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May 27, 2016

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: Energy Supply Risk Assessment – Final Report

Further to our correspondence of March 21, 2016, enclosed please find the original plus 12 copies of Newfoundland and Labrador Hydro's report entitled "Energy Supply Risk Assessment."

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas O' Reilly – Cox & Palmer

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador RENEE E. HODDER Renee E. Hodder SIGNATURE 27-05-16 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Energy Supply Risk Assessment

May 2016

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a nalcor energy company

1.0 Executive Summary

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. The intention of the risk assessment is to:

1. Analyze the reliability of Hydro's existing thermal generation assets, particularly the Holyrood Thermal Generating Station and the Hardwoods and Stephenville Gas Turbine plants;
2. Determine Hydro's ability to meet its energy requirements for a range of unit reliabilities in consideration of the historical dry sequence.
3. Determine Hydro's ability to meet its demand requirements given the reliability of these assets; and
4. 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 thermal generation assets and determined that until interconnection to the North American grid is achieved, there is a risk of expected unserved energy (EUE) in excess of planning criteria for Holyrood plant DAFORs greater than 14%.

To mitigate this risk, Hydro examined a number of alternatives and the company recommends the advancement of the in-service date for TL267 to be available for Winter 2017/18. Further, to partially mitigate the risk of EUE for Winter 2016/17, Hydro will consult with its industrial customers and Newfoundland Power to determine the potential of securing any incremental curtailment load that remains within their systems.

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2.0 Introduction

In its letter, dated February 8, 2016, the Board of Commissioners of Public Utilities (the Board) requested that Newfoundland and Labrador Hydro (Hydro) provide:

> *"…a full risk assessment 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".*

This report provides the Board of Commissioners of Public Utilities (the Board) with information regarding Hydro's generation supply, in terms of both energy and capacity, until the expected North American Grid interconnection.

The Energy Supply Risk Assessment is intended to:

1. Analyze the reliability of Hydro's existing thermal generation assets, particularly the Holyrood Thermal Generating Station and the Hardwoods and Stephenville Gas Turbine plants;
2. Determine Hydro's ability to meet its energy requirements for a range of unit reliabilities in consideration of the historical dry sequence;
3. Determine Hydro's ability to meet its demand requirements given the reliability of these assets; and
4. Provide alternatives and options to mitigate exposure, if required.

On May 24, 2016, Board Order No. P.U. 17 (2016)[1] provided Hydro with approval to purchase 12 MW of diesel units currently installed at Holyrood. These units increase the Island Interconnected System (IIS) capacity by 10 MW. At the time of approval, the analysis for this risk assessment had been completed, and as such, this risk assessment does not include the 10 MW of capacity that these units provide to the IIS. While this capacity has not been included

[1] http://pub.nl.ca/orders/order2016/pu/PU17-2016.pdf.

in the analysis, it does improve the reliability of the IIS and is a valuable addition to the Hydro fleet.

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 indicated in Section 5(1) of the Hydro Corporation Act, 2007 as follows:

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

Hydro's electricity generation activities involve the operation of nine hydroelectric generating stations, one oil-fired plant, four gas turbines and twenty five diesel plants. Transmission, distribution and customer service activities include the operation and maintenance of over 3,700 kilometers of transmission lines, as well as 3,300 kilometers of distribution lines. The Company serves over 36,000 direct residential and commercial customers, Newfoundland Power, as well as industrial customers that include Corner Brook Pulp and Paper, North Atlantic Refining, Vale, Praxair, and Teck Resources Ltd.

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 with two parallel 230 kV lines, TL202 and TL206, bringing 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 generation and transmission infrastructure both on the island of Newfoundland and in Labrador.

Figure 1 - Hydro's Generation and Transmission Infrastructure

4.0 System Planning Criteria

4.1 Load Forecasting

For its load forecast, Hydro uses a weather normalized forecast, also referred to as an average peak forecast or a P50 forecast, which means the chances of the actual peak being higher than the forecast peak is 50 per cent or lower than the forecast peak is also 50 per cent. When there is extreme wind and cold, the actual peak will exceed the normalized figure. To reflect this load sensitivity, a P90 load forecast was generated. With the P90 load forecast there is 90 per cent probability of the actual peak being lower and conversely only a 10 per cent probability of it being higher than the forecast peak. Hydro uses both the P50 and the P90 peak demand forecast when assessing system adequacy.

4.2 Generation Planning Criteria

Hydro has established criteria for the IIS that determines the timing of generation source additions. These criteria set the minimum level of capacity and energy installed in 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[2].

Energy: The Island Interconnected System should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability[3].

[2] 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.

[3] 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 (HTGS) is based on energy capability adjusted for maintenance and forced outages.

Additionally, as discussed in *Hydro's Response to the Phase I Report by Liberty Consulting (the Hydro Reply)*[4], Hydro has committed to maintaining a megawatt (MW) reserve of greater than 240 MW. The 240 MW reserve provides 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 the System Planning Department of Newfoundland and Labrador Hydro, and reviewed by the Public Utilities Board of Newfoundland and Labrador, 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%;
3. For contingency or emergency situations, voltages between 90% and 110% are considered acceptable.

These criteria are tested for both P50 and P90[5] peak loading conditions in a deterministic manner where violations are not acceptable.

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

[5] 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.

4.4 Combined Generation and Transmission Planning Outlook

As noted in Section 4.2, existing Generation Planning Criteria define a LOLH target of 2.8 hours per year. As indicated in Figure 2 below, analysis indicates that LOLH is well correlated with Expected Unserved Energy (EUE) [6].

