Penstock 2 and 3 at Bay d'Espoir will be inspected in 2017. All remaining penstocks will have engineering inspections completed between 2018 and 2020. Hydro is coordinating the timing of the inspections with other work requiring the penstocks to be dewatered.

ii. Paradise River plant

Paradise River is an 8 MW plant located on the Burin Peninsula. The plant had been experiencing an increasing number of unit trips through 2016 in comparison to previous years. From January to mid-November 2016, the plant has experienced almost 30 unit trips, compared to 11 in 2015 and 4 in 2014, respectively. For a high proportion of the trips in 2016, no cause could be determined despite a thorough analysis and inspection at the plant.

Hydro expanded the review team, incorporating expertise from across the organization, to complete a more extensive review to determine the cause of the repeated trips.[13] A cross

[12] Exterior penstock clean up and site restoration continues on this project. This will be concluded through December and will not affect penstock availability.

[13] It has been hypothesized that the distribution line into which the plant is connected may be experiencing some system disturbances. Paradise River plant is connected to the Island Interconnected System via a distribution line,

departmental set of actions were identified and investigated. One of the key actions was to work with Newfoundland Power to replace a recloser in the Monkstown substation. The existing recloser, while functioning, was of an older vintage. Due to technical limitations, the device could not provide the monitoring Hydro needed in order to query historical data, which is required to properly investigate unclassified unit trips. A modern recloser, equipped with systems to provide for improved data mining and troubleshooting, was installed mid-October. Since the installation of the new recloser, there have been no trips of the plant with an undetermined cause. This is a significant improvement over the frequency experienced prior to recloser replacement. Hydro will continue to monitor this situation closely to determine if further action is required.

iii. 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), are susceptible to tripping during lightning strikes to the line. 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 to 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, wherever possible, will take action to reduce the overall loading on the plant to a level below that which would require underfrequency load shedding if a trip were to occur (typically 50 MW or less). This practice has

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as opposed to a dedicated transmission line.

helped Hydro better manage the IIS during lightning events, resulting in a positive impact on customers' reliability by avoiding a number of underfrequency events.

iv. 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 ice type 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 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 opportunely located. This change provides improved data, enabling operators to better respond to frazil icing situations by making dispatch changes.

Hydro also optimizes the trashrack[14] 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. Based on the operators' assessment of these parameters, in conjunction with system conditions, unit dispatch is optimized to allow solid ice cover to form, further reducing frazil ice risk.

[14] 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.

v. 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 during restarting 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.

5.1.2 Thermal

i. Unit Boiler Tubes

The three thermal generating units at Holyrood Thermal Generating Station (Holyrood) each have a boiler that contains reheater tubes. The primary purpose of the lower reheater tubes is to increase the final temperature of the low pressure superheated steam being fed to the intermediate and low pressure turbine sections. Steam is contained inside the tubes and the gases from the boiler fire pass over the tubes and transfer heat energy to the tube which transfers heat energy to the steam.

The lower reheater sections of the boilers for Units 1 and 2 experienced failures in January and February 2016. The most critical reheater tubes were replaced immediately. To minimize the likelihood of customer impact, unit de-ratings were put in place prior to the scheduled annual unit outages. The de-ratings maintained the units at lower load and therefore less prone to tube leaks. This approach minimized the risk of tube failures that would require a unit to be removed from service for an unplanned outage. All remaining lower reheater tubes have since been replaced and the de-rating on these units has been lifted.

In response to the reheater tube failures, 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[15] observed since 2010 in each boiler section, the operating pressures and temperatures, and the remaining expected creep[16] life for the superheater and reheater tubes. The initial conclusions from this study indicated no concerns for the 2016/17 operating season for Unit 1 and Unit 2, making these units available for full load operation. Boiler maintenance outages will be completed in 2017 for these units, including tube thickness surveys to confirm future operating season unit output. Hydro will continue to proactively monitor and replace tubes as required during these outages.

Two sections of the boiler for Unit 3 contained tubes considered to be at the end of life due to creep calculations. These calculations were performed using the thinnest observed readings since 2010 from historical thickness data and design tube operating temperatures provided by the boiler original equipment manufacturer (OEM) Babcock & Wilcox (B&W). Based on these calculations, AMEC recommended a de-rating of 10% to mitigate the risk of tube failures for the 2016-2017 operating season. This recommendation was provided on August 8, 2016.

Hydro took an additional outage on Unit 3 in September 2016 and contracted B&W to complete a specialized Non-Destructive Evaluation inspection of the two areas of concern noted by AMEC's calculations. The B&W inspection results indicate that the operating temperatures of the tubes were significantly less than calculated and that the tubes have many years of creep life remaining. AMEC then reviewed the results of this inspection and concurred with B&W. AMEC provided a technical opinion in October 2016 that the 10% de-rate is not required for the 2016-2017 operating season. Therefore, Unit 3 is also available for its full rating of 150 MW for this coming winter season. As with Units 1 and 2, Hydro will continue to proactively monitor and replace tubes.

