Review of
Newfoundland and Labrador Hydro's
Reliability and Resource Adequacy Study

Executive Summary

Presented to:
The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

1451 Quentin Rd Suite 400 #343
Lebanon, PA 17042

August 19, 2019

Executive Summary

Background and Purpose of this Report

- The Board of Commissioners of Public Utilities (the "Board") retained the Liberty Consulting Group ("Liberty") to review Newfoundland and Labrador Hydro's ("Hydro") Reliability and Resource Adequacy Study ("RRA Study"), dated November 16, 2018.
- This report is the latest in a series of reports by Liberty on power supply adequacy and reliability on the Island of Newfoundland. Liberty was first retained by the Board in 2014 following significant outages on the interconnected electrical system on the Island of Newfoundland ("IIS"). Liberty has addressed, in reports in 2014 and 2016, the reliability and adequacy of the IIS over the short, medium and longer terms, including consideration of the reliability implications of the interconnection of the Lower Churchill Project ("LCP") to the IIS. In addition, Liberty has been monitoring on a quarterly basis Hydro's progress in getting ready to transition from LCP construction to operation.
- Hydro's RRA Study was a principal focus of our review, but we examined other important sources of information as well. They include Hydro's recent, regular near-term reliability reports to the Board, studies and documents arising from our continuing examination of readiness for LCP operation (focusing in major part on the Labrador Island Link ("LIL"), analyses of LIL outage risk and duration, and reports by experts retained by Hydro. We also reviewed Hydro's responses to a number of information requests, conducted a number of interviews and work sessions with executives and managers, and examined facilities on-site and through extensive photographic mapping.
- This report presents our conclusions on the adequacy of Hydro's RRA Study. It makes a number of recommendations for additional analysis and about how to use the planning foundation that Hydro has created to support a process that incorporates full stakeholder engagement in determining the adequacy of supply and reliability of the IIS.

Baseline Assessment of Hydro's November 2018 RRA Study

- We found that Hydro's RRA Study reflects the conduct of an appropriately comprehensive examination of future reliability on the IIS and the Labrador interconnected system. Reflecting the linkage provided by the LIL, Hydro has for the first time planned the two regions jointly, terming them the Newfoundland Labrador Interconnected System ("NLIS"). Hydro performed its analyses using sound methods and tools. It applied criteria and assumptions generally appropriate in developing a robust range of supply alternatives.
- Generation availability forms one important set of assumptions. Given our past concerns about generation plant performance and Hydro's assumptions about them, we reviewed unit conditions, performance data, and management changes that have influenced them. We continue to have recommendations for practice improvement, but found sufficient reason to accept Hydro's availability assumptions for planning purposes.
- The RRA Study provides a sound baseline for stakeholder and Board consideration of scenarios and alternatives for addressing the conditions expected to occur under them. However, some critical factors call for immediate, more robust consideration of risks with

reliability consequence, the means for mitigating them, the costs of such mitigation, and the relationship between that cost and the value to be placed on the level of risk mitigation they can provide.

- We did find a number of aspects of Hydro's planning methods and assumptions that should undergo validation and, in some cases, alteration. These narrow or technical issues can be addressed at the same time as the analysis of critical factors that we recommend.

Forecasting Electrical Needs Under Uncertainty

- Future electrical needs always entail significant uncertainty. Therefore, utilities, as Hydro has done, analyze needs under a range of forecasts. Particular issues here give that uncertainty a larger role than typical in performing assessments of system needs. Nearer-term potential transmission system reinforcement needs and additional capacity requirements that Hydro has identified occur under scenarios that make assumptions about growth particularly important.
- The effect of the looming increase in rates must also be considered. The means for mitigating this increase, and the means for changing future demand and usage through a potential combination of usage enhancing and demand and usage reduction possibilities are all now under active study in the Reference on Rate Mitigation Options and Impacts. The outcome of these efforts may have considerable impact on the timing of future needs.
- Completing analysis of the subjects our report identifies should take place by the time that stakeholders and the Board in the Reference will address factors such as elasticity, rate mitigation, and future usage and demand.

Long Term Reliability

- Utilities model system operations by identifying and modeling contingencies that may degrade system capabilities from what results under normal conditions. Modeling a single contingency produces what is called an N-1 approach to contingency modeling. Hydro has historically used and currently uses this approach, which we found appropriate for baseline planning purposes.
- However, two factors question whether stopping with that baseline is appropriate in examining the future. The first is the nature of Hydro's system which, compared with others using the criteria like those Hydro has applied, places high reliance on its largest supply resources and has comparatively less strong connections to other systems. The second lies in deciding what adverse circumstances may be "tolerated" for planning purposes because they are defined as second contingencies (N-2) occurring simultaneously with the first contingency. We concluded that Hydro needs to undertake greater analytical, quantitative analysis of such contingencies.
- Hydro considers simultaneous loss of both poles of the LIL an N-2 case, even though the line runs overhead for much of its approximately 1,100 km length. The same structures carry both poles. A failure of one structure (a single physical event) can cause loss of both poles.

- The LIL's criticality and its vulnerability to a single physical event led us to conclude that an extended bipole outage requires detailed examination. In particular, we consider it necessary to examine the likelihood of bipole loss due to line structure failure. Such failure will have the greatest consequence for service continuity at peak periods. The examination we consider necessary must consider those consequences under conditions not only producing high electric loads, but also difficult line access and repair conditions.
- Hydro has undertaken comprehensive analysis of LIL outages, but it is not clear that the assessment of outage probabilities underlying the analysis relies on return-periods using local, as opposed to CSA-standard weather conditions. The use of local conditions produces higher probabilities more appropriate for probability assessment.
- The analyses Hydro has provided also do not quantify a range of repair durations incorporating a variety of outage locations and failures. We have read or heard during our work of two- to three-week durations, with a single-span bypass construction effort forming one of the bases for such estimates. However, that test occurred at a favorable location under benign weather circumstances.
- Estimation of outage durations should consider adverse weather, multiple, single-structure failure locations, cascading failures, and remote-location failures. These circumstances can long extend times to restore operation, through temporary bypass of the affected spans. Such considerations produce a range of durations extending to multiple months, not merely two to three weeks. Work by Hydro using its shorter durations postulates significant service disruption. The analysis needs to expand to provide a measure of customer consequence for significantly longer outage durations during peak conditions. This information is required to support properly informed stakeholder discussions and resolution of whether Hydro needs to consider measures to mitigate the consequences of extended LIL outages at peak times.
- In the past several months, study by Hydro has identified other consequences from a loss of both LIL poles. That work assessed impacts on the Island transmission system under those circumstances, finding a number of planning criteria violations when contingencies on the transmission system occur. Hydro has recommended the adoption of "emergency" criteria that would change violations under its current criteria to non-violations under its emergency ones. More generation on the Avalon Peninsula potentially solves these LIL unavailability concerns.
- Hydro proposes to retire the three steam generating units at Holyrood after the LCP begins operation. One unit at Holyrood would continue operation indefinitely as a synchronous condenser (a device designed to provide voltage or power factor support). It does appear that Hydro is considering the continuation of generation at the three Holyrood units pending an LCP "phase-in" period of perhaps several years.
- We strongly support continuation of electricity production at the Holyrood steam units during LCP phase-in, and urge finalization of Hydro's commitment to do so, failing immediate identification of a preferable alternative. We believe that Hydro needs immediately to assess the ability of Holyrood to serve as a source for mitigating the risks of bipole LIL outages, whose potential durations may prove material, subject to the study we recommend above. That study needs to consider the costs of giving Holyrood units the

capability to respond as effectively as they can, the costs of continuing operation, and the degree of mitigation they can produce after modification. In our opinion it is important to complete as soon as possible this study of short- and long-term Holyrood life extension costs, and of its operating costs, reliability, and responsiveness in addressing contingencies such as extended bipole outages.

Long-Term Reliability - - Relating Risk Mitigation to the Costs of Providing It

- In the months immediately to come, stakeholders and the Board will receive data and analysis bearing on the timing of the resource needs that have emerged from Hydro's RRA Study. For now, we agree that commitment to sizeable expenditures to meet expected future needs should await that information and analysis. However, important work must be completed in the meantime to ensure that the required decisions will flow from a sufficiently robust view of risks, mitigation means, costs, and benefits.
- Work that should be undertaken includes completing our recommended analysis of LIL structural failures considering:
  - Failure rates based on both local weather conditions and the differences in design of line segments
  - A robust range (not a simple, mid-point estimate) of outage durations under extreme weather conditions at time of peak loads
  - Consideration of access times with heavy snow cover and wind conditions requiring ground access
  - Remote failure locations, multiple failure sites, and cascading structure failures.

- The work also needs to provide a quantitative assessment of service disruption consequences at peak load times and for extended periods and the capital and operating costs of alternative mitigation measures (including the continuation of Holyrood as a generating plant in the short and longer term).
- We also recommend consideration of an additional measure - - one that will learn from stakeholders how they value risk reduction in terms of what it will cost them. Hydro should engage stakeholders in the immediate term in a process that seeks to quantify this trade-off. The information whose immediate-term development we recommend will provide a basis for doing so.
- The specific goal of this measure is to make available clear and quantitative information about risk occurrence probability and consequence, on the one hand, and clear and quantitative information about the costs and results of mitigation measures, on the other hand. Some efforts have sought to generate from such exercises an explicit measure of what is termed the "Value of Lost Load." Whether the exercise we propose would do that directly, or implicitly by gauging reaction to before and after risks and costs, it can have value in making decisions about commitments to reliability measures that have a high degree of transparency to those who will pay for those commitments.

Near-Term Reliability

- At the most recent monitoring meeting on LCP progress in July, 2019, Nalcor reported that low-load LIL testing has been delayed by nearly two months to January 2020. The current schedule for reaching this milestone has no "float" in it. Even if this is reached, there is no assurance that reliable bipole operation will commence given the continuing significant issues with the GE software required to operate the LIL
- As we pointed out in previous reports, supply over the LIL is now critical in meeting Hydro's reliability planning criteria in certain scenarios for winter seasons. We recommend that Hydro immediately conduct a detailed assessment of the impacts of the delay in LIL operation into and past this coming winter which should include an updated analysis assuming "no LIL" as its expected case, analyzing contingencies as in its May 2019 near term reliability report and clarifying assumptions about the import of energy over the Maritime Link.

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Presented to:
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THE LIBERTY CONSULTING GROUP

1451 Quentin Rd Suite 400 #343
Lebanon, PA 17042

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I. Background

A. History

Newfoundland and Labrador Hydro ("Hydro"), a subsidiary of Nalcor Energy ("Nalcor") provides wholesale and retail service throughout Newfoundland and Labrador. In December 2012, the provincial government sanctioned the construction of the Lower Churchill Project ("LCP"), which includes an 824 MW hydro plant at Muskrat Falls in Labrador and a 1,100 km, high-voltage, direct-current ("dc") Labrador Island Link ("LIL") connecting Muskrat Falls to the Avalon Peninsula. Originally scheduled to enter service in late 2017, with full power in 2018, generation at Muskrat Falls is now scheduled to commence in late 2019, with a phasing in of the operation of all its generators by the fall of 2020.

A 30 km undersea section of the LIL crosses under the Strait of Belle Isle. The LCP also includes the Labrador Transmission Assets ("LTA"), which consist of two 315kV ac transmission lines between Muskrat Falls and Churchill Falls. The LTA offer a path for power flows into and from Newfoundland and Labrador through Quebec. The Maritime Link ("ML"), a high voltage dc line of approximately 360 km, including a 180 km subsea cable under the Cabot Strait, connects the Island of Newfoundland to Nova Scotia. Built by Emera primarily to enable the sale of energy from Muskrat Falls to and beyond Nova Scotia, the ML also has the capability to bring energy into Newfoundland - - potentially of substantial benefit following major Island system disturbances.

Nalcor plans to operate the LCP assets through its Power Supply organization, with Hydro purchasing a significant portion of the output of Muskrat Falls and rights to transport it across the LIL to Hydro's Island Interconnected System ("IIS"). Emera, the parent company of Nova Scotia Power Company (that province's retail electricity supplier), has an entitlement to a portion of the output of the Muskrat Falls generating station, and minority ownership of the LIL.

Following significant outages on Hydro's IIS in 2013 and 2014, the Board of Commissioners of Public Utilities (the "Board") initiated an inquiry and investigation into the circumstances surrounding these outages. The Board determined that the investigation would address IIS supply adequacy and reliability over the short, medium and long terms, considering the interconnection of Muskrat Falls to the IIS across the LIL. The Board retained us, The Liberty Consulting Group ("Liberty"), to assist with the investigation. We filed on April 24, 2014 an interim report ("Interim Report") as requested by the Board. It addressed the causes of the IIS events in 2013 and 2014, and addressed short-term reliability issues (through 2016), recommending system changes to reduce the risk of further outages.