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

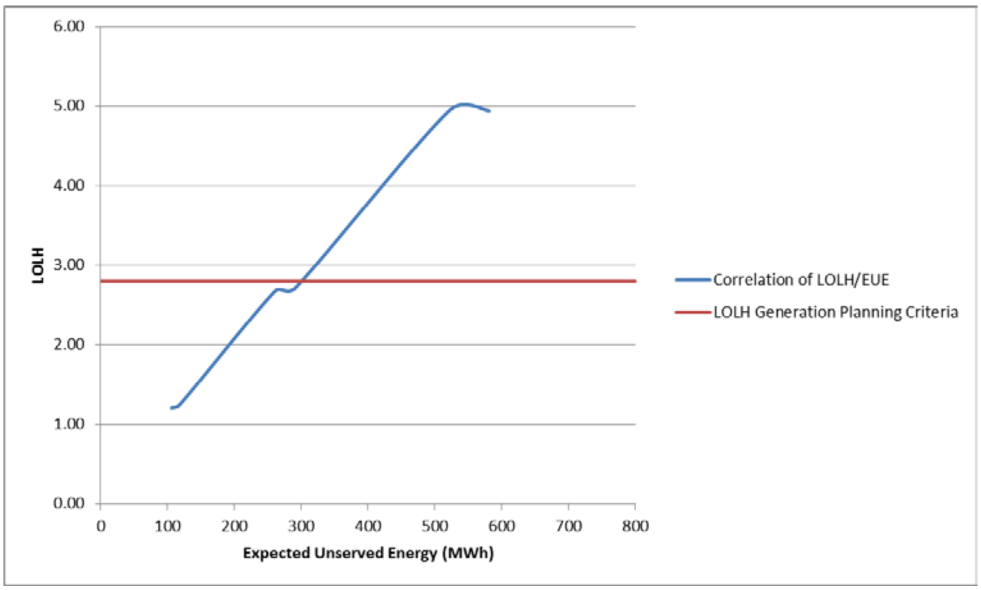

Figure 2 – Illustration of EUE vs LOLH

[6] Expected unserved energy (EUE) 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 Operations and Reliability Focus

A key component of the Energy Supply Risk Assessment is a review of Hydro's current operating practices, reliability culture and the changes made over the past number of years in how Hydro approaches its operations to provide better service to customers.

Over the past several years, Hydro has focused on accelerating asset renewal work and improving system reliability through increased maintenance, capital and additional generation. The company is focused on meeting customers' electricity needs; rebuilding the aging electricity system; using newer and better software and processes for load forecasting; and refining our internal response protocols. Hydro's operating, organizational structure and leadership has also evolved to improve planning and management oversight. At the same time, the company has improved its customer services and communications processes.

This work, coupled with the significant planned investment from 2014 to 2018 in the provincial electricity system, both on the island and in Labrador, has resulted in reliability improvements. Outage frequency (SAIFI) on the IIS improved by approximately 82 per cent for the first quarter (Q1) of 2015 over Q1 2014. For Q1 of 2016, there is an approximate 64 per cent improvement over Q1 2015. Outage duration (SAIDI) on the IIS improved by approximately 90 per cent in Q1 of 2015 over Q1 of 2014. For Q1 of 2016 there is an approximate 41 per cent improvement over Q1 2015.

Hydro has taken a number of steps over the past few years to sharpen its customer focus and ensure improved reliability throughout its operations. Following are some examples of those efforts.

The company installed a new 123.5 MW combustion turbine in Holyrood which provided additional generation capacity on the Avalon Peninsula. This was one of the key actions completed in 2015 to help ensure the winter readiness of our electricity infrastructure and improve reliability for customers. Reliability projects included a wide range of preventative and corrective maintenance, upgrades, inspections, increased testing and capital investment.

In 2016, the company is on track to complete $186 million in capital projects which continue to focus on revitalizing and replacing its aging electricity assets. An immediate priority is strengthening and reinforcing the resiliency of the transmission system to meet the current and future needs of customers.

As well, the company has implemented an integrated equipment outage management tracker and annual winter readiness targets which facilitate a sharper focus on integrated risks and efficient work planning.

The Systems Operations division within Hydro has similarly refined its protocols and implemented rigorous guidelines for managing the electricity system and adverse events. This includes improved severe weather preparedness checklists and the dispatch of standby generation in advance of events and system peaks.

Since 2014, new load forecasting tools and processes have been implemented; system, weather and reserve assessments are completed daily; and the stakeholder notification process and inter-utility operations have also been enhanced through the development of clear protocols and communication channels. All these steps have helped improve both customer service and reliability for customers.

Hydro has a communications on call system in place to update customers and stakeholders about power outages or system events in a timely manner through a variety of channels. The company recently launched a new web mobile and web platform in which Hydro customers can easily access their electricity accounts online and subscribe to text and email notifications about power outages (planned and unplanned) in their regions.

Hydro is also committed to open and transparent sharing of information about the complex workings of electricity system. The company advises customers every time a major piece of generation or transmission equipment is taken offline for planned or emergency work. The details are available on the company's website (www.nlhydro.com) and often shared through other communication channels, such as social and traditional media. Hydro works closely with Newfoundland Power on a daily basis and also informs customers when generation reserve levels are lower than its target levels.

The company, along with Newfoundland Power, developed and implemented three levels of alerts to advise customers on the status of the power supply so customers can better prepare for any potential impacts.

5.1 Generation Reliability

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. While Hydro uses a number of different reliability metrics to represent the availability of its generation and transmission assets, for the existing IIS, EUE and LOLH expectation are primarily influenced by the unavailability of Holyrood thermal units.

Hydro uses a Derated Adjusted Forced Outage Rate[7] (DAFOR) as the metric to quantify the availability of the Holyrood units. To fully evaluate the risk posed to generation supply, a broad range of Holyrood plant DAFORs from 10%-24% were used in this analysis to ensure a robust assessment.

[7] DAFOR is defined as Derating Adjusted Forced Outage Rate which is the per cent of operating plus forced outage time a unit was on a forced outage, adjusted for derating of the unit. It is calculated by dividing the total equivalent forced outage time by the total equivalent forced outage time plus the operating time.