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[15] Failure is typically experienced in thinning tubes.

[16] 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.

From a reheater tube perspective, these units are considered available for full load operation; 170 MW on Units 1 and 2, and 150 MW on Unit 3.

To confirm operating output for future seasons, Hydro is planning to undertake additional specialized inspections in other sections of the Unit 3 boiler. Also, by the end of 2016, AMEC will have completed calculations of threshold tube thickness numbers for various tube sections within the boiler for Unit 3. This will provide planned replacement guidelines based on creep concerns and internal pressure that Hydro can then use when completing future inspections to ensure proactive identification and replacement of identified tubes. If required, Hydro will complete targeted replacements annually.

ii. 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. There have, however, been operational issues with the VFDs resulting in unit trips and reduced unit output.

Throughout 2016, Hydro has 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 have been modified and additional actions taken to improve reliability. These modifications and actions include:

- Control power for the VFD processors and power for the cooling fans mounted on the VFDs was moved from a station service feed to a more stable, unit service feed, which is not impacted by external events provided that the generating unit remains on line.
- Cooling fan assemblies were upgraded with more robust louvres, as the previous ones had experienced failures and the failed sections of louvre material posed a short circuit risk inside the drive cabinets.

- Power cell single phase connection clips were replaced, as their original design was not as heavy duty as operational performance indicated was required.
- Control boards were updated to the latest, improved firmware.
- Full onsite annual inspection was conducted by Siemens technical service representatives during the 2016 unit maintenance outages.
- A full complement of recommended and optional spare parts was procured and stocked on site.
- Full engineering review of the installation and operation of the VFDs was conducted onsite by a team of Siemens design and testing engineers.

Through these extensive investigations and thorough analysis, the actions Hydro has undertaken to date were confirmed by Siemens as appropriate and no additional remedial actions were recommended.

iii. Air Flow Limitations

Holyrood Units 1 and 2 boilers have experienced air flow limitations since 2015, with these limitations restricting output by as much as 15 MW. Appropriate air flow is required to provide enough air for combustion, thus enabling full output from the units. Unit 3 has not experienced air flow limitations similar to those experienced on Units 1 and 2.

To address the air flow limitations, Unit 1 and 2 boiler tuning was planned for Fall 2016 after the lower reheater sections had been replaced during the annual maintenance outage on both units. Boiler tuning was completed on Unit 2 and the unit's full capacity of 170 MW was made available to the IIS. Based on the results of the Unit 2 tuning exercises, Hydro concluded the root cause of the air flow issues on both units is the additive effect of fouling[17] through various

[17] 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.

sections of the ducting, boiler, air heaters and flues, air heater leakage, as well as a need for boiler tuning.

In addition to the boiler tuning to establish maximum unit output, additional measures were taken during the annual planned outage on Unit 1 to improve its air flow. This included the replacement of a section of steam coil air heater, economizer washing, and air heater basket cleaning. Additionally, an air heater representative was brought in from the OEM to inspect components and verify seal condition. The result of this work was the restoration of the Unit's output to 170 MW.

With respect to Unit 1, Hydro expects that the generation output may deteriorate somewhat as the normal fouling continues over the 2016-17 operating season. It is evident that more extensive cleaning will be required, particularly in the economizer and air heaters. This work is planned as a priority for 2017. As well, Hydro is planning air heater upgrades in 2017 that will replace parts and reduce leakage. Until the 2017 scheduled annual outage, Hydro will take action to reduce fouling in the problem sections through more frequent soot blowing and off-line air heater washing, as appropriate. Similar problems were noted to a lesser extent on Unit 2, and subsequently corrected.

Finally, as part of the 2017 boiler outages, additional work will be completed to further clean the air and gas paths, thereby improving air flow through both units.

iv. Mark V system

A governor system controls the steam flow into a turbine and maintains consistent unit speed. The governor control system (General Electric (GE) Mark V) for Units 1 and 2 were installed in 2003 and 1999, respectively. GE moved the Mark V system into the obsolete phase of its lifecycle at the end of 2014. At that time, Hydro entered a revitalization agreement with GE to increase the reliability of this obsolete system. Given the expected remaining life of Holyrood at the time, this option was determined more prudent than upgrading the governor control system. To further mitigate risk, Hydro bolstered its stock of spare Mark V cards, given new cards were no longer being produced.

During 2016, several hardware card failures have either caused a trip of a unit or kept a unit from returning to service. Through its stock of spares and the revitalization agreement, Hydro has been able to remedy these faults quickly. GE has made several site visits and continues to actively monitor the health of the Mark V system. This includes an in depth review of the quantity and condition of all parts and related equipment on site by a Mark V service technician.