In October 2014 the Board decided to address the scope of its investigation in two phases:

- Adequacy and reliability of the IIS up to Muskrat Falls interconnection
- Subsequent implications of interconnection for IIS adequacy and reliability.

We issued two December 17, 2014 reports ("December 2014 Report(s)") - - one focused on Hydro and the other on Newfoundland Power. These reports addressed the causes of the earlier power outages and system disruptions, the responses of the utilities to the recommendations made in

Liberty's Interim Report, and issues we viewed as affecting reliability before and up to Muskrat Falls interconnection with the IIS. We concluded then that, despite the addition of new generation, an improved winter readiness program, and new capacity assistance agreements with certain industrial customers, power supply on the IIS remained tight, with very low generation reserves. The risk of outages remained high.

We next issued an August 19, 2016 final report, *Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls* ("August 2016 Report"). This report reflected heightened reliability concerns on our part, arising in large part from performance at Hydro's thermal generating units after our December 2014 reports. We concluded that the risk of supply-related outages pending Muskrat Falls interconnection remained high.

The August 2016 Report also presented the results of our assessment of the integration of the LIL and the ML into the IIS. As directed by the Board, we did not address detailed technical information or project engineering and construction issues involving Muskrat Falls or the LIL, except as necessary to understand the reliability risks associated with interconnection to the IIS and delays in adding to power supplies available to Hydro.

As our August 2016 Report observed from an electrical perspective, the introduction of a large amount of power landing at one point in the relatively small IIS, raised questions of stability and reliability. That report addressed those concerns. We considered interconnection to the North American grid through the ML an opportunity to mitigate these concerns and to provide reliability enhancements for the IIS, opportunities to make economically attractive purchases and sales of electricity, and to share reserves among other utilities. Successful operation of both Muskrat Falls and the ML comprised then, as they do now, essential elements in ensuring IIS supply adequacy and reliability.

B. Purpose of this Report

This report thus comprises the latest in a series addressing our views of reliability in the province. The Board requested that Liberty review Hydro's Reliability and Resource Adequacy Study ("RRA Study") dated November 16, 2018. We reviewed Hydro's study and the analyses undertaken in connection with or related to the study and its scope, requested and reviewed supplemental information, conducted a number of interviews and working sessions with Hydro and Nalcor management, analyzed the methods and conclusions they reached with respect to long-term reliability and resource adequacy, and met with Board Staff. We also conducted on-site reviews at Soldiers Pond (a central point of interconnection between the dc and ac networks) and at a number of LIL line locations where it traverses eastern and western portions of the Island. We also conducted an examination of aerial images, focusing on particularly remote and more rugged terrain crossed by the LIL.

Our review addressed the three volumes of Hydro's RRA Study:

- Volume I: Study Methodology and Proposed Planning Criteria
- Volume II: Near-Term Reliability Report
- Volume III: Long-Term Resource Plan.

We also reviewed other, recent planning studies, among them, two from TransGrid Solutions Inc. ("TGS"):

- Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation dated November 21, 2018
- Avalon Capacity Study: Solutions to Serve Island Demand during a LIL Bipole outage dated May 24, 2019.

C. Structure and Configuration of the Province's Electrical System

Two electric utilities, both regulated by the Board (Hydro, a crown-owned utility, and Newfoundland Power, an investor-owned utility) serve the electrical requirements of the two major regions of the province - - the island of Newfoundland and Labrador. Hydro provides the vast majority of generation and bulk transmission and Newfoundland Power provides retail electricity service to most Newfoundland customers. Hydro also provides retail service in Labrador and to a number of customers on the Island.

Hydro's bulk transmission network includes the IIS, whose major components consist of large hydroelectric generation capability off the Avalon Peninsula and a 230kV transmission network that extends from Stephenville in the west to St. John's in the east, supported by a series of other interconnected high voltage lines, some in network configuration and others operating radially. The radial transmission lines extend to load centers served at retail by Newfoundland Power and, to a much lesser extent, Hydro.

Hydro plans to purchase a significant portion of the capacity and energy it requires to serve retail customers (its and those of Newfoundland Power) from Muskrat Falls, with delivery across the LIL. The IIS first became interconnected to the North American grid through 2018 connections to: (a) the LIL and the LTA, extending through Labrador, and (b) the ML extending to the Nova Scotia bulk transmission system. The LIL had been operating in monopole mode and at reduced capacity since its first energization in June of 2018. Removed from service in early May of 2019, it had been scheduled to return to service in bipole operation in November 2019. We learned at the end of July, however, that the schedule has been extended, with low-power testing now not slated to commence until late January 2020.

A combination of hydroelectric supply and oil-fired steam generation supplies service to IIS-connected retail customers, with supply to interconnected Labrador customers provided by hydroelectricity from the Churchill Falls station. Small diesel units generate the electricity serving non-interconnected Island and Labrador customers. The major system expansion that the LCP will bring will add significantly to hydroelectric generation resources serving the Island, through the HVdc connection provided by the LIL. Expansion also includes the ML, an HVdc connection already in operation between Newfoundland and Nova Scotia. Full operation of both HVdc connections and the Muskrat Falls project are expected in 2020. The presence of the LIL has, for the first time, caused Hydro to expand its integrated planning process from just the IIS to what it terms the Newfoundland and Labrador Interconnected System ("NLIS"), which adds interconnected portions of its Labrador system to the IIS.

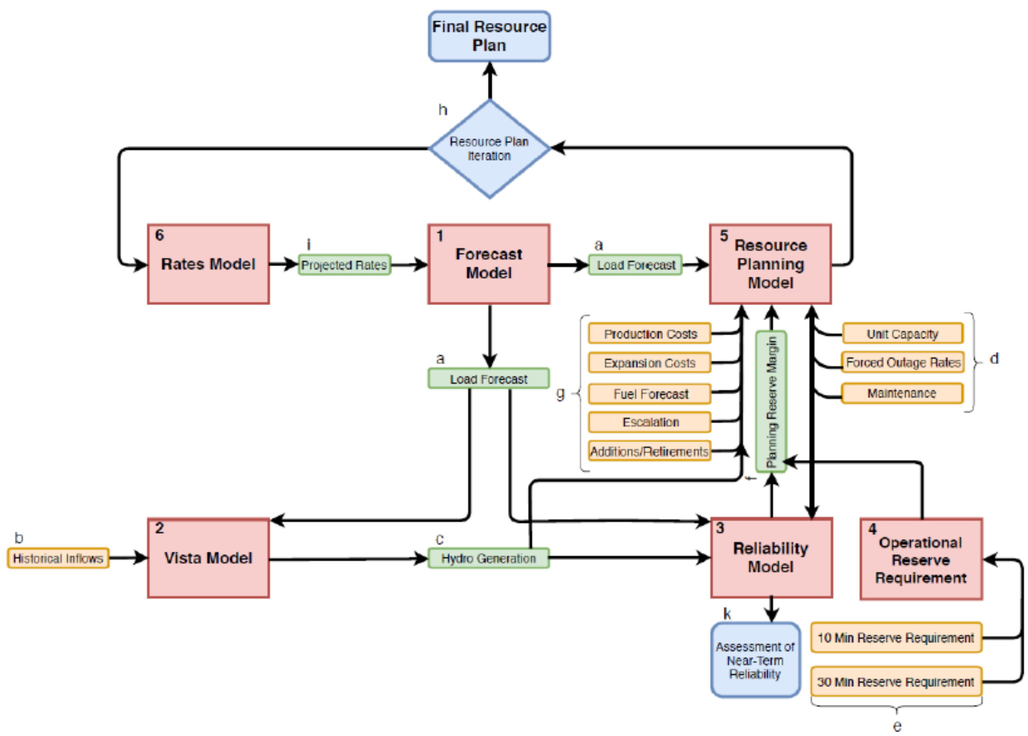
II. Study Methods, Assumptions, and Criteria

A. Study Process

We examined the process and methods by which Hydro has examined its future electrical requirements and means for meeting them. This chapter describes those methods and the assumptions and criteria used to execute them and it presents recommendations for activities that we consider critical to accomplish in the next coming months.

The next figure provides an overall depiction of the process by which Hydro plans resources.[1] It depicts key components of the approach and methods used, and their relationships. We found the study process as the RRA Study described it fairly conventional. Our review of documents detailing the inputs and outputs of the key components found capable execution of a logical and comprehensive process. We found the improvements largely responsive to the past concerns we have raised about Hydro's supply planning. While finding the process well-designed and executed overall, we did observe a number of issues that we discuss below in this report. On the whole, however, the process used by Hydro exhibits significant improvement over its historic practice.

Figure 1- Resource Planning Process Flow Chart



1. Forecast Modeling

Box 1 of Figure 1 highlights the Forecast Model, which produces the load forecast input to Hydro's Vista Model, Reliability Model, and Resource Planning Model. Hydro disaggregated its load forecast components into segments, for development of overall forecasts using a variety of means. The forecast modeling segments and means noted in the Study include:

- Island Interconnected System - - forecasted using econometric modeling techniques and large industrial customer input
- Labrador Interconnected System - - forecasted using historical trend analysis and large industrial customer input
- Rural isolated systems
- Utility load - - Domestic and general service loads; Newfoundland Power and Hydro
- Industrial load.

Assumptions regarding provincial economic activity and electricity rates form key load forecasting inputs. The process treats electricity rates conceptually as an output of the resource planning process. Thus, the process reflects an iterative approach, in which the load forecast of one iteration gets adjusted for significant differences in electricity rates between those assumed at the beginning of and those resulting at the end of the preceding iteration.

Hydro selected multiple rates scenarios for study. Hydro then developed demand forecasts based on these rate assumptions (Box 1 in Figure 1), and proceeded through Box 6 to develop a resource plan consistent with each rates scenario. Hydro constructed four future load alternatives to address electricity demand uncertainty. The first three applied Low, Mid, and High retail rates, respectively. The fourth assumed high growth. For each of the four, Hydro constructed three cases, producing a total of 12 scenarios. These three cases were:

- Base Case
- High Industrial Growth Case
- All 300MW of Churchill Falls recapture ("Recapture") fully absorbed by Labrador growth.

To each of the 12, Hydro applied two measures of weather-driven load, resulting in 24 total cases:

- P50 - - average weather; *i.e.*, half of the estimates in the weather range used exceed the one used
- P90 - - extreme weather; *i.e.*, only 10 percent of values in the range exceed the one selected.

2. Reliability Modeling

a. Hydro's Approach

Load forecasts comprise a primary input to Hydro's reliability modeling, which considers generating unit capacities and assumptions about their availability and outages. Boxes 3, 4, and 5 in Figure 1 depict core elements of Hydro's reliability and resource planning process. Hydro uses PLEXOS, a leading industry model for resource planning. PLEXOS simulates a system of generators, loads, and transmission constraints on a 24-hour, chronological basis. PLEXOS models random generation and transmission outages using Monte Carlo simulation. It calculates various reliability indices, such as Loss of Load Hours ("LOLH") and Expected Unserved Energy ("EUE"). Hydro post-processes PLEXOS output to obtain Loss of Load Expectation ("LOLE"). These measures quantify three values for a given year, as defined by the North American Electric Reliability Corporation, ("NERC"): [2]

- LOLE: expected number of days with firm load shed events

- LOLH: expected number of hours of firm load shed
- EUE: expected amount of firm load shed (MWh).

As a consultant study performed for Hydro described, LOLE serves as the most widely-used approach to addressing reliability, with an LOLE target of 0.1/year typical.[3] LOLE targets consider only peak hours of the days having a non-negligible Loss of Load Probability ("LOLP"). The LOLE metric does not indicate duration of load loss or the potential energy shortfall involved. The LOLH metric considers all hours experiencing risk of insufficient generation. NERC observed that LOLH more accurately assesses adequacy in that it examines all hours. However, NERC also reports that LOLE$\leq$0.1 has become generally accepted; no established target value exists for LOLH.[4]

Hydro models the NLIS as two regions - - Labrador and Newfoundland, with the LIL connecting them. Two subregions exist for each primary region - - Lab West, Lab East, Avalon, and Off-Avalon, connected to Nova Scotia via the ML and to Quebec.

Box 2 in Figure 1 depicts the Vista Model. This component addresses "medium- to long-term water storage and energy generation management that guides water operations, hydrothermal generation, and energy transactions."[5] Inputs to the Vista Model include the load forecast and the hydraulic record of 67 years of hydraulic inflows. The Vista Model optimizes storage and water releases to create an economically optimum allocation of the available water to serve load. Hydro's modeling of hydrological uncertainty properly incorporated a probability distribution for Muskrat Falls. The firm capability of its other hydro stations is not affected by low water conditions, with other hydro generation represented by firm capacity ratings based on low water.

b. Hydro's Principal Reliability Criteria

Hydro has adopted three reliability criteria for resource planning:

- An energy criterion
- An operational reserve criterion
- A probabilistic criterion

The ***energy criterion*** states that, "The NLIS should have sufficient generating capability to supply all of its firm energy requirements with firm system capability."[6] This criterion, which we find standard and appropriate, requires no additional margin above firm energy requirements.