6.0 Load Forecast

Hydro prepares its medium term peak demand forecasts based on demand requirements provided by Newfoundland Power, Hydro's large industrial customers and Hydro's own demand forecasts for its rural service territory[8]. The primary system planning and reporting statistic is the megawatt winter peak demand for the island's system.

As part of this risk assessment, Hydro has:

1. Reviewed its recent peak demand forecasts in relation to actual and weather normalized winter system peak occurrences;
2. Updated its reference case P50 and P90 peak demand forecasts for the latest customer demand information and system transmission losses; and
3. Prepared a sensitivity forecast reflecting potential impact of recent provincial economic outlook on the Newfoundland and Labrador economy.

6.1 Historical Load Forecasts vs Actuals

Table 1 provides recent IIS peak demand forecasts prepared by Hydro and provides the comparative actual and estimated weather normalized peak demands.

On a weather-normalized peak demand basis, actual peak demands for Winter 2014/15 and Winter 2015/16 were lower than Hydro's forecast with a minor variance of three megawatts for Winter 2014/15. The variance in the 2015/16 weather normalized peak and the November 2015 forecast is associated with lower utility[9] peak demand than previously forecast.

[8] Hydro prepares long term demand forecasts for the Island Interconnected System that rely on Hydro's internal model of Newfoundland Power's service territory and is also based on provincial economic projections.
[9] Utility peak demand requirements include the combined requirements of Newfoundland Power and Hydro's rural service territory.

Table 1 - Island Interconnected System Peak (60 Hz)

Forecast and Actual MW		
	2014/15	2015/16
Forecast: November 2014	1713	1756
Forecast: June 2015	N/A	1758
Forecast: December 2015 (Winter Readiness report forecast)	N/A	1737
Acutal Peak	1685	1705
Weather Normalized Peak	1710	1723
Variance (Weather Normalized Peak vs. forecast)	(3)	(14)

Notes:

1. Forecasts reflect P50 weather conditions and include NLH station service.

2. Most recent appropriate forecasts were used to calculate variance. For 2014/15 the November 2014 forecast was used, For 2015/16, the December 2015 forecast was used.

6.2 Near-term Load Forecast and Alternative Load Growth Scenarios

An updated reference case peak demand forecast was developed based on the latest customer demand information available to Hydro as of March 2016. The reference case forecast includes revised load forecast information provided by both Newfoundland Power (as of February 2016) and Vale (as of March 2016). At this time, Hydro has also incorporated updated assessments for the following contributors to system peak demand requirements:

- Transmission losses at system peak loads; and
- P90 weather impacts on utility peak demands.

As a sensitivity to reference case load projections, Hydro assessed the impacts of the most recently released provincial economic outlook using its internal long term forecasting model. Results are indicative of the direction that the NL Provincial economic outlook is expected to have on IIS peak demand requirements in the medium term vis a vis the reference case. The results of this analysis indicate that Hydro should expect a lower IIS peak demand than indicated by previous forecasts. Actual MW demands should be considered preliminary, as they have not been subjected to a fully-iterated load forecast process at the time of the finalization of the report.

The P90 sensitivity load projection includes a 60 MW increase in demand over the P50 sensitivity load projection value. The table below provides a summary of the P50 and P90 peak demand forecasts for the IIS for the winter of 2016/17 through 2019/20.

Table 2 – Island Interconnected System Coincident Demand (MW)

Forecast	P50				P90			
	Winter 2016/17	Winter 2017/18	Winter 2018/19	Winter 2019/20	Winter 2016/17	Winter 2017/18	Winter 2018/19	Winter 2019/20
Jun 30, 2015	1789	1811	1811	1824	1846	1868	1868	1881
Winter Readiness (Dec 1, 2015)	1741	1765	1756	1757	1798	1822	1813	1814
Base Case (Apr 4, 2016)	1733	1758	1752	1760	1801	1831	1819	1827
Post Budget Sensitivity	1720	1740	1730	1730	1780	1800	1790	1790

Notes:

1. Forecast MW includes transmission losses and Holyrood station service requirements.
2. Reductions in peak demand between Winter 2017-18 and Winter 2019-2020 are primarily the result of the decreased transmission losses associated with the completion of TL267.
3. The post budget sensitivity is indiciatve only of the direction the NL budget is expected to have on IIS peak demand. This should not be considered a fully analysed forecast.

7.0 System Constraints and Future Supply Risk

To fully understand the potential risks posed regarding the medium-term future supply for the IIS, detailed transmission, hydrological, and generation system analysis were required.

7.1 Hydrology Analysis

In response to the Board's request of February 8, 2016, Hydro has been providing the Board with regular updates regarding the energy supply circumstances for the IIS through 2019 ("Bi-weekly Energy Supply Report For the Island Interconnected System; filed bi-weekly). As noted in recent updates, inflows to Hydro's reservoirs have increased and, since mid-February, have been higher than those expected during the historical dry sequence.

However, to consider the impact of a repeat of the historical dry sequence (the period in the late 1950s and early 1960s with the lowest inflows in Hydro's hydrologic record), Hydro has modelled the thermal and hydraulic generation that would be required, before energy is available from the expected North American grid interconnections. Under the reference case assumption, thermal generation at the Holyrood plant was limited to 2420 GWh per year to model:

- Maximum plant output of 440 MW (150 MW + 150 MW + 140 MW)
- 5% station service
- 19% DAFOR
- 15% unavailability due to planned/maintenance outages

In a repeat of the historical dry sequence, assumed to start mid-April 2016 (the date of the analysis), the energy capability of the Holyrood plant alone, under the reference case DAFOR assumption of 19%, would not be sufficient to keep Hydro's reservoirs above critical levels[10]. Standby thermal use would be required, but not in excess of the current Hydro installed capacity at the Holyrood, Hardwoods, and Stephenville gas turbines. The installed capacity of

[10] The reservoir storages above which the full peaking capacity of the largest hydroelectric plants can be maintained.