This assessment by GE will be complete before the end of 2016. Any resulting remedial actions, if required, will be completed to increase confidence in this system for the winter season. Hydro and GE are working towards an agreement for additional support for the Mark V system. Hydro is also reconsidering the merits of upgrading or replacing the Mark V system to improve the reliability of Holyrood Unit 1 and Unit 2.

5.1.3 Gas Turbines

i. Fuel Lines at both Stephenville and Hardwoods

Hydro has experienced fuel line leaks at both the Stephenville and Hardwoods gas turbines in recent years resulting from quality control deficiencies. The impacts of these leaks have ranged from temporary unit unavailability to longer unit unavailability as a result of fire within the units. The fires were investigated, and based on the fire investigation, the quality control issues were determined and all fuel lines were required to be replaced with service-appropriate lines. New, appropriately designed and quality control tested replacement lines were ordered and installed in all units in 2015 which have eliminated issues with fuel line leaks to date.

ii. Fuel valve failures at Hardwoods

Hydro has 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 a specific issue with the valve. By moving the fuel supply to the valve to 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.

However, there has been one additional valve failure and the valve has been returned to the OEM for analysis. It is expected that this failure is the result of wear and tear unrelated to the previous issue. Multiple spares are held for these valves in the event of failure. Valve failure is generally not catastrophic in nature, but typically will result in a failed start. In the event of valve failure, the replacement time is roughly several hours.

iii. Snow doors overhaul/upgrade at Hardwoods

The Hardwoods gas turbine has snow doors that prevent snow from entering the unit itself, which must remain open during operation. Several different issues with the doors contributed to reduced reliability for Hardwoods this past winter.

The existing snow door design and operation would result in failures caused by proximity switch mounting, control wiring, bearings, and freezing due to moisture. Hydro investigated the issues and determined an upgrade would provide a more reliable design.

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 bearings. This upgrade is now complete and Hydro expects this upgrade will provide for improved reliability of the unit in the winter 2016-17 operating season.

iv. Clutch proximity switch at Hardwoods

The clutch proximity switch provides an indication of whether the clutch is engaged or disengaged. Multiple trips of End B of the Hardwoods unit were the result of inaccurate indication of clutch position. Hydro investigated recurring issues associated with the clutch proximity switch in conjunction with the OEM.

The OEM was consulted and reviewed the system during a site visit. The OEM recommended a change in location and adjustment of the switch, which was implemented in 2014. The switches are regularly checked and adjusted as required. Changes made have resulted in a reduction of unit trips.

5.2 Specific Equipment Status Review

Table 1 provides the status[18] of the condition of the thermal units at Holyrood, the gas turbines at Hardwoods and Stephenville, and the Bay d'Espoir Penstock 1.

[18] Refer to Section 5.0. Generation unit status will be discussed in the Winter Readiness Report due December 7, 2016.

Table 1 – Specific Equipment Status Review

Asset	Capacity to IIS (MW)	Comments
Bay d'Espoir Penstock 1	153	Exterior penstock clean up and site restoration continues on this project. This will be concluded through December and does not affect penstock availability.
Holyrood Unit 1	170	Hydro intends to typically load these units to a maximum of 150 MW
Holyrood Unit 2	170	
Holyrood Unit 3	150	Hydro intends to typically load this unit to a maximum of 135 MW
Hardwoods End A	50	Hydro will keep and maintain the 19 MW loaner engine as a further mitigating measure in the event of a turbine failure requiring replacement of any end at either location. Hydro has inspected the loaner engine and will perform planned maintenance as required to ensure its availablity. Hydro is working to mitigate any time that the unit would not be available during the maintenance period. Hydro also notes that the practice of staffing the combustion turbines in advance of system requirements with both operators and skilled-trades staff provides for the opportunity to work through issues that may arise, and contributes to a better response and restoration time. Hardwoods and Stephenville engines have passed factory acceptance testing and are currently being installed and commissioned.
Stephenville End A	50	

5.3 Selection of Appropriate Performance Ratings

5.3.1 Consideration of Asset Reliability in System Planning

Hydro's asset reliability is a critical component in determining its ability to meet the System Planning criteria identified in Section 4. 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 2 summarizes the projected availability for Hydro's generating assets considered in the assessment of supply adequacy. For detailed information on each parameter, please refer to section 5.1.

Table 2 – 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%

Hydro has determined appropriate DAFORs for both Holyrood thermal units and for the Hydraulic Units across the province, as well as appropriate UFOPs for consideration in the evaluation of supply risk. These ratings are focused on the near term, as opposed to long term planning assumptions. Recent historical performance, as well as recent improvements and investments made on these units, was considered in developing appropriate DAFOR and UFOP ratings for the study period. For information regarding the development of these metrics, please refer to Appendix A.