The ***reserve margin*** criterion comprises a central parameter of the resource planning process here, as it does widely in the industry. This margin measures the amount by which total generating capacity must exceed forecasted load, to keep the risk of a supply shortage beneath an acceptable level. Utilities use a variety of probabilistic measures to gauge generation shortage risks, including LOLE, LOLH, and EUE. Hydro proposes to change its planning criteria, which Liberty has previously reviewed. The next table compares Hydro's old and new criteria.

Figure 2 - New Hydro Planning Criteria

Criterion	Old	New
Capacity Criterion	LOLH ≤ 2.8	• LOLE ≤ 0.1 • 296.5 MW
Operational Reserves	240 MW	296.5 MW
Energy Criterion	Supply firm energy requirements with firm system capacity	

The new criterion requiring a calculated value of LOLE ≤ 0.1 sets a more stringent standard in terms of required reserves than did the replaced criterion of LOLH ≤ 2.8. That old LOLH ≤ 2.8 equated to LOLE ≤ 0.2, allowing greater customer impact than does the new LOLE ≤ 0.1. Our August 2016 Report cited Hydro's analysis indicating that its old standard calling for a maximum LOLH value of 2.8 equated to an EUE of 300 MWh.[7]

These new criteria have produced a required reserve margin of 13 percent for the NLIS and of 14 percent for the IIS. Hydro used the replaced criterion in the past to yield a lower total system cost compared to LOLE ≤ 0.1. The next table shows some of the details underlying the new criteria.

Figure 3 - New Planning Criteria Details

Item	NLIS	IIS
LOLE Criterion (days/year)	0.1	0.1
Probabilistic Planning Reserve Margin	13%	14%
2028 Peak Load Forecast (MW)	2,060	1,696
Probabilistic Planning Reserve Margin (MW)	267.8	237.4
Operational Reserve Requirement (MW)	296.5	296.5
Planning Reserve Margin (MW)	296.5	296.5

We note that the value of the operational reserve requirement exceeds that produced via the probabilistic method. Therefore, the operational reserve requirement becomes determinative for supply planning here. Hydro's reliability criteria and how management applies them form key determinants overall and for Muskrat Falls interconnection. Most utilities use the same or similar criteria, but not all apply them in the same way.

c. Use of Contingencies in Reliability Planning

An established planning reserve margin sets a key criterion for resource planners, but transmission planners must consider system contingencies in identifying potential violations of the criteria they use to identify future system needs. These contingencies vary widely in nature and consequence, depending on the utility system under study. Many utilities assume a single contingency, applying what is termed an N-1 approach. This approach seeks a design that occasions no loss of load from any one failure of a system component. Applying an N-2 approach seeks to avoid load loss for a second, simultaneous failure. Highly urban networks provide an example of cases where this significantly higher level of reliability is often used. N-1-1 provides a middle ground, allowing for a time gap between the first and second contingency, during which system operators can re-configure the system to mitigate the risks created by the first failure.

Hydro uses now, as it has done in the past, an N-1 assumption in planning for the IIS and now the NLIS. Loss of a major transmission asset (*e.g.*, a 230kV or a 138kV transmission line, shunt capacitor banks, synchronous condensers or a transformer down for maintenance or lost due to a fault) comprise an N-1 condition. Hydro's planning seeks to avoid load loss under N-1 conditions, but Hydro does not plan the NLIS or the IIS to avoid loss of load under N2 or N-1-1 conditions.

d. LIL Contingencies

Chapter V of this report focuses on the LIL design and particularly on why the LIL comprises a critical facility to consider in connection with the N-1/N-2 distinction. Hydro deems failure of a single pole of the LIL an N-1 condition. However, even a single event (*e.g.*, failure of one of the many structures that commonly carry both poles across the LIL's long overhead run) comprises an N-2 event for Hydro's planning purposes. Therefore, a bipole loss may, without violating Hydro's N-1 planning basis, produce loss of load - - perhaps substantial and long-lasting.

The simultaneous loss of both poles of the LIL will in fact cause significant losses of load under some conditions. We are prepared to accept Hydro's view on a technical basis, recognizing that both an N-1 and N-2 designation can find support on a notional or technical basis. More importantly, however, we do not consider that distinction necessarily determinative in deciding how to consider loss of both poles, given potentially significant consequences. The loss of the bipole can result in a significant loss of load and extended outages for customers. A more robust, quantitative assessment of the risks of bipole outages under extreme weather conditions, of the durations required to restore operation, and of the load loss consequences during those durations forms an as yet missing, but required element in soundly determining the adequacy and reliability of the IIS following interconnection with Muskrat Falls and whether the costs of mitigation warrant some form of providing it.

Hydro assumed a two-week repair period for a major overhead line failure, based on Hydro's response to ice-storm damage since 1967.[8] The data included many longer outages, including one of 63-days to address "seven structures failed with broken conductor" following a Buchans to Massey Drive failure. However, since 1994, the longest repair duration of 14 days covered six Western Avalon to Hardwoods conductor miles. Our August 2016 Report addressed doubt about this 14-day period, "[g]iven that, that a tower collapse is most likely to occur during adverse weather conditions…"[9]

e. Role of the ML

Consideration of IIS reliability needs to examine the benefits and risks that introduction of the ML has brought. Our August 2016 Report observed that Hydro may, under the July 31, 2012 "Nalcor and Emera Inc. Energy and Capacity Agreement" curtail delivery of firm power to Emera following extended loss of both LIL poles or loss of single pole accompanied by other significant losses of transmission equipment. In the event of a pole or bipole trip, the ability to curtail load on the ML can have significant benefit for IIS performance.

The ML exists primarily to provide supply to (not from) Nova Scotia and beyond. A bipole LIL trip calling for curtailment of flow towards Nova Scotia will require operators there to use their reserves to meet their own needs, now augmented by the loss of up to 300 MW of deliveries from the ML in the direction of Nova Scotia. Our August 2016 Report found the ability to count on supply to the IIS from the ML questionable in the absence of a firm arrangement. Now, three years later, none exists today.

Hydro has not as yet offered a basis for concluding that a firm arrangement is in the offing or even likely to come sometime in the future. The ML will frequently provide a source for deliveries into the IIS. A material question arises, however, as to whether it will do so when critical. The answer to that question depends on off-Island circumstances determining whether load and operating conditions on the other side of the ML will permit imports when critical. In bad weather and under peak load conditions, counting on the ML appears subject to what appear to be material contingencies; *e.g.*:

- The need for Nova Scotia to replace the 300 MW of energy it would have received across the LIL and ML before considering NLIS needs
- How much region-wide weather conditions similar to those that threaten extended LIL outages may reduce the excess that others have to offer as they face high loads on their own systems.

f. Island Transmission Constraints Following LCP Operation

Very recently, an external study has added more uncertainty to planning efforts. The TGS May 23, 2019 "Avalon Capacity Study — Solutions to Serve Island Demand during a LIL bipole outage" offered an analysis of the consequences of a bipole LIL outage post-LCP operation, assuming the retirement of the three steam units as generators at Holyrood and of the Stephenville and Hardwoods units. The TGS study considered several other, supply-related assumptions:

- All other IIS generation available
- 300 MW of import power available over the ML
- 105 MW of capacity assistance available
- New Island generation of 298 MW added.

The TGS report indicates that the failure to makes such new generation and capacity assistance available, will, in the event of a bipole LIL outage, leave Hydro with insufficient resources in some high-load IIS conditions, even before considering unavailability of the assumed support across the ML. TGS found load curtailment under some conditions would still prove necessary. With the bulk of IIS load on the Avalon Peninsula, the study found that high power flows in the Bay d'Espoir ("BDE") to Avalon corridor can produce circumstances exceeding Hydro's normal planning rules.

A subsequent fault at identified ac transmission network locations could result in a system collapse, requiring restart and connection of loads across a period that could extend several hours.[10] The TGS study addresses a number of transmission and generation options for preventing criteria violations and for preventing system collapse. The report did not provide quantitative information about the probabilities of the events or the costs of measures to mitigate them.

In July, 2019 Hydro issued a technical note following up on the TGS study.[11] Beginning with the assumption of both LIL poles out of service, it addressed load shedding and voltage instability consequences resulting from a contingency, under the following circumstances:

- Loss of Holyrood, Stephenville, and Hardwoods generating capability through unit retirement
- No additional generation has been provided
- No transmission reinforcement has occurred.

In these circumstances, the TGS and Hydro analyses support the conclusion that the 1,700 MW in supply resources available (with the ML providing 300 MW and all Island generation in operation) could support a total customer load of 1,530 MW. Changing that scenario to remove ML imports found that the 1,400 MW available could only support 1,260 MW of customer load. The circumstances produced under these two cases included:

- With ML:
  - Violation - - thermal overload of transmission line TL201 in the event of an outage to TL217
  - Violation - - thermal overload of TL217 in the event of an outage to TL201
  - Violation - - Transient undervoltage violations for a three-phase fault at Sunnyside
  - Non-violative circumstance - - instability for a three-phase fault at Bay d'Espoir, followed by the tripping of TL202, TL206, or TL267
- Without ML - - thermal overload of TL201 in the event of an outage to TL217.

The Technical Note recommends no generation addition or any transmission reinforcements, but rather the adoption of "Emergency Transmission Planning Criteria." These criteria would permit what would comprise violations under the normal criteria. The Technical Note recommended the following criteria for addressing occasions during which both LIL poles are out of service:

- Permit load shedding to avoid thermal overloading caused by a transmission line outage
- Permit transient recovery voltages to remain below 0.8 pu longer than the normal criteria allow for a three-phase fault - - provided that stable operation is maintained
- Adopt the following operational measures to minimize customer impacts:
  - Adopt commensurate restoration procedures
  - Develop a rapid load shedding procedure
  - Review protection settings.

The Technical Note offered several alternatives to these emergency criteria:

- 230 kV upgrades between Western Avalon and Soldiers Pond
- Reactive support in the Sunnyside terminal station area
- Addition of incremental generation on the Avalon Peninsula

The Technical Note further concludes that consideration of the use of these emergency criteria on a longer-term basis depends on decisions whether to install incremental generation and on its location relative to the Avalon Peninsula.

3. *Determining Operating and Planning Reserves*

Like other utilities, Hydro applies an operational reserves requirement in real-time system operations and a planning reserve margin in resource planning. Hydro derived its operating reserve requirement (Box 4 in Figure 1) from the minimum operational reserves requirement specified by the Northeast Power Coordinating Council ("NPCC"). This regional reliability council has responsibilities for interconnected utilities in the region. The operational reserve criterion requires the availability of two blocks of generating capacity to be brought online, one within 10 and the other within 30 minutes following sudden loss of generation or transmission. This operational reserves criterion derives from two assumptions: (a) other online units can operate at their emergency ratings for a 10-minute period to bring the first block online, and (b) an additional, ensuing outage may require dispatching the second block. Hydro identifies these two required blocks based on its first and second planning contingencies: (a) loss of its largest generating unit, and (b) loss of its second largest. Application of its criteria produced (as we describe below) a total required reserve of 296.5 MW, the sum of the following:

- 10-minute reserve requirement requires 197.5 MW, based on its first contingency
- 30-minute reserve of 99 MW, based on half of its second contingency.

Hydro has determined a planning reserve margin probabilistically, employing the Reliability Model. It calculated LOLE for a given set of existing and planned generation resources and a range of values of demand, then derived a planning reserve margin from value of demand yielding LOLE=0.1. Hydro takes the planning reserve margin as the maximum of the operational reserve requirement and the reserve margin yielding LOLE=0.1. Primary Reliability Model inputs include:

- Load Modeling featuring:
  - Explicit representation of weather-related uncertainty in load
  - Hourly load profiles accounting for Labrador/Newfoundland load coincidence
  - Capacity Assistance Agreement with Corner Brook Pulp and Paper ("CBPP").
- Capacity Modeling:
  - Hydro units modeled with monthly capacities and energy limits representing average hydro conditions
- Thermal and Gas Turbines
  - Gas turbines modeled using MW capability and forced outage rates derived from historical data or the most recent industry average
  - Steam units assumed to retire after LCP comes online
- Variable Energy Resources. The two wind projects modeled using probability distributions of hourly output.
- Capacity Transfers: Imports and Exports
  - Firm transfers only are modeled
  - Exports added as load and imports treated load reduction
  - Only two exports; no imports
- Transmission limits between regions and subregions modeled explicitly
- Emergency Operating Procedures - - no capacity benefits from Emergency Operating Procedures incorporated in Reliability Model.[12]

4. *Resource Planning Model*

Box 5 in Figure 1, the Resource Planning Model, implemented using PLEXOS, evaluates existing resources against the load forecast and planning criteria to determine whether sufficient resources remain available to meet requirements throughout the planning horizon. PLEXOS optimizes the selection and timing of any additional resources required. It does so from among candidate resources specified as inputs to the model. This optimization embeds a simulation of the various options together with the existing generators in PLEXOS, given load forecasts and transmission constraints. PLEXOS calculates the operating costs of the generating fleet, including fuel and non-fuel operating and maintenance costs, and capital costs of the additional resources. New capacity is added to meet the planning reserve margin at minimum cost.