Hydro's standby generation assets that can be used to support a dry sequence is greater than 223 MW. In the driest year, approximately 140 GWh of standby use would be required to keep Hydro's reservoirs above critical levels. Hydro's existing standby generation assets remain capable of supporting the historical dry sequence for the full range of Holyrood plant DAFORs considered. The 12 MW of diesel units installed at Holyrood were excluded from this analysis, as at the date of the analysis Hydro had not yet received approval for the purchase of these units.

Figure 3 shows the energy mix and resultant energy in storage for the May 2016 through 2019 time period should the critical dry sequence repeat, coincident with an annual Holyrood plant DAFOR of 19%. Figure 4 shows the results of the same simulation coincident with an assumed Holyrood plant DAFOR of 24%. Table 3 summarizes the energy mix for both the reference case and high DAFOR sensitivity case. In both instances, Hydro remains capable of meeting its energy supply requirements with its existing fleet of thermal and standby generation. Given that a Holyrood plant DAFOR of 19% is more onerous than the 10% and 14% cases also considered as part of this risk assessment, hydrological evaluation of these operating scenarios was not required.

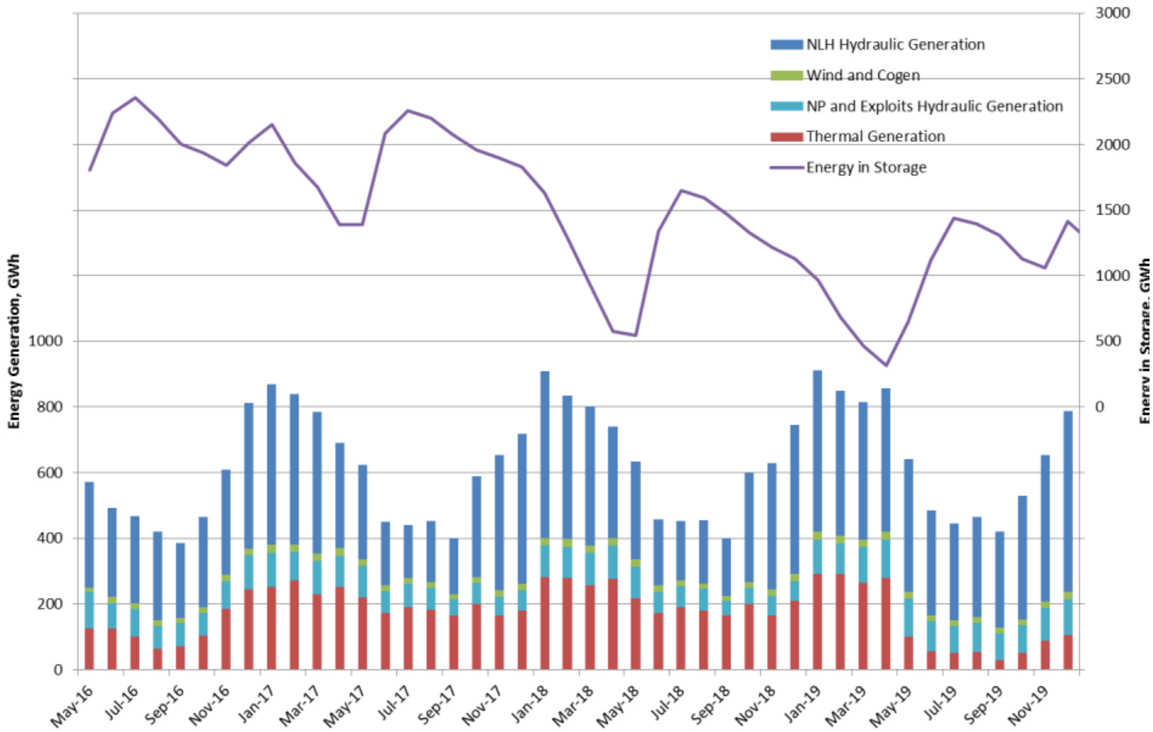

Figure 3 - Energy Generation and Storage: Holyrood plant DAFOR = 19%

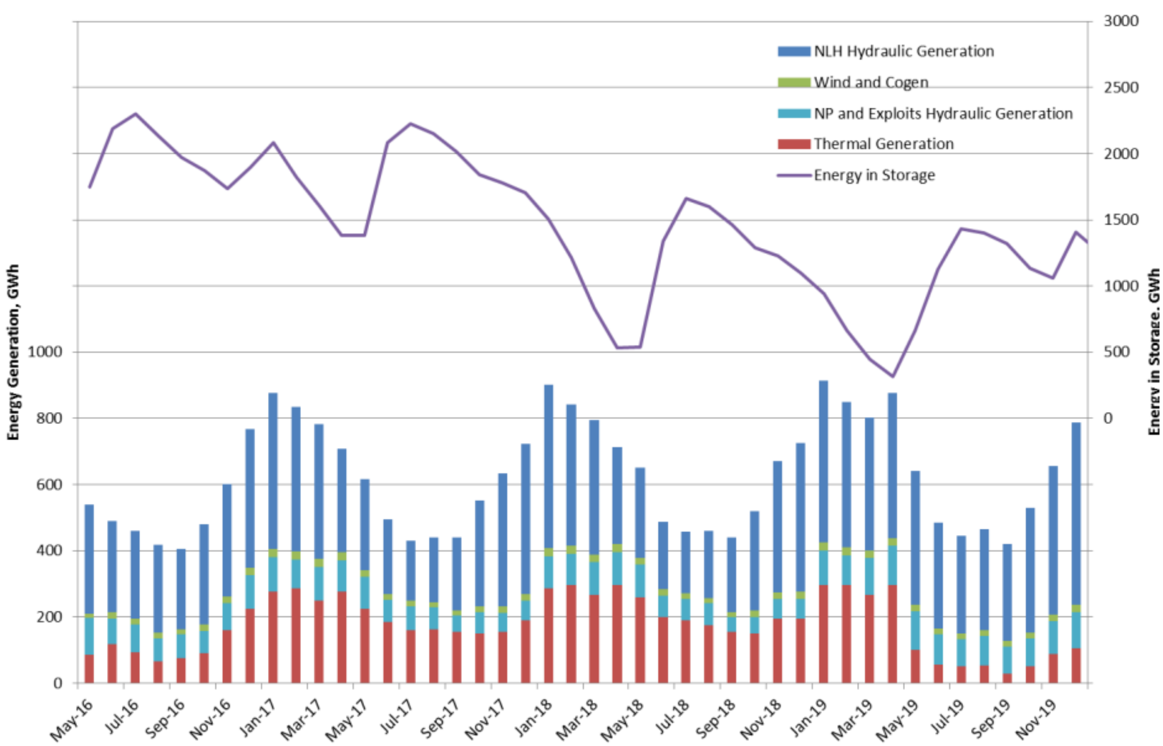

Figure 4 - Energy Generation and Storage: Holyrood plant DAFOR = 24%

Table 3 – Production supply breakout for various Holyrood DAFORs

	System Load (GWh)	Holyrood Plant DAFOR = 19%					Holyrood Plant DAFOR = 24%				
		HTGS Capacity (GWh)	HTGS Generation (GWh)	Standby Thermal (GWh)	Hydro Incl Exploits (GWh)	Purchases (GWh)	HTGS Capacity (GWh)	HTGS Generation (GWh)	Standby Thermal (GWh)	Hydro Incl Exploits (GWh)	Purchases (GWh)
Balance of 2016	4790	1270	1270	0	3350	160	1130	1130	50	3440	160
2017	7540	2460	2460	50	4790	240	2230	2230	250	4820	240
2018	7670	2460	2460	140	4830	240	2230	2230	440	4760	240
2019	7730	2460	1420	100	5960	240	2230	1370	170	5940	240

7.2 Transmission System Analysis

A Transmission Planning analysis was performed to assess the transmission system on the Avalon Peninsula. System capacities under various operating scenarios were quantified and exposures for unserved energy were investigated.

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;
- Thermal generation from the Holyrood Gas Turbine;
- Thermal generation from the Hardwoods Gas Turbine;
- Hydraulic Generation from Newfoundland Power Units;
- Diesel Generation at Vale Terminal Station;
- Wind Generation[11]; and
- 230 kV transmission lines TL203 and TL237 at Western Avalon Terminal Station.

The delivery of hydroelectric capacity from the western portion of the IIS to the Avalon Peninsula is constrained. TL203 and TL237 currently provide the only interconnection for the Avalon Peninsula to the rest of the IIS. Therefore, reserve levels on the Avalon Peninsula differ from those of the IIS and must be calculated separately.

[11] 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 Considerations