Hydro also notes that there are instances throughout the annual winter operating season that require pro-active maintenance, often on condition basis. These maintenance activity requirements are monitored and scheduled when system conditions allow. An example is an air heater wash at Holyrood. These heaters can generally stay in service between 2 and 3 months a season, but toward the end of that 2-3 month period, unit output will deteriorate and maintenance is required to reestablish the unit output. Hydro completes these types of maintenance activities when system reserves allow.

6.0 Load Forecast

Hydro's load forecast 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 rural service territory.[19] 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, the Holyrood Thermal Generation Station 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.

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 demand and an associated incremental 10 MW of transmission losses over the P50 demand forecast for a total of 70 MW.[20]

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 3. Information on Hydro's P50 forecast can be found in Appendix B.

[19] 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.

[20] 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 over 30 MW of load on the Avalon Peninsula. The increase in transmission losses is therefore attributed to both factors.

Table 3 – Base Case Winter Demand Forecast

Base Case Winter Demand Forecast				
	P90			
	2016/17	17/18	18/19	19/20
Customer Coincident Demand (MW)	1712	1722	1720	1720
Transmission Losses (MW)	64	50	50	50
Station Service (MW)	24	24	24	24
Total Island Interconnected System Demand (MW)	**1800**	**1796**	**1793**	**1793**

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

6.1 Comparison to Forecast in Hydro's May 2016 Energy Supply Risk Assessment

The peak demand forecasts used in Hydro's initial Energy Supply Risk Assessment were based on customer demand forecasts available in March 2016. For ease of comparison, the P90 forecasts used in each assessment are provided in Table 4. The same analysis has been completed for Hydro's P50 forecast and is presented in Appendix B.

Table 4 – P90 Peak Demand Forecast Comparison

P90 Forecast Comparison												
	ESRA - May 2016				ESRA - November 2016				Change (MW)			
	2016/17	17/18	18/19	19/20	2016/17	17/18	18/19	19/20	2016/17	17/18	18/19	19/20
Customer Coincident Demand (MW)	1709	1733	1738	1745	1712	1722	1720	1720	3	-11	-18	-25
Transmission Losses (MW)	68	74	57	58	64	50	50	50	-4	-24	-8	-9
Station Service (MW)	24	24	24	24	24	24	24	24	0	0	0	0
Total Island Interconnected System Demand (MW)	**1801**	**1831**	**1819**	**1827**	**1800**	**1796**	**1793**	**1793**	**-1**	**-35**	**-26**	**-34**

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

Since the completion of the May Energy Supply Risk Assessment, there has been a decrease in the coincident demand forecast post 2016/17, largely associated with revised customer demand. The change in forecasted customer demand is attributable to the revised

Newfoundland Power load forecast (October 7, 2016).[21] The most notable change in transmission losses occurs in Winter 2017/18 due to the advancement of TL267, which will be in service for the Winter 2017-18 season. As noted in Section 5.1.2, the available capacity from Holyrood units has increased, resulting in a reduction in net power flow to the Avalon Peninsula. This increased generation on the Avalon Peninsula results in reduced transmission losses. There is no change in station service demand requirement.

6.2 Sensitivity Load Growth Scenarios

To ensure a robust assessment of risk, Hydro has developed three P90 sensitivity forecasts reflecting:

- Sensitivity Load Projection I - Stable utility demand: Assumes that in spite of the current forecast, which is for reduced energy requirements relative to 2015, 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; and
- 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.

The sensitivity forecasts are summarized in Table 5 below.

[21] Note that the trend changes in Newfoundland Power's load forecast provided to Hydro in October are supported by Hydro's own internal forecast models for this service territory based on the current economic outlook for the province.

Table 5 – Alternative Load Growth Scenarios

Alternative Load Growth Scenarios								
	Sensitivity II:				Sensitivity III:			
	2016/17	17/18	18/19	19/20	2016/17	17/18	18/19	19/20
Customer Coincident Demand (MW)	1721	1733	1732	1732	1724	1734	1731	1731
Transmission Losses (MW)	64	50	50	50	65	50	50	50
Station Service (MW)	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1809**	**1807**	**1805**	**1806**	**1812**	**1807**	**1805**	**1805**

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

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 system capability has increased over the capacity reflected in Hydro's Energy Supply Risk Assessment filed in May. The change in capability since the last filing results from the higher availability of the Holyrood units and the increased reservoir levels. Table 6 provides the expected system capability for 2017 through 2019. The capability indicated is well in excess of Hydro's forecasted system energy requirements.

Hydro continues to provide the Board with monthly updates regarding system hydrology in its Monthly Energy Supply Report.