RRA Study Volume III presents key elements and parameters of the province's generating assets and transmission infrastructure, as used in the Reliability Model and Resource Planning Model. It discusses:

- Hydroelectric Generation, including monthly generation profiles
- Power Purchase Agreements, which include purchases from hydro, wind, and cogeneration resources
- Thermal (steam units) and gas turbines, some slated for retirement in the near future
- External Markets, the only firm contract involving sale of a block to Nova Scotia after commencement of the third Muskrat Falls unit
- Capacity Assistance, consisting contracted curtailable loads and emergency customer generation
- Transmission, modeled as outlined in RRA Study Volume I.

We undertook an examination (described in Chapter VI of this report) of generating unit condition, operating history and metrics, remedial actions to address prior issues, and plans and expectations for their upkeep. We did so to validate the assumptions made regarding their ability to operate in line with results generated by modeling their contributions under the many cases analyzed. Our past conclusions and recommendations made to address Hydro's generation planning and operation made this inquiry particularly appropriate.

While we found no reason to question them, we did not examine closely the assumptions about external markets, which the Reference on Rate Mitigation Options and Impacts (the "Reference") currently in process by the Board includes.

Hydro's use of the same distribution for wind generation in every hour within a season may overlook any variation in mean wind generation over the day. However, given the small total amount of wind generation, this issue has little impact on the results. Should wind penetration become greater (in fact, or under consideration as an alternative), Hydro should make adjustments, but we see no material consequence of the current approach in Hydro's circumstances now.

5. *Rate Model*

Box 6 in Figure 1 represents the process of combining the operating cost of the generating fleet, including any resource additions, and the capital costs of those resource additions. This combination drives customer rate impacts. Comparing calculated rates from the Rate Model against the rate assumptions going into the Forecast Model provides a check of the consistency of study results with the assumptions. If there is a significant discrepancy between the calculated and assumed rates, then the rate assumptions need to be adjusted and the entire process repeated. However, in this study, an open-loop process was used to derive the resource plan required to meet the planning reserve margin for each of three different rate assumptions. That is, rather than iteratively adjusting the rate assumptions and working through the process until convergence, the process from rate assumption to resource plan was executed just once for each rate assumption scenario.

6. Considering the Value of Lost Load

Hydro engaged in a stakeholder engagement effort while developing the RRA Study. We consider such efforts generally informative. Their value should increase in an environment strongly influenced by a search for measures to ameliorate the impacts of the very large "dislocation" that will come in rates when they begin to include LCP costs.

Hydro surveyed customers to understand their preferences between reliability and cost.[13] The results, while interesting, do not provide substantial guidance in analyzing specific tradeoffs between cost and reliability here. Decisions like Holyrood's future, or any other post-LCP investment, should follow an explicit balancing of the cost of reliability improvements and the value to electricity customers of the reduced risk of power outages. Quantifying the value of lost load to customers comprises a central element of such an analysis, particularly with respect to issues like mitigating the effects of extended LIL bipole unavailability.

A Christensen Associates[14] review completed for Hydro highlighted significant efforts in estimating the Value of Lost Load ("VOLL") across North America over the past 30 years. We do not agree with their observation that, "despite technological changes in the global economy, the value of lost load has remained relatively constant over several decades." We do not place reliance on such constancy. The review did not include substantial, more recent customer survey results.

Relying on data from even 10 years ago in economies becoming even more critically dependent on uninterrupted power supply is not reassuring. Neither is the application of data gained elsewhere to the unique climatological and economic circumstances here. We consider current and "local" data material valuable in making the rates/reliability tradeoffs that significant new investment in resources would entail. The significant rate dislocation looming and LIL outages falling outside the bounds of Hydro's planning criteria underscore that materiality.

B. Conclusions - - Study Methods, Assumptions, and Criteria

These conclusions seek to address whether the overall framework of Hydro's study and analyses is useful and informative. As the conclusions address in more detail, particular circumstances here make clear that work to be completed in the coming months will have a substantial impact on the identification of resource needs and selection of alternatives for meeting or avoiding those either within, or (like extended LIL outages) just outside them. Subsequent chapters address important drivers of the analysis of future needs, including testing of and adjustments to some aspects of Hydro's considerable efforts to date. However, recognizing that much can and very likely will change as 2019 progresses, we consider it important first to assess the baseline utility of Hydro's work to date in addressing the future.

We believe that the RRA Study does provide an appropriate framework, and these conclusions express how. Nevertheless, when it comes to certain drivers and conditions that bear continuing attention in the next coming months, we believe that Hydro, with prompt attention, can and must address them within the foundation that Hydro's work to date supplies.

1. **Hydro's forecasts provide a sound basis for framing the needed continuation of discussions about future supply resource needs, but those discussions need to accommodate information, analysis, and stakeholder engagement that will become available in the next coming months.**

Future needs, as reflected in forecasts fundamentally drive needs for reliability enhancement. Hydro disaggregated load in an appropriate manner and it considered a range of economic and electricity price conditions. We found that Hydro considered conceptually a sufficient range of load determinants, and constructed a reasonable number of scenarios incorporating that range. Those scenarios resulted from methods and criteria generally consistent with common industry approaches. They provide a starting point for an examination of future resource needs.

However, it must be recognized that plans based on scenarios, driven by present forecasts of electrical requirements may well, and are probably likely, to be rendered inapt over the coming months, which will witness and debate in the Reference proceeding the results of an examination of critical factors that drive those requirements for all utilities. These factors include inducements to add electricity use, changes in demand response and conservation programs and their impacts. Hydro faces another potentially critical factor not so common in utility planning; how demand elasticity will affect usage in the face of a potentially massive increase in rates.

It would be ideal to await the completion of the Reference. By the time those efforts contribute new information and analysis, the time remaining available to address short term needs may become too much compressed. What can be resolved now should be. In other words, considering loads forecasted now against existing resources and making judgments on that basis will best equip all to assess promptly what changes in needs identification and adjustments to alternative solutions will become appropriate.

2. **Continuing to reflect both P50 and P90 weather conditions is important in assessing future system reliability.**

Our August 2016 Report addressed this combined use of P50 and P90 weather assumptions, noting that we did not consider the use of a peak expected to be exceeded in half the years analyzed a prudent planning practice. In 2016 Hydro, following an interim report that we issued to the Board, decided to present analyses on a P50 basis, accompanied by a P90 forecast "as a sensitivity case."[15] Before that change, Hydro used only a P50 forecast. We later, in 2017, commended Hydro's movement from a P50 to P90 forecast, finding it both conservative and appropriate.[16]

We continue to believe, as has consistently been the case, that planning solely to P50 is not sound. Presenting results using both it and P90 provide a sound frame for viewing future reliability risks.

Hydro has continued to depict results under both. This approach has particular usefulness here, given broad concern about post-LCP rate levels. The use of both helps to inform the process of deciding what reliability enhancements are "worth" their costs.

Use of a P50-driven planning basis, while recognizing the consequences of P90 circumstances, provides an appropriate baseline for looking at the uncertainties affecting Hydro's system - - but should advance, not foreclose, further analysis of remaining reliability risks. A P90 forecast suggests that the probability that the forecasted peak will be exceeded in a given year is only 10 percent, compared to a 50 percent probability for a P50 forecast. We continue to consider forecasts using P90 appropriate. However, we also see significant value at present for using scenarios employing P50 to establish a baseline for planning. Two base factors lead us to this conclusion:

- All P90-driven scenarios identified by Hydro involve what may well be considered optimistic factors; *e.g.*, high industrial growth, under rates that will increase greatly after they reflect LCP costs
- Even those scenarios allow some time for consideration of alternatives and for consideration of results from the Reference on such factors as conservation and demand management and price elasticity.

3. Hydro's application of an LOLE≤0.1 criterion is both fairly common in the industry and appropriate, in establishing a baseline for addressing system vulnerabilities, but not in ruling out others.

We do not find fault with Hydro's LOLE ≤ 0.1 criterion, insofar as using it as a foundation for establishing a planning baseline. Certainly, its commonality in the industry gives it strong support. However, it bears mention that such commonality arises in a utility community consisting generally of larger systems that have strong interconnections with neighbors. Larger systems generally mean that the largest supply source (here Muskrat Falls) forms a much smaller portion of the supply portfolio, making loss of that source often less impactful. The additional supply sources generally available through strong interconnections in robust markets also tends to provide a greater range of options to address losses of internal sources.

Limiting assumptions about the status of the system to N-1 conditions in examining the capability to support future electrical requirements reliably is acceptable in planning for the minimum actions needed to sustain reliability, but is not sufficient in and of itself.

4. As Hydro has noted, consideration of sustained bipole LIL outages calls into question whether other non-N-1 conditions bear scrutiny.

We agree, but not in the sense of excluding consideration of a bipole outage as Hydro does but in the sense of recognizing that other contingencies falling outside an N-1 designation per Hydro's approach merit examination.

For example, Chapter V of this report provides our current assessment of likely bipole outage durations, whose accurate measurement we consider a critical factor to consider in planning for the future of the IIS portion of the NLIS. This review examines assumptions about structure failure frequency, the range of possible restoration durations, and relies upon direct inspection and photographic mapping of the route and structures.

On the one hand, a structure failure that brings down both poles simultaneously can be viewed as a single event. On the other, its infrequency can argue against planning for it as one does for other single events. Whichever view one takes, one should begin from the position that N-1 reflects a base planning standard, not the only one that merits consideration. An N-1 condition could be so rare as to call for excluding the need to respond to it if very costly measures are involved. Similarly, even properly labeling as an N-2 condition one that has a shorter return period (greater frequency) and higher reliability consequence should not exclude it from planning consideration - - some N-2 events warrant evaluation, and potentially mitigation measures. Hence our belief that crediting Hydro's designation of an extended bipole LIL outage as N-2 is not the issue of consequence here.

5. **Hydro's planning has not been sufficiently informed by quantitative analysis of extended LIL outage probability and duration range or by consideration of generation options to address the concerns recently raised by the TGS report.**

We consider, as explained, that the LIL will remain subject to much longer bipole outages than Hydro assumes. Any use of emergency criteria on the basis that outages will be of short duration should be re-examined. For most outages, restoration within a day or less will occur. However, outages resulting from overhead line structure failure can last much longer. The propriety of the emergency procedures recommended should be examined in light of the results of our recommended analysis of restoration following such failures.

In addition, the Technical Note acknowledges that generation on the Avalon Peninsula has an impact on the need for and content of the emergency criteria recommended. Given the expense of major transmission reinforcement and the acknowledgement of the beneficial role of generation on the Avalon Peninsula, the Technical Note underscores the importance we place on examining a potential role for the Holyrood units during a LIL phase-in period and indefinitely. Rather than deferring questions about such generation (whether from Holyrood or incremental units), Hydro should expeditiously examine them, beginning now.

Issues raised by the TGS report and the Technical Note include the role of additional generation or transmission upgrades, and how to relate the magnitude of reliability-risk reduction commensurate with the costs of providing it. Issues that warrant further information and consideration include:

- Determining the risks of bipole outages of increasing durations (see the following chapter addressing the potential for extended outages);
- Determining the risks of the next event that could potentially cause a system collapse.
- Determining the costs of those solutions and their impact on rates.

The emergency criteria Hydro has proposed to address concerns addressed by the recent TGS report need to be re-examined in light of the results of examining potential LIL outage durations.

6. **There is a critical need for stakeholders to value reliability risks after the application of mitigation measures available to reduce them, and then to measure that value against the costs of mitigation efforts.**

A seemingly prescient comment, (Technical Note Labrador – Island HVdc Link and Island Interconnected System Reliability) addressed this notion nearly eight years ago:[17]

> *Should the Maritime Link not materialize then the significance of the sudden loss of the Labrador – Island Link becomes more severe. At this point one must weigh the cost of increasing the quantity of installed standby combustion turbine generation on the Island Interconnected System against increasing the return period of the weather loads to 1:150 or 1:500 years and the probability of failure at these higher reliability levels. The exercise is quite complex and requires the utility to have a sound understanding of the value of an outage to each of its customer classes.*

The circumstances now bear a substantial degree of similarity. The ML is physically available, but no firm arrangements for any capacity and energy transfer to the Island have been made. Whatever the return period used to design the LIL was, changing that period no longer remains an option. But an option does exist - - more generation on the Island or extension of Holyrood's life as a generation source (not an alternative that Hydro was willing to consider at that time or at any later time until essentially the present). Under conceptually similar circumstances, the Technical Note, correct then and now in our view, observed that addressing options, now like Holyrood or other generation on the Island, "…requires [Hydro] to have a sound understanding of the value of an outage to each of its customer classes."