A transmission system review was performed to assess the following considerations:

- System Planning Criteria (see Section 4),
- P90 Peak Loading Conditions,
- Loss of two Holyrood Units.

7.2.3 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.

7.2.4 Extended Transmission Planning Analysis

An extended Transmission Planning analysis was performed to assess exposure for unserved energy for various operating scenarios beyond the scope of System Planning criteria. These scenarios included consideration of P90 loading conditions and outages to multiple units on the Avalon Peninsula.

For the purposes of this investigation, it was assumed that the Holyrood thermal units are de-rated in accordance with Table 4. These de-ratings were based on analysis and recommendations from Hydro's Asset Management team.

Table 4 – Assumed De-Rated Capacity for Holyrood Units

Unit	Nameplate Rating (MW)	De-rated Capacity (MW)
Holyrood Unit 1	175	150 (160 Emergency)
Holyrood Unit 2	175	150 (160 Emergency)
Holyrood Unit 3	150	140 (150 Emergency)

i. P90 Peak Loading Conditions

Analysis was performed to assess any potential undesirable system conditions under P90 peak loading conditions. Load flow analysis indicated that under a 2017/18 P90 peak load condition, there is a risk of an overload in the TL202-TL206 transmission corridor in the event of an outage to either TL202 or TL206. This exposure[12] exists for conditions in which the gross Avalon load exceeds approximately 935 MW. This exposure is eliminated once TL267[13] is placed in service. Exposure hours[14] for the TL202-TL206 overload condition are summarized in Table 5.

Table 5 – Exposure for TL202-TL206 Overload Condition (P90)

Winter	Reference Case Avalon P90 Forecast (MW)	Reference Case Exposure Hours (h)	Sensitivity load projection P90 Avalon (MW)	Sensitivity load projection Exposure Hours (h)
2016/17	936	1	931	1
2017/18	960	6	953	5

ii. Loss of Multiple Holyrood Units

Due to transmission system constraints on the Avalon Peninsula, a maximum gross Avalon load of 835 MW can be supported with two Holyrood units out of service. 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 system capacity is limited to approximately 1675 MW, equating to a gross Avalon load of approximately 895 MW after the in service of TL267.

Similarly, a maximum gross Avalon load of 665 MW can be supported with three Holyrood units out of service. Once TL267 is placed in service, total system capacity for three Holyrood units out of service is limited to approximately 1400 MW, equating to a gross Avalon load of approximately 745 MW.

[12] The exposure for unserved energy associated with an outage to TL202 or TL206 is quantified by assuming a 230 kV transmission line unavailability of 0.95% per 100 km over a total transmission line length of 283.7 km for these two lines. This equates to a total unavailability of approximately 2.7%.

[13] TL267 is the third transmission line between Bay d'Espoir and Western Avalon Terminal Station. It is currently scheduled to be in service in Spring of 2018.

[14] Exposure hours are defined as the number of hours that the IIS will be in violation of transmission planning criteria based on probabilistic analysis.