Table 6 – System Capability (GWh)

	HTGS Capability (GWh)	Hydraulic and Purchases Capability (GWh)	**Total System Capability (GWh)**
2017	2,895	5,629	**8,524**
2018	2,895	5,629	**8,524**
2019	2,895	5,629	**8,524**

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

7.2 Transmission System Analysis

Transmission Planning analysis previously undertaken as part of Hydro's May 2016 Energy Supply Risk Assessment was revised to include the 12 MW of mobile diesel generation at Holyrood and the October 2017 in-service of TL267 in the base case assumptions. System capacities under various operating scenarios were quantified and exposures for unserved energy were investigated. Transmission planning analysis also determined the impact of the in-service of the Labrador Island Link and the Maritime Link, TL267, and the addition of 10 MW of curtailable load on Avalon Peninsula capacity. Resultant capacities are provided in Appendix C.

7.2.1 The Avalon Transmission System

Load 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;
- Wind Generation;[22] and
- 230 kV transmission lines TL203 and TL237 at Western Avalon Terminal Station.

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

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 contingencies including the loss of one of TL202, TL206, or one unit at Holyrood 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 P90 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, as presented in Appendix D, and the recommendations of Hydro's Asset Management team, as discussed in section 5.1.2. These ratings are summarized in Table 7 below.

Table 7 –Capacity for Holyrood Units

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

7.2.3.1 Loss of Multiple Holyrood Units

Due to transmission system constraints on the Avalon Peninsula, an Avalon load of 845 MW can be supported with Holyrood Units 1 and 2 out of service. With either Holyrood Units 1 and 3 or Units 2 and 3 out of service, a maximum gross Avalon load of 855 MW can be supported. 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 1685 MW, equating to a gross Avalon load of approximately 905 MW after the in service of TL267.

Similarly, a maximum gross Avalon load of 675 MW can be supported with three Holyrood units out of service. Once TL267 is placed in service, total Island Interconnected System capacity for three Holyrood units out of service is limited to approximately 1410 MW, equating to a gross Avalon load of approximately 755 MW. The above information is summarized in Appendix C.

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 EUE and reserve megawatt criteria of:

1. Thermal generation availability based on projected DAFORs and UFOPs;
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 2016-17 through Winter 2019-20 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 are 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.
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 Newfoundland & Labrador Limited is 10.8 MW.
8. Curtailable loads are as follows:
    - Corner Brook Pulp and Paper – 80 MW
    - Newfoundland Power – 9.9 MW (9 MW on the Avalon Peninsula)
9. Holyrood units are rated in accordance with Table 8.

Table 8 – 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 D).

7.3.2 Fully Stressed Reference Case

The Fully Stressed Reference Case is 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 2019-20.

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 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.

7.4 Results

EUE in excess of planning criteria for the Expected Case, Fully Stressed Reference Case, and the three sensitivity load projections is presented in Table 9. Based on the projected asset reliability discussed in Section 5.0, and demand forecasts discussed in section 6.0, neither the Expected Case, the Fully Stressed Reference Case, nor Sensitivity Load Projection I (the stable utility demand case) results in EUE in excess of planning criteria.

Both Sensitivity Load Projection II (the high industrial coincidence) and Sensitivity Load Projection III (the high utility coincidence) demand forecasts result in EUE in excess of planning criteria for the upcoming winter, Winter 2016-17, only. This EUE in excess of planning criteria is observed for these cases despite having a relatively low increase in demand forecast for Winter 2016-17 over the base case forecast, 9 MW and 12 MW respectively. The in-service of TL267 for winter 2017-18 more than mitigates any additional exposure for EUE in excess of planning criteria.

Table 9 – Summary of EUE Results

P90 Analysis				
Year	**2016/17**	**2017/18**	**2018/19**	**2019/20**
	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
Expected Case	-	-	-	-
Fully Stressed Reference Case	-	-	-	-
Sensitivity Load Projection I	-	-	-	-
Sensitivity Load Projection II	15	-	-	-
Sensitivity Load Projection III	24	-	-	-
	Incremental Annual Expected Outage Hours			
Expected Case	-	-	-	-
Fully Stressed Reference Case	-	-	-	-
Sensitivity Load Projection I	-	-	-	-
Sensitivity Load Projection II	2,500	-	-	-
Sensitivity Load Projection III	4,000	-	-	-

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

Reserve margins for the Expected Case, Fully Stressed Reference Case, and the three sensitivity load projections are presented in Table 10. No violations of reserve margin occur within the study period for any case considered.