Interestingly, when consideration of increasing the return period used to design the LIL continued to exist as an option, Nalcor saw generation as a preferable alternative:[18]

> *The chosen Labrador-Island Transmission Line design provides an adequate level of reliability and an increase in the design standard will not significantly improve customer reliability. As Nalcor stated during the Board public hearings, should a higher level of customer reliability be deemed necessary by the Board, Nalcor believes that the increased reliability can be best achieved through the addition of combustion turbines on the island as opposed to an increase in line design.*

7. Hydro has established a suitably broad range of scenarios for reliability analysis.

Apart from the concerns addressed in the preceding conclusions, which are of first importance, we found Hydro's identification of cases and its resulting number of planning scenarios both typical and appropriate. While we recommend testing and validation, and adjustment if thereby warranted, of some methods and criteria, none of our recommendations undercut the value of using the current analysis as a foundation for examining supply reliability risks, consequences, and solutions.

8. Hydro modeled future system reliability using an industry-standard tool across a range of load forecasts, using soundly based expectations about unit performance and hydrological conditions.

Hydro appropriately used PLEXOS, an industry standard modeling tool. The analyses performed considered generating capacities, availabilities, and outages. We found, as described in a later chapter, a sound foundation for assumptions about unit availability and outages. Hydro followed the typical industry approach of applying both an operating and planning reserves criteria.

As we describe in Chapter VI, Hydro's assumptions about the future use of its generating stations are substantiated and credible for planning purposes. Hydrology comprises a central element of effective planning by Hydro, given its high degree of reliance on water as a source for producing energy. Hydro used an appropriately lengthy hydraulic record, and applied an appropriate model for optimizing water storage and release. Hydro appropriately addressed the need for modeling hydrological uncertainty involving Muskrat Falls, and considered low water conditions in establishing firm capacity of its other hydro units.

9. Hydro has not correctly addressed the relationship between planning and operating reserve margins.

The way that Hydro uses the reliability indices calculated by the Reliability Model in determining the planning reserve margin assumes that, in a shortage event, firm load will not be curtailed until load exceeds available generating capacity. However, some operating margin must be maintained for system stability, even with one or more units in a forced outage, meaning that firm load will be curtailed before load exceeds available generating capacity. That is, load will be curtailed when it exceeds the available generating capacity less that minimum operating margin.

This concept finds recognition in the definition of the base case in the Avalon Capacity Study. There, a minimum operational reserve of 70 MW must be maintained at all times. The 70 MW value reflects Hydro's view of requirements for keeping the system stable under emergency conditions. By this standard, the planning reserve margin needs to be at least the reserve margin required to meet the probabilistic criterion plus 70 MW.

Thus, Hydro's practice of allowing the operational reserve requirement to define the minimum planning reserve margin effectively allows the planning reserve margin and operational reserve requirement to overlap. Therefore, Hydro understates the planning reserve margin required to meet the LOLE $\leq$ 0.1 criterion.

Given that a generation forced outage may last longer than a few hours, perhaps days or weeks, operation of the system at the minimum stable operational reserve seems undesirable for multiple hours on multiple days in a row, and may not meet the NPCC criterion. Thus, whether an additional 70 MW is adequate, or the full 296.5 MW needs to be added to the planning reserve margin or some value in between, needs further investigation and discussion.

On the other hand, Hydro conservatively ignores reserve support that may be available from Nova Scotia, which could have the effect of reducing the needed planning reserve margin. Quebec would offer no support, given the contingency of greatest concern; *i.e.*, a LIL bipole outage. These two factors may offset each other to some degree.

10. Hydro's change from a criterion of LOLH $\leq$ 2.8 to LOLE $\leq$ 0.1. produces a larger level of required reserves, and a corresponding increase in reliability.

An hours-denominated LOLH $\leq$ 2.8 equates to a days-denominated LOLE $\leq$ 0.2. The new criterion permits only half the expected loss of load on the occurrence of contingencies. Our February 2017 Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment noted (at page 4) that the old standard "…adopted a loss of load probability that was effectively double that used throughout North America." The new standard brings Hydro into conformity with general experience.

The change increased the operating reserve requirement Hydro found controlling, because it produced an operational reserve requirement larger than the one determined through probabilistic reliability analysis. Its application produces a 24 percent increase in the old 240 MW reserve requirement, producing a new value of 296.5 MW. As we describe below, however, it remains appropriate to evaluate vulnerabilities that remain, due to Hydro's particular circumstances.

11. Hydro used a common approach for developing its reserve margin.

Hydro took an approach consistent with the NERC effort to promote more widespread use of probabilistic methods and criteria. Some utilities have been using probabilistic methods for more than 40 years. We also find Hydro's ≤ 0.1 LOLE criterion fairly standard, but it remains fair to say that common use, not substantial analysis, underlies it.

Hydro used appropriate tools to model future circumstances relative to its criteria. Hydro made appropriate use of PLEXOS, a state-of-the-art software model to support planning, using generally appropriate assumptions to drive its analyses of future conditions and resources. Hydro's calculations of 13 and 14 percent reserve margins reflect common industry value ranges, but are more marginal when considering the small size and comparative electrical isolation of the province's electrical system.

While common, reserve margins in the range of 13 and 14 percent more typically involve utilities with larger size and stronger electrical interconnection with neighboring systems. The comparatively small size produces less diversity of supply resources; *i.e.*, each unit serves a comparatively higher percentage of demand. Moreover, the Newfoundland Labrador networks will have only two interconnections to electrical systems. Thus, losses of individual units tend to mean less in other systems, and options for addressing such losses from outside are generally greater.

12. We found Hydro's operational reserve requirement of 296.5 MW, based on Muskrat Falls units as the largest contingencies, sound on a province-wide basis, subject to concerns about the consequences of a bipole LIL outage.

Considering a single pole outage as a first contingency (N-1), a contemporaneous outage of the other pole becomes a second contingency. As we discuss below, low-probability but potentially high-consequence circumstances can cause a contemporaneous failure of both poles (for example due to a collapse of structures that carry both poles). We continue, as we have in the past, to have significant concern about considering bipole failures.

Using a LIL bipole outage as a planning basis would call for a greater than 296.5 MW reserve. We believe that simple practicality requires judgment in whether and how to apply the NPCC standard to a system whose contingencies are so large relative to its total demand. The standard nominally requires enough capacity to cover the loss of the largest contingency and half of the second largest. The pertinent question becomes what comprises the largest contingency. Hydro defines its largest contingencies as the loss of a single Muskrat Falls Generating Station unit of 197.5 MW and its second contingency the loss of another of the same size. Electrically, however, the Island's largest contingencies involve the LIL.

Each of the LIL's two poles has a capacity of 450 MW, defined at Muskrat Falls. Power injected into the IIS is lower because of the power loss in the converters, HVdc overhead lines, and HVdc cables. Treating its two poles as the two applicable contingencies would require 675 MW of reserve (450 MW for loss of the first pole and one half of 450 MW for the second pole). The 675 MW amounts to nearly a third of NLIS load.

Should one pole become unavailable, Hydro can also load the remaining pole to 150 percent of its rating on a continuous basis. The loss of a single pole would thus leave the other able to operate at the full 900 MW for up to 10 minutes and 675 MW continuously thereafter. Therefore, the capacity lost to the Island in a single-pole LIL outage would be 225 MW (900 – 675) less losses when no exports over ML are scheduled and less when ML exports are non-zero.

Hydro also can curtail scheduled exports to Nova Scotia over the ML at the time of a LIL outage. Exports to Nova Scotia may be reduced in proportion to LIL capacity reduction.[19]

These factors make it likely that the operating reserve calculation would remain in the range of 296.5 MW, on applying a single pole LIL outage as the largest contingency. However, applying a bipole outage as the largest contingency results in the loss of power to the Island of 900 MW, less losses and curtailable exports scheduled to Nova Scotia.

13. Hydro has correctly concluded that lower hydro forced outage rates support lower reserve margins.

However, we consider it important for Hydro to identify the differences between its system and the systems used for benchmarking its planning reserve margin (Manitoba Hydro, Hydro Quebec). The comparatively small size and location of Hydro's system still may not permit it to produce on an economically sustainable basis the level of reliability that larger, more interconnected systems can enjoy, as was implicit in Hydro's earlier reliability criteria.

14. The ultimate question with respect to supply adequacy becomes more a question of affordability than of parsing planning assumptions requirements or comparability of reserve margins.

As we have noted, the question of planning to address a bipole outage should not turn strictly on whether it comprises an N-1 event or not, or on whether Hydro's reserve margins nominally comport with experience of industry weighted toward larger utilities. An extended bipole LIL outage or the lack of supply diversity (measured by numbers of units and external connections) merit consideration, even when analysis of them satisfies industry-standard planning criteria. Although the risk of a bipole outage may be low, the consequences of the loss of load for customers could be severe with the potential for load shedding for extended periods, as we describe in Chapter V. If economical solutions exist to mitigate risks like those, they should be identified and analyzed. The particular difficulty that exists here lies in determining what "economical" means quantitatively, given what will already be a heavy load for customers to bear when their rates include LCP costs.

Current efforts to address potential future rate mitigation raise questions about reliability versus cost. Others in the industry who have considered that trade-off have sought to value reliability in dollar terms, in order to decide whether the costs to improve it are commensurate. Hydro One in Ontario, for example, has for a number of years used an approach that explicitly calculates an economic trade-off between the cost to customers of unserved energy and the cost of additional investment in measures to reduce it.

Efforts to quantify that value have used a combination of customer surveys and modeling. In the absence of such a VOLL study (sometimes also termed a Value-of-Service, or "VOS" study), an LOLE ≤ 0.1 offers, as we noted, a common-sense alternative. However, a VOLL study, especially given the degree of dependence on the LIL and the coming, steep increases in electricity rates, may have merit here.

C. Recommendations - - Study Methods, Assumptions, and Criteria

These recommendations address measures that Hydro should take to test, validate, and, if shown necessary adjust its analysis in the coming months, recognizing that:

- Determining the forecasts best used for planning will be better informed upon completion of other work now underway in the Reference and its assessment by stakeholders and the Board
- Addressing LIL outages requires more robust, quantified consideration of bipole outage likelihood, duration, and consequences under extreme weather conditions.

1. Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances, and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk.

Whether loss of both LIL poles through a structure failure is considered an N-1 or an N-2 system condition, Hydro needs immediately to analyze a clear set of factors more robustly and quantitatively:

- The return period (frequency) of bipole LIL outages occasioned by factors that will cause those outages to be extended
- The likely ranges (not averages) of durations of outages caused by a variety of significant structure failures (structure numbers and remoteness and multi-location failures from the same weather or other event) under extreme weather conditions
- The LOLE, LOLH, and EUE expected across those durations during peak load times of the year
- The degree (absent a firm commitment for supply across the ML during those periods - - a commitment that Hydro has not secured today) to which the ML, operating in contemporaneous load conditions can be relied upon to supply substantial amounts of energy to compensate for the loss of both poles of the LIL
- The ability of Avalon Peninsula transmission resources to operate reliably without the LIL and with the import of substantial amounts of energy across the ML.

Whether Hydro should plan for mitigation of extended LIL outages remains to be determined following such study. However, the ability to provide that mitigation through generation on the

Avalon Peninsula is clearly one of the alternatives that would deserve primary consideration for doing so. Hydro plans to retire the three Holyrood steam units as generation sources. Its presence, for reasons we will explain, places it among the options warranting analysis, should generation alternatives bear consideration.

In summary, while not contesting Hydro's designation of simultaneous LIL outages as beyond an N-1 condition, we nevertheless consider it necessary to look carefully at the probability and consequence of extended outages and of the role that Holyrood can play in addressing them.

2. **Hydro should promptly commence a stakeholder engagement process to address VOLL, informed by a sound, contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk.**

The cost of obtaining such estimates depends on the size of the sample of customers surveyed or interviewed in each customer class. As we view continued stakeholder engagement as vital to making decisions about utility service in the province, developing meaningful VOLL measures offers valuable structure and focus to what we view as the coming, critical phase incorporating stakeholder engagement.

3. **Hydro should continue to reflect both P50 and P90 weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months.**

The information of importance will include at least more data and analysis of future electrical requirements and about bipole outages, their consequences and potential solutions. Hydro should continue to show results and identify and cost responsive measures under both P50 and P90. We would continue to examine them with a bias toward weather values less likely to be exceeded in any given year, but would certainly remain sensitive to the incremental costs involved. Our view of that tradeoff reflects more common industry views; the material view for the province, however, is that derived from stakeholder engagement and the Board's ultimate views.