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. Reduced thermal generation availability resulting from lower unit capabilities and increased DAFORs;
2. Revised peak demand forecast; and
3. Sensitivities around both parameters.

This conservative analysis represents a fully stressed case which assumes continued isolated island operation. That is, no interconnection to the North American grid through winter 2019-2020. 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 in-service of either of these assets results in sufficient generation to meet IIS peak demand requirements and satisfy system planning criteria.

7.3.1 Fully Stressed Reference Case Parameters

The reference case reflects Hydro's anticipated capability and P90 demand forecast. The following assumptions were used to develop the fully stressed reference case for this analysis:

1. Key in-service dates:
    a. TL267: mid-2018, available for the 2018/2019 winter peak
    b. The Labrador Island Link (LIL), the Maritime Island Link (MIL), and the Soldiers Pond (SOP) Synchronous Condensers:
        i. Scenario 1 – 2020, available for the 2020/2021 winter peak
        ii. Scenario 2 – 2018, available for the 2018/2019 winter peak
2. For the duration of the study period, the only power can that can be imported over the LIL would be firm recall power from Labrador at a capacity of 110 MW at Soldiers Pond.
3. Up to 300 MW can be imported over the MIL at Bottom Brook.
4. Holyrood diesel generating units are not 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 is 10.8 MW.
8. Curtailable loads are as follows:
    - Kruger – 80 MW
    - Newfoundland Power – 9.9 MW (9 MW on the Avalon Peninsula)
9. Holyrood units are rated in accordance with Table 6.

Table 6 – Holyrood Unit Ratings

	Rating (MW)		
	Unit 1	**Unit 2**	**Unit 3**
Normal Operation	150	150	140
Emergency Operation (i.e. n-1 condition)	160	160	150

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

7.3.2 Sensitivity Load Projection Scenario

Hydro performed additional analysis to determine the potential impact of the sensitivity forecast discussed fully in Section 6.2. All other assumptions remained consistent with the fully stressed reference case.

7.4 Results

All analysis conducted for the Fully Stressed reference case and sensitivity parameters indicate some violation of LOLH criteria for Holyrood plant DAFORs in excess of 14%. Detailed results are contained in the following subsections, while potential mitigation alternatives have been identified and detailed in Section 8.

Reserve margin results are presented in Table 7. A violation of the 240 MW criteria occurs for the fully stressed reference case with P90 forecast in Winter 2017-18. In this instance, the reserve margin is 238 MW, 2 MW less than the 240 MW threshold.

Table 7 – Reserve Margin Analysis

	Winter 2016-17	Winter 2017-18	Winter 2018-19	Winter 2019-20	Winter 2016-17	Winter 2017-18	Winter 2018-19	Winter 2019-20
Island Interconnected System								
	P50				**P90**			
Fully Stressed Reference Case								
Installed Capacity (MW)	2,069	2,069	2,069	2,069	2,069	2,069	2,069	2,069
Forecast (MW)	1,733	1,758	1,752	1,760	1,801	1,831	1,819	1,827
Reserve Margin (MW)	336	311	317	309	268	238	250	242
Fully Stressed Reference Case with Sensitivity Load Projection								
Installed Capacity (MW)	2,069	2,069	2,069	2,069	2,069	2,069	2,069	2,069
Forecast (MW)	1,720	1,740	1,730	1,730	1,780	1,800	1,790	1,790
Reserve Margin (MW)	349	329	339	339	289	269	279	279
Avalon System								
	P50				**P90**			
Fully Stressed Reference Case								
Installed Capacity (MW)	1,155	1,155	1,215	1,215	1,155	1,155	1,215	1,215
Forecast (MW)	909	925	934	940	936	960	970	976
Reserve Margin (MW)	246	230	281	275	219	195	245	239
Fully Stressed Reference Case with Sensitivity Load Projection								
Installed Capacity (MW)	1,155	1,155	1,215	1,215	1,155	1,155	1,215	1,215
Forecast (MW)	903	916	922	927	931	953	958	963
Reserve Margin (MW)	252	239	293	288	224	202	257	252

Note: Installed capacity does not include 20 MW of voltage reduction or the Holyrood diesels (10MW)

7.4.1 Fully Stressed Reference Case Results – P50 and P90 Forecasts

For both P50 and P90 load forecasts, violations of planning criteria occur for Holyrood plant DAFORs in excess of 14%. EUE results are provided in Table 8 and Table 9.

Table 8 – EUE Fully Stressed Reference Case Results – P50 Forecast

P50 Analysis				
Year	2016/17	2017/18	2018/19	2019/20
HRD DAFOR	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
10%	-	-	-	-
14%	57	179	-	-
19%	532	786	-	9
24%	1305	1758	240	307
HRD DAFOR	Incremental Annual Expected Outage Hours			
10%	-	-	-	-
14%	9,500	29,800	-	-
19%	88,700	130,900	-	1,500
24%	217,600	293,000	40,000	51,100

Table 9 – EUE Fully Stressed Reference Case Results – P90 Forecast

P90 Analysis				
Year	2016/17	2017/18	2018/19	2019/20
HRD DAFOR	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
10%	-	-	-	-
14%	83	204	-	-
19%	577	831	19	54
24%	1375	1828	309	377
HRD DAFOR	Incremental Annual Expected Outage Hours			
10%	-	-	-	-
14%	13,800	34,000	-	-
19%	96,200	138,500	3,100	9,100
24%	229,200	304,600	51,600	62,700

As evident through a comparison of Table 8 and Table 9, the P90 forecast results in incremental EUE, and subsequently annual expected outage hours, over the P50 forecast. Given that the P90 forecast provides the higher energy requirement of the two scenarios, the P90 forecast forms the reference forecast for the remainder of the analysis.