Table 10 – Reserve Margin Analysis

Island Interconnected System P90 Demand Forecast Reserve Margin Analysis				
	Winter 2016-17	Winter 2017-18	Winter 2018-19	Winter 2019-20
Expected Reference Case				
A: IIS Forecast Peak Demand	1,800	1,796	1,793	1,793
B: Less Available Capacity Assistance (90 MW)	1,710	1,706	1,703	1,703
C: Capacity at Peak	2,009	2,009	2,119	2,119
Reserve Margin (MW) (C-B)	299	304	416	416
Reserve Margin (%)	17%	18%	24%	24%
Fully Stressed Reference Case				
A: IIS Forecast Peak Demand	1,800	1,796	1,793	1,793
B: Less Available Capacity Assistance (90 MW)	1,710	1,706	1,703	1,703
C: Capacity at Peak	2,009	2,009	2,009	2,009
Reserve Margin (MW) (C-B)	299	304	306	306
Reserve Margin (%)	17%	18%	18%	18%
Fully Stressed Reference Case with Sensitivity Load Projection I				
A: IIS Forecast Peak Demand	1,800	1,804	1,803	1,802
B: Less Available Capacity Assistance (90 MW)	1,710	1,714	1,713	1,712
C: Capacity at Peak	2,009	2,009	2,009	2,009
Reserve Margin (MW) (C-B)	299	295	296	297
Reserve Margin (%)	17%	17%	17%	17%
Fully Stressed Reference Case with Sensitivity Load Projection II				
A: IIS Forecast Peak Demand	1,809	1,807	1,805	1,806
B: Less Available Capacity Assistance (90 MW)	1,719	1,717	1,715	1,716
C: Capacity at Peak	2,009	2,009	2,009	2,009
Reserve Margin (MW) (C-B)	290	293	294	293
Reserve Margin (%)	17%	17%	17%	17%
Fully Stressed Reference Case with Sensitivity Load Projection III				
A: IIS Forecast Peak Demand	1,812	1,807	1,805	1,805
B: Less Available Capacity Assistance (90 MW)	1,722	1,717	1,715	1,715
C: Capacity at Peak	2,009	2,009	2,009	2,009
Reserve Margin (MW) (C-B)	287	292	294	295
Reserve Margin (%)	17%	17%	17%	17%

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

8.0 Mitigation Alternatives

As discussed in Section 7.4, Sensitivity Load Projection II (high industrial coincidence) and Sensitivity Load Projection III (high utility coincidence) demand forecasts result in EUE in excess of planning criteria for winter 2016-17. That exposure is mitigated for subsequent winters by the accelerated in-service of TL267.

Given the temporary duration and the immediacy of the exposure for the winter of 2016-17, the appropriate option to mitigate the risk of EUE for the sensitivity demand forecasts is to secure additional curtailable Avalon Peninsula load to reduce the identified transmission exposure,.

8.1 Incremental Curtailable Load

As shown in Table 11, the securing of 10 MW of Incremental Curtailable Load on the Avalon Peninsula ensures no violation of planning criteria for any case considered.

Table 11 – Summary of EUE Results with 10 MW Incremental Curtailable Load

P90 Analysis with 10 MW Incremental Curtailable Load				
Year	**2016/17**	**2017/18**	**2018/19**	**2019/20**
	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
Expected Case	-	-	-	-
Fully Stressed Reference Case	-	-	-	-
Sensitivity Load Projection I	-	-	-	-
Sensitivity Load Projection II	-	-	-	-
Sensitivity Load Projection III	-	-	-	-
	Incremental Annual Expected Outage Hours			
Expected Case	-	-	-	-
Fully Stressed Reference Case	-	-	-	-
Sensitivity Load Projection I	-	-	-	-
Sensitivity Load Projection II	-	-	-	-
Sensitivity Load Projection III	-	-	-	-

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

Hydro is in the late stages of negotiations to secure additional curtailable arrangements on the Avalon Peninsula. While Hydro in unable to provide detailed information at this time, due to the commercial nature of these matters, Hydro has ascertained that the required level of curtailable demand does exist within its system and is working towards appropriate commercial terms with potential suppliers. Hydro will apply to the Board for approval of these agreements once negotiations are final.

9.0 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. This reflects a two-year in-service delay for both the Maritime Link and the Labrador Island Link. It is important to note that the scheduled in-service of either of these assets results in sufficient generation to meet IIS peak demand requirements and satisfy system planning criteria.

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. Further, Hydro has revised its demand forecast and constructed three sensitivity demand forecasts. Hydro concludes that until interconnection to the North American grid is achieved, there is some risk of EUE in excess of planning criteria for two of the sensitivity demand cases considered for winter 2016-17. For winter 2016-17, this risk can be fully mitigated, and EUE brought back within planning criteria, by the securing of 10 MW of curtailable load. For Winter 2017-18 and beyond, this risk is mitigated by the in-service of TL267.

Hydro is in the late stages of negotiations to secure additional curtailable arrangements on the Avalon Peninsula. While Hydro in unable to provide detailed information at this time, due to the commercial nature of these matters, Hydro has ascertained that the required level of curtailable demand does exist within its system and is working towards appropriate commercial terms with potential suppliers.

APPENDIX A

Analysis to support determination of DAFOR and UFOP

1.0 Hydraulic Units:

1.1 Review of Recent Performance

Hydro reviewed its recent hydraulic DAFOR actuals. Five year averages are presented in Table 1. As a means of comparison, the CEA average is provided. Hydro's generation planning Assumption is 0.9%.