Over the next several months, Hydro should calibrate the weather influences incorporated in both its reliability model and its P90 cases. Hydro's system will have more options than were available when considering pre-Muskrat Falls circumstances, as we were in early 2017. It will, however, remain comparatively more isolated than systems typically using criteria like those Hydro has employed. Others, California for example, may use a P50 forecast for determining system-wide resource adequacy requirements, while employing a more conservative P90 forecast for local planning in areas with limited capacity to move energy in from outside sources. The system serving the Island, particularly the Avalon Peninsula, faces such limitations.

With P90 load forecasts remaining important to Hydro's planning, it is important to note that Hydro's Reliability Model already incorporates weather uncertainty. Therefore, it may be that overlaying the P90 cases duplicates some weather effects. Hydro should seek to rationalize the two applications to ensure that it has not accounted twice for weather effects.

4. Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error.

We found that Hydro understates the planning reserve margin required to meet the LOLE $\leq$ 0.1 criterion, but ignores reserve support that may be available from Nova Scotia, which could have the effect of reducing the needed planning reserve margin. Quebec would offer no support, given the contingency of greatest concern; *i.e.*, a LIL bipole outage. These two factors may offset each other to some degree. However, each input should be modeled carefully to determine the resulting planning reserve margin.

5. Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin.

We do not at present have a basis for concluding that this effort will have a significant change in Hydro's results, but providing verification in the next several months that it will not is useful.

III. Long-Term Reliability

The preceding chapter sets forth our principal conclusions and recommendations about the RRA Study methodology and proposed planning criteria. It recommends the actions that Hydro needs to take in the immediate term to provide a sound basis for making decisions that will have important reliability and economic consequences for customers as the province progresses in efforts to find ways to mitigate the very large increases in rates that loom. This chapter addresses a number of aspects of Hydro's RRA Study that bear on longer-term reliability considerations.

Hydro's RRA Study addressed long-term planning (2019 through 2028) conducted to identify least-cost means for ensuring its ability to continue delivering reliable service. The study reflected consideration of a reasonably robust range of possible scenarios and alternatives. It did so, for the first time on an integrated NLIS basis, in recognition of the connection between the Island and Labrador, which LIL operation has created. Hydro also changed its planning criteria, making them more in line with those used by other utilities.

A. Forecasts of Electrical Requirements

Hydro's planning efforts sought to relate expected future loads and usage. The forecasts produced show little change in electrical requirements from the present, as the accompanying chart illustrates. Hydro estimated future requirements using expected electricity rates, which incorporate future LCP costs. Absent mitigation, the introduction of those costs will produce dramatic rate increases, under even optimistic views of the future.

Figure 4 - Hydro's Base 2028 Forecast

Year	2018	2028	Change
Demand (MW)			
NLIS Total	2,047	2,060	0.6%
Labrador	400	396	-1.0%
IIS	1,680	1,696	1.0%
Energy (GWh)			
NLIS Total	9,418	9,495	0.8%
Labrador	2,484	2,491	0.3%
IIS	6,997	7,004	0.1%

The accompanying Figure 4 shows Hydro's base case forecast, which projects essentially no change in demand or energy through 2028. An unusually large degree of uncertainty surrounds those forecasts. Hydro correctly observes that changes in economic outlook can have a substantial impact on electricity requirements. That outlook comprises an important element of efforts in the Reference now underway as part of examining post-LCP revenue-requirement mitigation opportunities. Elasticity of demand, inducement of cost-effective additional uses of electricity, and demand management and conservation opportunities will become important matters for stakeholder engagement.

For the time being, both history and the potential large electricity rate increases coming give us no reason to dispute a forecast that fails to incorporate material growth. As compared with the Island, Labrador appears to offer more promise, given industrial growth potential. However, it is not clear that even information about Labrador offers a convincing foundation for large investments. Nevertheless, despite projecting no growth in its base case, Hydro has addressed the potential for growth, as we discuss in this chapter's Section C below.

Recognizing these uncertainties, we found Hydro's forecasts a reasonable starting point for considering future electrical needs at this time. Changes and sensitivities resulting from other processes before the Board will require consideration of adjustments in forecasted demand and energy values used for comparison with existing resource capabilities and potential shortfalls. What we view as particularly critical now, however, is ensuring that the coming efforts be fully informed by:

- Sound baseline analysis supporting a robust identification of alternatives responsive to emerging information about future electrical requirements
- Critical additions to Hydro's analyses of system contingencies
- Prompt assessment of the need for additional generation capacity, including the ability of the Holyrood generating units to serve as short- or long-term supply alternatives.

B. Alternative Supply Sources

The wide range of resource options Hydro considered for future additional supply included:

- Wind Generation
- Solar Generation
- Battery Storage Technology
- Capacity Assistance and Curtailable Load
- Rate Design and Customer Demand Management ("CDM")
- Market Purchases
- Hydroelectric Generation (new facilities, additional units at existing facilities)
- Thermal Generation (simple cycle gas turbines, combined cycle combustion turbines).

Hydro's study considered alternatives to adding supply resources as well:

- Rate designs to induce changes in customer use; *e.g.*, time-of-use rates
- Customer demand management.

Hydro assumed all of the supply options to be within the province, except for market purchases. Attachments to its Volume III provide data on the various generation options and descriptions of the hydroelectric projects considered. Hydro did not consider continuation of generation at Holyrood for a material period following LCP operation, assuming the 2021 retirement of generation at Holyrood, Hardwoods, and Stephenville.[20]

Hydro also provided brief descriptions of Capacity Assistance, Curtailable Load, Rate Design, and CDM options. It also reviewed time-of-use and critical peak pricing efforts in other Canadian provinces. Hydro and Newfoundland Power offer energy conservation programs under the takeCHARGE brand. The two utilities are currently conducting a CDM Potential Study, following previous studies in 2007 and 2015, to inform future takeCHARGE offerings. Results are expected in August 2019. Nalcor Energy Marketing ("NEM") provided information gleaned from various public sources on power that might potentially available through market purchases from outside the province. No plans exist to explore such options further, until there is a need for new capacity.

We did not find a robust re-examination of extending Holyrood's life, at least until very recently. As we will describe, Holyrood requires consideration as both a short- and longer-term option for addressing contingencies that we view as material to ensuring reliability. The decision with respect to Stephenville and Hardwoods resulted from persistent difficulty in maintaining the units and in assuring continued availability of equipment replacement options. Apart from efforts to get perhaps another winter or two out of them, we found, as we explain in Chapters II and VI, that Hydro has appropriately decided to retire them.

C. Scenarios Created for Analysis

Hydro studied 24 scenarios, using a variety of assumptions about usage, applying its proposed planning criteria and considering more and less aggressive probabilities concerning load and usage across its ten-year study period. Hydro's analysis produced no energy shortfall in any scenario. The analysis, however, identified capacity shortfalls in 7 of the 24 scenarios. The next table summarizes them.[21, 22]

Figure 5 - Scenarios Hydro Identified as Requiring Incremental Resource Additions

Island Load Case	P50 vs P90		Labrador Load Case	Year of resource requirements
Case I: Low Retail Rate	P90	1	High Industrial Growth	2028 (58.5 MW)
		2	Recapture Fully Consumed in Labrador	2023 (117 MW)
Case IV: High Load Growth	P50	3	High Industrial Growth	2028
		4	Recapture Fully Consumed in Labrador	2026
	P90	5	Base Labrador Load	2027
		6	High Industrial Growth	2025 (117 MW)
		7	Recapture Fully Consumed in Labrador	2022 (117 MW), 2028 (58.5 MW)

The table highlights the variables that drive differences among scenario results:[23]

- Peak demand differences driven by the range of IIS retail rates
- Use of Recapture energy in Labrador
- P90 versus P50 peak demand forecast.

In general, it takes a combination of factors to produce a resource addition need, as Hydro modeled this resource in relation to a range of projections of electrical requirements:

- Low retail rates or high load growth on the Island
- High Industrial growth or consumption of all Recapture energy in Labrador.

The first indications of need for resources does not appear until 2026 under scenarios incorporating P50. Hydro's report of its study stated the following about P90 versus P50:[24]

> *… such planning will result in advancement of system expansion. Planning for the P50 peak demand forecast will mean that additional firm capacity currently existing in the system can be used to encourage domestic load growth, with excess capacity then sold to export markets on a declining basis as load grows.*

Hydro's table summarizing scenario results does not directly identify the magnitude of need created under the two P50 scenarios requiring relief, but the study reports a single, 66-MW combustion turbine unit as a solution for each. The Resource Planning Model also selected one or two 66-MW gas turbines to meet the needs of the other, P90-driven cases, with Hydro identifying several other options under consideration:

- Conservation
- Demand Management
- Rate structure
- Alternative technologies; *e.g.*, batteries.

Hydro concluded that, with additional supply unlikely to be required before the mid- to late-2020s, its most cost-effective approach is to:[25]

> *wait until more certainty around utility retail rates, more certainty around potential quantity and timing of industrial Labrador load growth and operational experience with the Lower Churchill Project assets is obtained. This analysis is planned to be revisited annually….*

Hydro therefore proposed an action plan comprised of several near-term elements:[26]

- Inform the analysis of revenue requirements proceeding in connection with the Reference
- Study alternative technologies, such as battery storage technology
- Work with its consultant TGS to examine transmission options for increasing power delivery to the Avalon Peninsula (addressed in Chapter II)
- Analyze alternative rate structures and pricing, supporting Newfoundland Power's rate design evaluation
- Jointly execute the 2018 CDM Potential Study with Newfoundland Power.

Hydro's scenarios show most of seven identified shortfalls arising in the late 2020s. The two most near term (highlighted in red in Figure 5) from among those seven show a need for 117 additional MW of capacity in either 2022 or 2023. Both employed P90 and both assume use of the full Recapture in Labrador. Hydro considers both these two scenarios as falling outside the range of likelihood that utilities generally consider in committing substantial resources to supply asset addition or reinforcement.

Particularly given the load influencing factors now being studied in the Reference, we believe that Hydro's judgment that it should defer a decision on future generation has considerable merit, taking as a given for the moment the accuracy and sufficiency of Hydro's analyses, which we will address below. Hydro has also concluded that the remaining five shortfall indications require no action at this time, but do warrant further study. Their dependence on the same uncertainties about rate levels, Island growth, and Labrador growth also support this position.

D. Conclusions - - Long-Term Reliability

15. Hydro has yet to examine sufficiently the option of reversing its long-standing decision to end electricity generation at the Holyrood steam units.

With one critical exception, Hydro has considered a proper range of future supply alternatives,. Hydro has placed a wide range of options "on the table," but has not identified any for implementation. Ideally, some form of priority ranking of them is desirable, but ranking too is at present rendered premature by the other efforts, mentioned above, now underway. Progression of that work should present a much more clear picture of the potential for and the utility and economy of principal alternatives to new supply capacity, *e.g.*, demand management, conservation, and promotion of cost-effective means to increase electricity use in the province. The dimensions to be provided by this work will prove critical in making properly informed choices about how to optimize the supply portfolio to meet (at the same time) a more informed view of future electrical requirements.

The failure to have robustly examined a future role for Holyrood in the past (a legacy of the commitment to the LCP many years ago) leaves an important gap in ensuring consideration of all the alternatives that may make effective short-or longer-term contributions to system reliability. For reasons we address in Chapter II, we consider it critical to examine analytically and comprehensively now, not only a short-term, but a longer-term role for Holyrood as well. We explain the reasons in that chapter.

We address in Chapter V of this report our concerns about the impacts of a significant bipole LIL outage during its period of early operation and during that period or indefinitely under extreme weather conditions. We believe that longer-term planning for system reinforcement:

- May well be affected by measures undertaken to deal with a short-term bipole LIL loss, should the incremental costs of making those measures longer-term options present economic advantage
- Should incorporate a more robust and quantified consideration of the risks of bipole failure in extreme conditions
- Should incorporate a broader range of LIL restoration times, by considering remote locations, cascading structure failures, and multiple failures of structures in disparate locations.

16. The consideration of alternatives should be informed by the latest information affecting demand forecasts.

Below we discuss details about the studies and analyses underlying Hydro's approach with respect to long-term planning. However, the approach offered by Hydro needs to consider looming economic and electricity rate circumstances that have justly become a major focus of the provincial government, the Board, and the province's residents, businesses, and institutions. In parallel with a review of supply planning, the Board (as requested by the government) is examining opportunities to mitigate post-LCP revenue requirements.

Those efforts provide important context for examining the merits of Hydro's proposed plan to avoid commitment now to added resources. Expensive new resource additions would further increase rates, or, at the least, substantially undercut the savings that the current mitigation review and continued action by Nalcor and Hydro to reduce costs would otherwise produce. These circumstances make decisions facing the province and the Board less a question of fine tuning the factors and assumptions that should drive long-range planning and more a question of what risk-avoiding enhancements are "affordable." We suggest an approach that focuses not on technical arguments about planning techniques, criteria, and assumptions used by Hydro (which we do address in chapter II), but on:

- What are the reliability-related risks
- What options exist to change the identified reliability-related risks
- What changes in reliability they will produce
- What costs they will require
- How should reduction in reliability risks be valued, for measurement against the costs of producing them.