7.4.2 Fully Stressed Reference Case Results – P90 Sensitivity Load Projection

The sensitivity load projection results in a decrease in EUE, and in turn incrementally less annual expected outage hours. While a reduction has occurred, EUE criteria continues to be violated in the same years for both this sensitivity case and the fully stressed reference case, as detailed in Table 10.

Table 10 - P90 Sensitivity Forecast

P90 Analysis				
Year	**2016/17**	**2017/18**	**2018/19**	**2019/20**
HRD DAFOR	**Expected Unserved Energy in Excess of Planning Criteria (MWh)**			
10%	-	-	-	-
14%	64	162	-	-
19%	545	757	6	36
24%	1327	1717	290	349
HRD DAFOR	**Incremental Annual Expected Outage Hours**			
10%	-	-	-	-
14%	10,700	27,000	-	-
19%	90,800	126,200	1,000	6,000
24%	221,200	286,200	48,400	58,100

8.0 Mitigation Alternatives

As discussed in Section 7.4, all analysis conducted for reference and sensitivity case parameters indicate a violation of LOLH criteria for a plant DAFOR of 14% when analyzed under a P90 load forecast.

To mitigate the LOLH violation for these scenarios and reduce the identified transmission exposure, four feasible alternatives exist:

1. Advancement of TL267 in-service;
2. Addition of standby generation on Avalon Peninsula;
3. Retention of the Holyrood Diesels concurrent with the securing of an additional curtailable Avalon Peninsula load; and
4. Additional investment in Holyrood plant assets.

Transmission planning analysis was performed to determine the impact of each alternative on Avalon Peninsula capacity. Resultant capacities are provided in Appendix B. EUE was used to quantify the benefit to the IIS provided by each alternative.

8.1 Advancement of TL267

The advancement of TL267 results in the asset being placed in-service for Winter 2017-18. As detailed in Table 11, this results in lower EUE, and thus lower annual outage hours, for the Winter of 2017/18. For a P90 load forecast with Holyrood plant DAFORs up to 19%, the advancement of TL267 results in EUE within existing planning criteria for Winter 2017-18. All other years have the same results as those of the fully stressed case, as described in Table 9, given that the fully stressed case reflects the in-service of TL267 in Winter 2018/19.

Table 11 - Advancement of TL267

P90 Analysis				
Year	2016/17	2017/18	2018/19	2019/20
HRD DAFOR	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
10%	-	-	-	-
14%	83	-	-	-
19%	577	-	19	54
24%	1375	**221**	309	377
HRD DAFOR	Incremental Annual Expected Outage Hours			
10%	-	-	-	-
14%	13,800	-	-	-
19%	96,200	-	3,100	9,100
24%	229,200	**36,800**	51,600	62,700

8.2 Addition of Standby Generation on Avalon Peninsula

The installation of additional standby generation is another alternative to address violation of planning criteria. Due to the transmission system constraints discussed in Section 7.2, any additional generation should be installed on the Avalon Peninsula, due to the reduction in associated losses. Due to the construction schedule for an additional gas turbine (GT), also referred to as a combustion turbine, this option will provide no mitigation for the Winter 2016-17 season.

As detailed in Table 12, the addition of a 60 MW GT results in lower EUE, and thus lower annual outage hours, for all winters excluding winter 2016/17. For Holyrood plant DAFORs in excess of 19%, the addition of a GT continues to result in a violation of planning criteria. Note that the in-service of TL267 in winter 2018/19 is the reason why there is no continued violation of criteria beyond Winter 2017/18.

Table 12 - Addition of 60 MW GT

P90 Analysis				
Year	2016/17	2017/18	2018/19	2019/20
HRD DAFOR	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
10%	-	-	-	-
14%	83	-	-	-
19%	577	11	-	-
24%	1375	304	-	-
HRD DAFOR	Incremental Annual Expected Outage Hours			
10%	-	-	-	-
14%	13,800	-	-	-
19%	96,200	1,800	-	-
24%	229,200	50,600	-	-

8.3 Retention of the Holyrood Diesels concurrent with the securing of Additional Curtailable Avalon Peninsula Load

On May 24, 2016, Board Order P.U. 17 (2016) granted Hydro approval to purchase 12 MW of diesel units installed at Holyrood. These units provide 10 MW to the IIS and result in a reduction in EUE.

Further reduction of EUE is possible for Winter 2016/17 if additional curtailable Avalon Peninsula load is secured, or if lower IIS peak demand materializes. Due to schedule requirements associated with the other alternatives, this remains the only identified alternative that provides a reduction in EUE for Winter 2016/17.

As detailed in Table 13, while violation of criteria continues for multiple plant DAFORs, there is a significant reduction in the EUE. For example, the EUE in Winter 2016/17 in the fully stressed reference case is 577 MWh, compared to the 250 MWh EUE should this alternative be implemented. This represents a 57% reduction in EUE for those parameters.

The *Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015*[15], completed for Hydro and Newfoundland Power in 2015, indicated that "demand

[15] http://www.pub.nl.ca/applications/IslandInterconnectedSystem/files%5Creports%5CNLConservationandDemandManagementCDMPotentialStudy-CommercialSectorFinalReport-August2015-09-16.pdf.

reduction potential is dominated by the reductions associated with demand response curtailment measure, with much of this potential already in place through existing utility curtailment programs." Hydro will actively consult with its industrial customers and Newfoundland Power to determine the potential of securing any incremental curtailment load that remains within their systems.

Finally, incremental curtailable load would provide additional reliability for customers in Winter 2016/17 and could be combined with either of the other alternatives which, due to scheduling requirements, cannot be available for this winter.