Table 1 – Hydraulic DAFOR Actuals – Five Year Average

Five Year Average DAFOR		
	Hydro	CEA
2011-2015	2.2%	5.6%
2012-2016 (projected)	2.4%	Unavailable

1.2 Projected DAFOR for Study Period

In order to be appropriately conservative and reflect recent history, Hydro considered its hydraulic units as two groups – those at Bay d'Espoir in one group, due to the general common age, and the remaining units in a separate group, as they are all generally newer, with the oldest being 36 years old. The DAFORs were analyzed for the units within those groups and are presented in Table 2.

Table 2 – Projected Hydraulic DAFOR

Projected DAFOR	
Bay d'Espoir	3.9%
Other Hydraulic	0.7%

Hydro notes that both the projected 2012-2016 actual hydraulic plant DAFORs for Bay d'Espoir includes significant contribution of downtime at Penstock 1 due to the penstock leak. The proposed DAFORs for Bay d'Espoir also contemplates outages of duration that would be required to fix a leak and put the penstock back in service as discussed in 5.1.1 of Hydro's Energy Supply Risk Assessment.

2.0 Holyrood:

2.1 Review of Recent Performance

In Hydro's May 2016 Energy Supply Risk Assessment, a series of DAFORs, ranging from 10-24%, were considered. Since that time, considerable analysis and evaluation of the Holyrood units has been completed. Hydro's thermal plant DAFOR five-year averages are presented in Table 3. Given the boiler tube issues experienced at Holyrood this past winter season, 2016 data has been presented both as part of the projected 2012-2016 average and on its own. Additionally, Units 1 and 2 were de-rated to 120 MW during the first part of in 2016 to manage the risk of a tube failure associated with thinning boiler tubes. These derating were a major contributor to the 2016 thermal DAFOR, and as such, a projected DAFOR for 2016 exclusive of the derating has also been included. Hydro's Generation planning Assumption is 9.64%, with sensitivity analysis conducted at 11.64%.

Table 3 – Thermal DAFOR actuals

Five Year Average DAFOR	
	Hydro
2011-2015	14%
2012-2016 (projected)	16%
2016 only (projected)	19%
2016 only; Deration excluded	9%

2.2 Projected DAFOR for Study Period

To be appropriately conservative for the near term and reflect recent history, including investments made and assessments completed, Hydro selected a set of conditions that represent recent reliability issues at the plant. This methodology was used to determine a realistic DAFOR for the Holyrood plant for the coming winter and for near term seasons. These assumptions then formed the basis for the projection of a near term appropriate DAFOR for Holyrood. Hydro selected these conditions to reflect the potential and probable operating and equipment issues it should factor in to its projection of DAFOR for 2017 and future operating seasons.

a. Unit 1:
   i. Unit de-rated by 5 MW for six months, and de-rated 10 MW for remaining six months. This type of derating has occurred due to air flow limitations in the past.
   ii. A forced outage of 30 days during operating season as was experienced when the tubes underwent urgent replacement in winter 2016.
   iii. Eight outages of 24-hours during operating season. These types of outages are to address items such as exciter brush replacement or, an air heater wash, which can reach 48 hours.
   iv. A forced outage of five days. This type of outage has been experienced with the variable frequency drives for the forced draft fans or with the governor control system.

b. Unit 2:
   i. Unit de-rated by 5 MW for 12 months. This type of derating has occurred due to air flow limitations in the past.
   ii. A forced outage of 30 days during operating season as was experienced when the tubes underwent urgent replacement in winter 2016.
   iii. Eight outages of 24-hours during operating season. These types of outages are to address items such as exciter brush replacement or air heater wash, which can reach 48 hours.
   iv. A forced outage of five days. This type of outage has been experienced with the variable frequency drives for the forced draft fans or with the governor control system.

c. Unit 3:
   i. Forced outages of 30 days total during operating season. This could be two or three outages of smaller duration, and to be conservative, Hydro has included 30 days total.
   ii. Seven outages of 24-hours during operating season. These types of outages are to address items such as exciter brush replacement or air heater wash, which can reach 48 hours. Unit 3 operates in synchronous condenser mode and, as such, is not in generate mode for as many hours as Units 1 and 2. Therefore Hydro has allocated seven outages as opposed to eight in this calculation.

Hydro notes that Unit 3 can operate in synchronous condenser mode for a portion of the year and Hydro factors this in its planning assumptions; however, it does impact the DAFOR calculations. As per DAFOR methodology, hours operated in synchronous condense mode are not included in the DAFOR base hours calculation and therefore result in a higher DAFOR for Unit 3 when compared to Units 1 and 2, despite the unavailable hours in the conditions listed for Unit 3 are less than those listed for similar considerations for Units 1 and 2.

The projected DAFORs for both the individual units and the total plant based on all noted considerations are provided in Table 4.