Such an approach will place supply planning questions in the context of deciding what rate path (after mitigation) should be sought. Reducing reliability risk through resource additions is, effectively, one more cost source that should be "on the table" in that exploration of the path of future rates over a period that will bring higher rates to the province.

Moreover, the revenue-requirements mitigation efforts are addressing many factors that can influence future demand and use. Those factors include, for example, demand elasticity, alternative rate structures, demand and usage reduction options, and potential inducement of certain types of electricity use. Consideration of the results of that work may have significant implications for the forecasting that underlies Hydro's supply planning, adding another reason for examining supply planning with the benefit of results from the rate mitigation opportunity work and the substantial value that stakeholders will add when their opportunity to address the factors involved comes. The elements of Hydro's proposed near term approach correctly focus on ensuring a fully informed, robust review of such matters.

E. Recommendations - - Long-Term Reliability

6. Hydro should establish a plan and schedule for integrating the results of the current examination and subsequent processes for considering factors affecting future electrical requirements and non-generation means for influencing load and usage into a re-analysis of its future needs under a robust range of circumstances and scenarios.

Using the best information now available, Hydro should prepare a plan and schedule describing how and when it can incorporate such results into a revised set of planning scenarios, assess the reliability consequences of those scenarios, identify the size and timing of remaining needs, and form its recommendations for addressing them. The schedule for these activities can timely incorporate, as it should, all of the recommendations we make in this report in a time period consistent with other, ongoing efforts that may substantially affect decisions about future system reliability and economy.

We believe this approach to be similar in practical effect to what Hydro has proposed. However, it is critical to establish the shortest possible schedule for completing the efforts required, in order to expedite determination of the best course of action and to ensure that sufficient time remains to implement either temporary measures requiring fast response or long-term measures requiring long lead times.

Another important feature that requires consideration, as we explain in Chapter III, is that temporary needs (*e.g.*, such as might be required during a relatively short LCP phase-in period) may call for facilities or measures that may not, on their own be optimum for the long term. Nevertheless, once adopted for short-term purposes, the incremental efforts to make them long-term solutions may be small enough to make them more competitive or superior to other long-term solutions.

We recommend an economic analysis that provides a direct comparison of the costs of reliability-risk reduction options with the dollar value of the level of risk reduction produced. This effort, not unprecedented, will require a means for:

- Clear delineation of the nature and quantitative magnitude of the reduction in risk
- A quantification of the costs of producing it
- Assigning a dollar value to that risk reduction in a manner that permits direct comparison to the costs of producing it
- A process for robust stakeholder participation in challenging that comparison, to support a well-informed final decision on the merits of committing to resource additions.

7. Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply resource.

It is not yet possible to determine whether Holyrood has a short- or long-term role, but that is because Hydro historically has ruled it out as an option. Circumstances compel prompt completion of that analysis. See Chapter VI for details.

IV. Near-Term Reliability

A. RRA Study Results

Volume II: Near-Term Reliability Report presents the results of Hydro's examination of reliability for the 2019 through 2023 period. It outlines work done to address recent reliability issues with generating assets, including hydro, thermal, and gas turbine units. It also includes an analysis of system reliability over the 2019-2023 time frame, conducted consistently with the format described in the NERC "Probabilistic Assessment Technical Guideline Document." Key inputs to this analysis include:

- Generating asset outage rates
- Asset retirement plans
- Load forecast, specifically:
  - Case I: Low Retail Rate forecast for IIS
  - Base and High Industrial Load Growth cases for LIS.

Hydro also described measures taken to increase energy production over winter 2018-2019, including economy energy imports over the ML to allow hydro generation to be backed off in the fall and increase storage in reservoirs going into winter.

The next table summarizes the results of six scenarios that Hydro examined.[27] Note that the term "N/A" in effect means no change from the corresponding LOLH entries shown for the preceding scenario. Hydro did not provide LOLE measures, choosing instead to report LOLH values.

Figure 6 - Annual LOLH for Short-Term Scenarios Analyzed in 2018

LOLH (hours)	2019	2020	2021	2022	2023
1 - Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	2.56	0.61	0.05	0.23	0.36
2 - Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	2.21	0.59	0.05	0.23	0.37
3 - Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	3.31	0.91	0.05	N/A	N/A
4 - Increased Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 20%	4.13	1.15	0.04	N/A	N/A
5 - Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	2.25	0.61	0.07	0.32	0.61
6 - Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2019, Holyrood DAFOR = 15%	4.61	N/A	N/A	N/A	N/A

The first scenario provides a baseline, assuming the present level of capacity assistance, the base Labrador forecast, and a 15 percent Holyrood DAFOR ("Derated Adjusted Forced Outage Rate"). DAFOR measures the percentage of time that forced circumstances cause a unit to be unable to operate at its maximum continuous rating. A traditional forced outage rate simply measures the time the unit is off versus on, giving the unit full credit for operating even if it is available at less than its full capability. On the other hand, DAFOR gives only partial credit when the unit is only available at a reduced amount. For example, if a unit is forced to run at only 75 percent, 25 percent of the associated hours count as a forced outage. Thus, accounting for circumstances that leave the unit still able to operate at a reduced level, DAFOR reflects a more useful, equivalent forced outage rate.

The second scenario adds to the first the effects of a Hydro contingency plan (submitted to the Board on October 1, 2018). This submission set forth Hydro's measures for mitigating the consequences of delay in LIL operation. This two-phased contingency plan would add a total of 65.1 MW, as follows:

- Phase I (total, 53.6 MW)
  - Increase of Capacity Assistance from 90 MW to 110 MW (later reduced to 105 MW[28])
  - Reinstatement of Capacity Assistance Program
  - Reinstatement of Load Curtailment Program
  - Voltage Reduction
- Phase II (total, 11.5 MW)
  - Increased output of Holyrood Gas Turbine beyond current base assumption
  - Temporary increased output of Holyrood Diesels.

The third and fourth scenarios show the results (assuming the contingency plan) of increasing assumed Holyrood DAFOR from the 15 percent assumed in the first two scenarios - - first to 18 and then to 20 percent. The fifth scenario adjusts the second, contingency plan scenario by employing a high Labrador load forecast, keeping Holyrood DAFOR at 15 percent. The terms describing the third and fourth scenarios differ, but their only difference is in the amount by which Hydro increased the assumed Holyrood DAFOR.

Of particular note, the sixth scenario shows the major impacts of a LIL delay to mid-2019.

The 2022 and 2023 N/A entries for the third and fourth scenarios appear because Hydro continued to assume retirement of the Holyrood units by that time (*i.e.*, upon Muskrat Falls operation). The N/A entries for the LIL delay scenario appear because Hydro assumed a LIL operation delay only to mid-2019 and did not consider extended LIL outages as part of its planning. We will address the basis for that omission in a following section of this report.

As noted, Hydro uses LOLE, not LOLH, as a planning basis. PLEXOS runs do not directly calculate LOLE. Hydro post-processes PLEXOS results to calculate LOLE. Its analysis equates LOLE = 0.1 to LOLH = 0.6[29], making the latter value the one for interpreting results. Hydro did not offer material interpretation of the results shown in the chart.

B. Recent LIL Schedule Information

We recently conducted the latest in multi-year series of quarterly meetings with Nalcor and Hydro to address LCP transition to operations. In addressing the transmission component, Nalcor reported that, "The largest outstanding risk remains the development and delivery of Bipole software." The presentation provided for that meeting observed that low-load LIL testing has been delayed by nearly two months - - to January 2020.[30] There is also no "float" in the schedule for reaching that milestone. Even when reached, there is no assurance that reliable bipole operation will commence shortly thereafter, as winter months continue.

There appears to be no plan to consider returning to monopole option to address the delay of LIL operation into and quite possibly beyond the coming winter season. First, the contractor has had, in effect, to undo work required to get to monopole operation, in order to prepare for bipole operation. There may no longer be time to reverse that course to permit monopole operation before this winter.

Information from the RRA Study shows, as noted in the preceding chart that LIL unavailability through mid-2019 would have produced LOLH outside the limits of Hydro's planning criteria. That chart illustrates the results of a LIL delay through mid-2019. With a longer delay now planned, we turned to a report from Hydro in May 2019, at which time Hydro projected a November 2019 LIL in-service date.[31] The next table[32] shows results provided in the May 2019 Hydro report.

This table shows what was considered then a contingency affecting the base, or "Expected" case; *i.e.*, a LIL bipole outage from May 1, 2019 to June 1, 2020. The latest schedule showing low-power testing commencing in late January 2020 makes a no-LIL case for the coming winter a more "expected" case than a potential one. Were it chosen as the Expected Case, the 2020 LOLH of 2.64 approached Hydro's old, now superseded criterion of LOLH≤2.8. If Holyrood's DAFOR is increased from 15 percent, then the reliability criteria may be exceeded.

Figure 7 - Reliability with a LIL Delay to 2020 - - Reported in May 2019

LOLH (hours)	**2019[19]**	**2020**	**2021**	**2022**	**2023**
S1: Expected Case; Base Assumptions, Holyrood DAFOR = 15%	0.09	0.07	0.10	0.22	0.32
S2: Increased Capacity Assistance, +8 weeks unavailability of LIL, Holyrood DAFOR = 15%	0.09	1.35	0.10	N/A	N/A
S3: Increased Capacity Assistance, +8 weeks unavailability of LIL , Holyrood DAFOR = 18%	0.11	2.03	0.09	N/A	N/A
S4: Increased Capacity Assistance, +8 weeks unavailability of LIL , Holyrood DAFOR = 20%	0.13	2.59	0.09	N/A	N/A
S5: Increased Capacity Assistance, LIL Outage May 1, 2019–June 1, 2020, Holyrood DAFOR = 15%	0.78	2.64	N/A	N/A	N/A
EUE (MWh)	**2019[19]**	**2020**	**2021**	**2022**	**2023**
S1: Base Assumptions, Holyrood DAFOR = 15%	3	3	8	17	26
S2: Increased Capacity Assistance, +8 weeks unavailability of LIL , Holyrood DAFOR = 15%	3	70	7	N/A	N/A
S3: Increased Capacity Assistance, +8 weeks unavailability of LIL , Holyrood DAFOR = 18%	4	107	7	N/A	N/A
S4: Increased Capacity Assistance, +8 weeks unavailability of LIL , Holyrood DAFOR = 20%	5	141	8	N/A	N/A
S5: Increased Capacity Assistance, LIL Outage May 1, 2019–June 1, 2020, Holyrood DAFOR = 15%	42	135	N/A	N/A	N/A

C. Conclusions - - Near-Term Reliability

17. Hydro's analysis establishes that pre-Muskrat Falls vulnerabilities remain very substantial, as they have now for some time.

Hydro's reliability probabilistic criterion is likely violated in 2019 in every scenario, even with the LIL in service for the 2019 winter. The situation improves very substantially beginning in 2020, with the LIL in operation and a Holyrood DAFOR not greater than 15 percent. Following full in-service of LCP, much reduced values of LOLH and EUE occur in winter with at least one pole of the LIL in operation.

While we have no reason to question the sufficiency of Hydro's efforts to address immediate-term contingency measures, they have only a small impact on expected reliability, for example reducing LOLH by about one-seventh.

The most notable information provided in connection with near-term reliability is that LOLH nearly doubles, should Holyrood thermal unit DAFOR increase from 15 to 20 percent, even with increased capacity assistance. This result illustrates the importance of Holyrood as a supply source if power from Muskrat Falls is not available.

Hydro's analysis also showed only a small difference in the immediate term when assuming high versus base Labrador forecasts, in effect minimizing a factor that has greater long-term significance according to Hydro's study.

18. Before the latest information about LIL schedule, we concluded that Hydro's contingency plan will produce marginal reliability benefits for the short-term, but has much less significance to reliability than does LIL and Holyrood performance.

Hydro provided very little interpretation of the results of the table summarizing LOLH under the seven scenarios depicted in the table taken from its RRA Study (depicted in Figure 7). Still, some significant observations result when applying an LOLH = 0.6 as equivalent to LOLE = 0.1. Every scenario produces hours about four to eight times those permitted under the criterion.

With little more apparently to be done to find new short-term sources, the results also showed that even small changes in Holyrood performance have a much greater impact than do the elements of the contingency plan. As important as Holyrood is, the data also show unsurprisingly that LIL operation has the greatest short-term effects. In the immediate term, therefore, it remains clear that focus needs to lie on reaching reliable, single-pole LIL operation and high availability at Holyrood.

19. The latest LIL schedule information compels a detailed assessment of the impacts of LIL absence on reliability for the coming winter.