Table 13 - Retain Holyrood Diesels and Add 15 MW Curtailable

P90 Analysis				
Year	2016/17	2017/18	2018/19	2019/20
HRD DAFOR	Expected Unserved Energy in Excess of Planning Criteria (MWh)			
10%	-	-	-	-
14%	-	7	-	-
19%	250	410	-	-
24%	766	1063	64	110
HRD DAFOR	Incremental Annual Expected Outage Hours			
10%	-	-	-	-
14%	-	1,100	-	-
19%	41,600	68,300	-	-
24%	127,600	177,200	10,600	18,300

8.4 Additional investment in Holyrood plant assets

Holyrood is an aged plant, with over 40 major systems for each generating unit. For each system, Hydro has maintenance and capital programs to maintain and refurbish/replace systems and components. Hydro's maintenance and capital programs are conducted to optimize expenditures to be economically reasonable. However, as the plant is aged and near end-of-life, systems and components may fail before problems can be identified and corrected. Some of these failures may result in events which would negatively impact the Holyrood plant DAFOR. While additional investment in Holyrood plant assets may result in increased reliability due to the above noted uncertainty, Hydro remains challenged to forecast the overall impact on DAFOR. Hydro continues to evaluate and include appropriate investment in Holyrood plant assets to ensure continued delivery of safe, reliable power to its customers through interconnection.

8.5 Recommendation

Following the analysis, Hydro recommends the advancement of TL267, as detailed in Section 8.1. Additionally, Hydro recommends the securing of additional curtailable load on the Avalon Peninsula. The combination of these two alternatives, with the additional positive impact of the Holyrood diesels, provides reasonable mitigation of the risk for unserved energy through interconnection. Results for this alternative are detailed in Table 14.

Table 14 – Recommended Alternative: Advancement of TL267, retention of Holyrood diesels and addition of 15 MW curtailable Avalon Peninsula load

P90 Analysis				
Year	**2016/17**	**2017/18**	**2018/19**	**2019/20**
HRD DAFOR	**Expected Unserved Energy in Excess of Planning Criteria (MWh)**			
10%	-	-	-	-
14%	-	-	-	-
19%	250	-	-	-
24%	766	221	64	110
HRD DAFOR	**Incremental Annual Expected Outage Hours**			
10%	-	-	-	-
14%	-	-	-	-
19%	41,600	-	3,100	9,100
24%	127,600	36,800	51,600	62,700

Finally, for this alternative, the in-service of the Labrador Island Link or the Maritime Link ensures no further violation of planning criteria for the study period. These results are detailed in Table 15.

Table 15 – Recommended Alternative with in-service of Labrador Island Link and Maritime Link

P90 Analysis				
Year	**2016/17**	**2017/18**	**2018/19**	**2019/20**
HRD DAFOR	**Expected Unserved Energy in Excess of Planning Criteria (MWh)**			
10%	-	-	-	-
14%	-	-	-	-
19%	250	-	-	-
24%	766	221	-	-
HRD DAFOR	**Incremental Annual Expected Outage Hours**			
10%	-	-	-	-
14%	-	-	-	-
19%	41,600	-	-	-
24%	127,600	36,800	-	-

9.0 Conclusion

Hydro has conducted a comprehensive risk assessment of its ability to meet Island Interconnected System energy and demand requirements until the expected interconnection with the North American grid. The intention of the risk assessment is to:

1. Analyze the reliability of Hydro's existing thermal generation assets, particularly Holyrood Thermal Generating Station and Hardwoods and Stephenville Gas Turbine plants;
2. Determine Hydro's ability to meet its energy requirements for a range of unit reliabilities in consideration of the historical dry sequence.
3. Determine Hydro's ability to meet its demand requirements given the reliability of these assets; and
4. 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 thermal generation assets and determined that until interconnection to the North American grid is achieved, there is a risk of EUE in excess of planning criteria for Holyrood plant DAFORs greater than 14%.

To mitigate this risk, Hydro recommends the advancement of the in-service date for TL267 to be available for Winter 2017/18. Preliminary analysis indicates that the advancement of TL267 will likely result in a shifting of cash flows between years and is not, at this point, expected to have a material increase in cost. Hydro will continue to comply with the Board-approved capital budget guidelines and update the Board regarding any changes as appropriate.

To partially mitigate the risk of EUE for Winter 2016/17, Hydro continues to consult with its industrial customers and Newfoundland Power to determine the potential of securing any incremental curtailment load that remains within their systems.

The recommended alternative provides the optimal balance in reduction of supply risk and overall cost, making it the best option for customers.

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**

Revision: **5**
Date: **November 10, 2015**

Scenario	Equipment Status (X denotes in-service)					Avalon Capacity (MW)	
	LIL/MIL	TL267	60 MW GT	15 MW Curtailment	HRD Diesels (10 MW)	Two Holyrood Units Not Available	Three Holyrood Units Not Available
1	X	X	X	X	X	>1000	>1000
2	X	X	X	X	-	>1000	>1000
3	X	X	X	-	X	>1000	>1000
4	X	X	X	-	-	>1000	>1000
5	X	X	-	X	X	>1000	>1000
6	X	X	-	X	-	>1000	>1000
7	X	X	-	-	X	>1000	>1000
8	X	X	-	-	-	>1000	>1000
9	X	-	X	X	X	>1000	>1000
10	X	-	X	X	-	>1000	>1000
11	X	-	X	-	X	>1000	>1000
12	X	-	X	-	-	>1000	995
13	X	-	-	X	X	>1000	950
14	X	-	-	X	-	>1000	940
15	X	-	-	-	X	>1000	935
16	X	-	-	-	-	>1000	925
17	-	X	X	X	X	990	840
18	-	X	X	X	-	980	830
19	-	X	X	-	X	975	825
20	-	X	X	-	-	965	815
21	-	X	-	X	X	920	770
22	-	X	-	X	-	910	760
23	-	X	-	-	X	905	755
24	-	X	-	-	-	895	745
25	-	-	X	X	X	930	760
26	-	-	X	X	-	920	750
27	-	-	X	-	X	915	745
28	-	-	X	-	-	905	735
29	-	-	-	X	X	860	690
30	-	-	-	X	-	850	680
31	-	-	-	-	X	845	675
32	-	-	-	-	-	835	665