Table 4 – Projected Thermal DAFORs

Projected DAFOR	
Unit 1	15%
Unit 2	10%
Unit 3	18%
Total Plant	**14%**

3.0 Gas Turbines:

3.1 Review of Recent Performance

For Stephenville and Hardwoods and Happy Valley, Hydro's UFOP average for 2011 to 2016 is 22.3%. Hydro's actuals for 2015 and 2016 projected are presented in Table 5. As evident from comparison of the 2015 and 2016 performance of both Stephenville and Hardwoods, both plants have had improved reliability in recent years when compared to the five year average of 22.3%. Generation planning assumptions for the Stephenville and Hardwoods gas turbines are 10.6%, with a sensitivity conducted for 20.6%. The generation planning assumption for the Holyrood gas turbine UFOP is 5%, given its age and recent assumption.

Table 5 – Gas Turbines UFOP Actuals

UFOP Performance - Actuals		
	2015	2016 (projected)
Hardwoods	5.7%	3.6%
Stephenville	13.7%	15.7%
Holyrood	3.0%	2.0%

3.2 Projected UFOP for Study Period

In this risk assessment update, Hydro has used the sensitivity UFOP for Hardwoods and Stephenville and the generation planning assumption for the Holyrood gas turbine. This considers the improved reliability of Hardwoods and Stephenville, the recent capital investment, updated operating and staffing processes, and the plan to maintain a loaner engine on the island. The UFOPs for Hydro's gas turbines used in Hydro's Energy Supply Risk Assessment are provided in Table 6.

Table 6 – Projected Gas Turbine UFOPs

Projected DAFOR	
Hardwoods	20%
Stephenville	20%
Holyrood	5%

APPENDIX B

P50 Forecast Analysis

1.0 P50 Peak Demand Forecast

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 P50 forecast, including the contribution of each of the three components, is provided in Table 1.

Table 1 – P50 Base Case Winter Demand Forecast

Base Case Winter Demand Forecast	P50			
	2016/17	17/18	18/19	19/20
Customer Coincident Demand (MW)	1652	1662	1660	1659
Transmission Losses (MW)	54	49	49	49
Station Service (MW)	24	24	24	24
Total Island Interconnected System Demand (MW)	**1730**	**1734**	**1732**	**1732**

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

2.0 Comparison of P50 Forecasts

The peak demand forecasts used in Hydro's initial Energy Supply Risk Assessment were based on customer demand forecasts available in March 2016. For ease of comparison, the P50 forecasts used in each assessment are provided in Table 1.

Table 1 - P50 Forecast Comparison

P50 Forecast Comparison	ESRA - May 2016				ESRA - November 2016				Change (MW)			
	2016/17	17/18	18/19	19/20	2016/17	17/18	18/19	19/20	2016/17	17/18	18/19	19/20
Customer Coincident Demand (MW)	1649	1673	1678	1685	1652	1662	1660	1659	3	-11	-18	-26
Transmission Losses (MW)	60	61	50	51	54	49	49	49	-6	-13	-1	-2
Station Service (MW)	24	24	24	24	24	24	24	24	0	0	0	0
Total Island Interconnected System Demand (MW)	**1733**	**1758**	**1752**	**1760**	**1730**	**1734**	**1732**	**1732**	**-3**	**-24**	**-20**	**-28**

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

APPENDIX C

Avalon Peninsula Capacity with System Additions

Scenario	Equipment Status (In Service (I/S) or Not Available			Avalon Capacity (MW)		
	LIL/MIL	TL267	Incremental 15 MW Curtailment	HRD Units 1,2 Unavailable	HRD Units 1,3 or 2,3 Unavailable	Three Holyrood Units Not Available
1	I/S	I/S	I/S	>1000	>1000	>1000
2	I/S	I/S	N/A	>1000	>1000	992
3	I/S	N/A	I/S	>1000	>1000	950
4	I/S	N/A	N/A	>1000	>1000	935
5	N/A	I/S	I/S	897	907	747
6	N/A	I/S	N/A	882	892	732
7	N/A	N/A	I/S	860	870	690
8	N/A	N/A	N/A	845	855	675

APPENDIX D

Hydro's Operations Standard Instruction T-093, Island Generation Supply - Gross Continuous Unit Ratings

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[5]				123.5	-	123.5
Holyrood Diesels[14]				16.0	(6.0)	10.0
St. Anthony Diesel Plant				9.7		9.7
Hawkes Bay Diesel Plant				5.0		5.0
Total NLH Owned Standby				**254.2**		**248.2**
Total NLH Owned				**1,703.0**		**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]				10.8	-	10.8
Total NLH Purchases				**199.6**		**99.8**
Total NLH System Supply				**1,902.6**		**1,792.4**
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				**2,040.3**		**1,910.3**
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[15]				**2,139.4**		**2,009.4**

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