The May 2019 near-term reliability report does not give comfort about reliability for the coming winter, as the preceding chart demonstrates. Monthly detail for the months of December 2019 through March 2020 highlight the significance for this winter. That detail shows total LOLH of 3.1 and 168 MWH of EUE.[33] Hydro clearly needs to provide an updated analysis using "no-LIL" as the Expected Case, analyzing contingencies like those incorporated into the May 2019 near-term reliability report, and clarifying assumptions about ML contribution.

20. The impacts of Holyrood and the LIL on reliability, as shown in Hydro's short-term scenario analyses raise important considerations for longer term planning.

Ensuring that high Holyrood availability has short-term importance should raise substantial concern for units scheduled for retirement, and therefore presumably not a focus for investments that may benefit performance, but take many years to pay back. Chapters II and VI explain why we believe, based on what Hydro knows at this point, that it is necessary to consider carefully, analytically, and quantitatively keeping the Holyrood units available as generation resources for at least a several-year period beyond full LCP operation, if not indefinitely. The data show a need, without considering future usefulness, to maximize its availability for the remainder of 2019, and presumably 2020 as well in the event of further Muskrat Falls delay. None of the four units at Muskrat Falls will be available for the IIS in winter 2019 and the last one comes online in third quarter 2020. Clearly, the availability of power over the LIL has great importance, even without Muskrat Falls in service.

D. Recommendations - - Near-Term Reliability

8. Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter.

Hydro should establish through study similar to that undertaken under the RRA Study for near-term reliability the consequences of the absence of the LIL in at least monopole operation this coming winter. This study should not merely assume support from the ML, but should quantitatively assess the likelihood and magnitude of support from the ML being available when required at times of high load.

9. Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now.

These results underscore the critical importance of Muskrat Falls, and especially the LIL to reliability in Newfoundland, and the importance of the Holyrood thermal units, without Muskrat Falls or the LIL in at least monopole operation.

We have been monitoring Muskrat Falls and LIL Transition to Operations ("TTO") program and activities for some time. Those efforts continue, and will produce recommendations that we find appropriate for getting the LIL into reliable operation - - both now in monopole mode and eventually in bipole mode.

We do not question the importance that Power Supply management has placed on addressing LIL issues, especially lingering problems with the GE software on which reliable operation depends. Nevertheless, those problems continue to defy solution, to the extent that Nalcor considers the GE software a paramount LCP completion risk.

Similarly, our discussions with Hydro management responsible for the generating units disclosed a focus on Holyrood operations and a clear recognition of its importance pre-Muskrat Falls operation. There also appears to be a recognition of the merits of performing analyses of Holyrood's condition, potential reconfiguration, and longer-term capital expenditure requirements. However, that recognition needs to turn immediately into commitments, plans, and schedules for completion well before the end of this year. Moreover, Hydro needs to ensure commitment to what it takes to keep Holyrood reliable in the next year or so, whatever views drive its planning for the units on a longer-term basis.

V. Extended LIL Outages

A. Background

We examined the potential for extended LIL outages, given its role in ensuring service reliability and continuity. We examined Hydro's extensive study of LIL outages, met with personnel responsible for LIL design and operation, conducted site visits to LIL facilities, met with and viewed facilities at Soldiers Pond, undertook an examination of pictorial mapping of all LIL structures and roads accessing them, and made physical inspections of surrounding terrain and vegetation characteristics generally and a number of structures and access roads at eastern and western locations on the Island specifically.

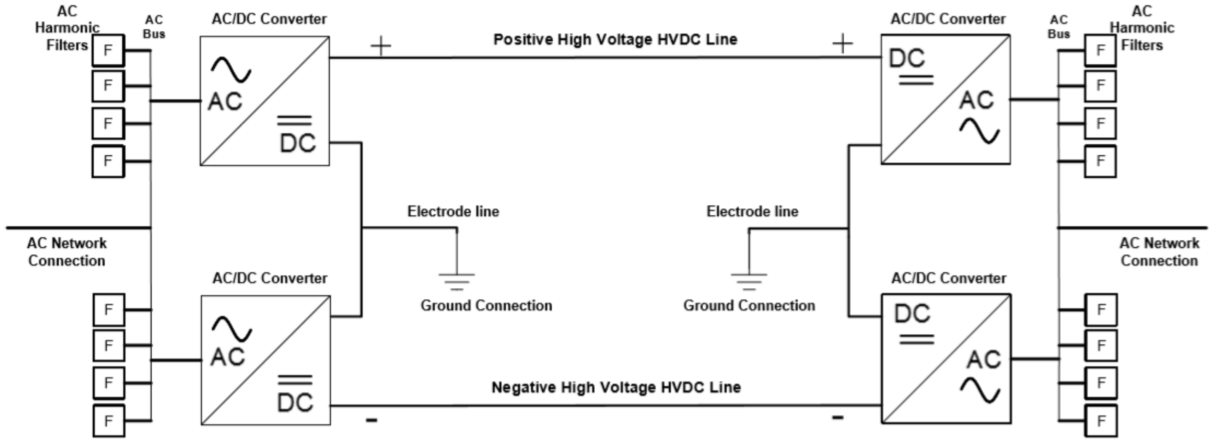
We reviewed Power Supply's matrix of outage threats and impacts, seeking to develop our own view of potential outage durations during peak load conditions, when operation of at least a single pole has the greatest importance in ensuring service continuity. Our consideration of likely restoration times in the event of a bipole outage considered both the time to gain access to the line and the time to provide the bypass planned to secure temporary operation of a single pole pending more permanent repairs. We did so assuming weather conditions that would substantially inhibit access to structure locations requiring bypass.

We also examined other factors that can have an impact on restoration times; *e.g.*, staffing, spare critical equipment, equipment and materials staging, LIL emergency preparation and restoration procedures, and emergency response exercises.

1. DC Line Configuration

Structurally, an HVdc overhead line looks similar to a normal HVac transmission line, and operates subject to the same risks imposed by external factors, like terrain, weather, geology, and other interactions with its immediate environment. Line integrity for both technologies is also subject to design and construction quality. There are, however, significantly different technological features. This section provides a brief and simplified description of HVdc transmission, which links Muskrat Falls to the IIS. The next diagram shows a simplified configuration of a bipole HVdc line operating as the LIL will in its bipole mode. It began operating in monopole mode in June of 2018.

Figure 8 - Simplified Bipole HVdc Line Configuration



An HVdc scheme like the LIL delivers electrical power between two stations that convert its energy to alternating current. HVdc converter stations at each end of the LIL perform these conversions, from ac to dc at a location in Labrador and back to ac at Soldiers Pond. The ac/dc converters are also connected through Electrode Lines to Ground at locations remote from the converter stations. The Electrode line is energized at a much lower voltage than the HVdc line, therefore requiring much smaller structures to carry it overhead.

The conversion process creates on the ac side a voltage requiring cleaning by ac harmonic filters, to avoid ac network problems. Permanent faults in an HVdc scheme's converters, in the HVdc Line, or in the Electrode lines result in the loss of all power transmission capability, until the fault has been repaired. This performance is similar to that of a single circuit ac line. Bipole HVdc schemes like the LIL uses have many components that can fail occasionally. These schemes therefore require steps to reduce the number of outages caused by converter faults. Examples include multiple control systems, converters, and harmonic filters to provide redundancy. Our August 2016 Report provides additional detail about dc line design, configuration, and coordination with an ac system.

2. Notable LIL Design Features

LIL design includes a number of aspects aimed at maximizing the reliability and availability of the power delivery from Muskrat Falls to the IIS. LIL's design as a bipole comprises the most important of these aspects. The LIL bipole HVdc scheme consists of two identical poles. Measured at the Muskrat Falls converter terminal each pole can:

- Deliver the rated power of 450 MW continuously
- Provide a 10-minute short-term overload capability of almost 900 MW
- Provide a continuous overload capability of 675 MW.

Hydro has designed each LIL converter station pole (excluding the HVdc overhead line and the HVdc underwater cables) to meet specified reliability requirements of less than five outages per year, or a total of 10 per year for the two poles. Failure rates for complex equipment, such as HVdc converter stations, typically follow a "bath-tub" curve, with more failures during the very early and very late ends of the lifetime, as compared with the long middle period.

A fault tripping or requiring shutdown of one of the two poles will produce an almost instantaneous increase on the other's power export from Muskrat Falls, making loss of one pole not noticeable on the IIS. Standby generation will commence within the 10-minute period, allowing power flow over the remaining pole to reduce to less than its continuous overload capability. Therefore, a trip of one pole will not cause operation of the Under Frequency Load Shedding ("UFLS") relays, and will not affect consumers.

The time taken to restore the tripped pole to operational status depends on the type of fault and on the responsiveness of the operator and of any crew response required. Some faults may require only brief investigation and resetting of protections executed within a few hours. However, faults requiring equipment replacement will typically take longer, particularly for large equipment, such as heavy reactors and transformers. Where possible, equipment critical to operation (*e.g.*, control system, valve cooling plant, the converter valves, and auxiliary power) employs on-line redundancy to meet reliability criteria.

Hydro has also designed the LIL converter stations to meet a simultaneous bipole failure rate of 0.1 (meaning an average period of 10 years between bipole failures). This rate excludes incorrect operator actions. It also excludes HVdc line failures. Data from EFLA Consulting Engineers ("EFLA"), a consultant retained by Hydro, shows the annual number of bipole outages caused line failures at 0.2 per year. Independent events in which one event causes one pole to trip and another, later, event causes the other pole to trip before the first pole has been returned to service can also produce a bipole failure. Hydro does not consider these non-simultaneous, independent events as "bipole failures" for planning purposes, assuming sufficient time between them to restore the first pole before the second is lost

A bipole failure will result in the instantaneous loss of all power transmission on the LIL. It will also likely cause operation of UFLS to prevent system collapse, if the power is higher than the reserve margin and the support from the ML is unavailable. When the ML is available and in frequency control mode it can provide beneficial power support to the IIS upon loss of the LIL.

Lightning strikes will cause the LIL's HVdc overhead line to experience a number of faults. These faults will usually clear automatically through operation of the HVdc control system. The synchronous condensers will maintain the system frequency above the UFLS setting level. Therefore, excepting a brief dip in lights (because of low voltage), faults caused by lightning will usually prove insignificant. If a first attempt does not clear the line fault, a second attempt will typically follow, allowing a longer duration for clearing ionized air at the fault location. This second attempt may result in some limited UFLS, depending on system load, and whether the power on the other pole has been increased. If the second attempt fails, a third may follow, typically at reduced dc voltage, potentially causing further UFLS. Should these attempts fail, the affected pole will be shut down and the other pole will pick up the power previously carried on the failed pole.

The HVdc line may also suffer other weather-related faults (*e.g.*, due to very high winds, icing, and rime frost). Although the likelihood of failure due to these causes is low, the outage durations they can produce make consideration of them important. An example of a worst-case event would be a structure failure producing a cascading series of failures at contiguous structures. A bipole failure would result. Restoring line operation would require extensive work at the structure locations affected, with outage duration dependent on weather, location, and other factors. Hydro has assumed a worst-case scenario to require two to three weeks to restore operation of a single pole.

The LIL's operation relies on a ground return conductor that runs from the converter stations to the sea electrodes. The return creates another vulnerability to a bipole outage. The Labrador portion of the ground return is unusually long (because of the location of the sea electrode). It runs for most of its length above the HVdc conductors. The ground return line on the Island is much shorter. Breakage of the ground return conductor can cause a fault that would result in a bipole trip. Hydro's calculation of bipole outage probabilities has not considered this event. Doing so would generate a greater number of predicted bipole trip events.

The crossing at the Strait of Belle Isle employs three sub-sea HVdc cables, each rated at 450 MW. Two operate in parallel on one pole, with the third cable connected to the other pole. Proper design and installation of these cables makes the likelihood of their failure due to electrical stresses very low - - allowing the potential for more than one of them to fail essentially to be ignored. Most HVdc cable failures result from impact (*e.g.*, during cable laying, with damage not becoming evident until many months after entering service), from ship anchors, or from icebergs. Hydro has engaged consultants to determine the risk of cable hits from an iceberg. The analysis showed that the return period for such an event was higher than 3,000 years. The time to repair a failed cable can be very long because of ice conditions in the Strait, which may make it impossible to access the failed cable during the winter months.

3. *Early LIL Operation*

A change in plans to energize one pole of the LIL earlier has produced power flows for some months now. That operation has produced a number of trips and continuing delays in events key to its commissioning. We do not consider this experience necessarily an indicator of long-lasting flaws or problems, although that experience does bear on the efforts and duration remaining to complete commissioning of both poles. If each of the trips experienced undergoes detailed study and if their root causes are addressed by the manufacturer, it is reasonable to expect long-term operation of the LIL to meet standard industry levels of performance and the specified reliability criteria.

4. *Observations About LIL Outages*

Most bipole outages resulting from issues associated with converter station equipment will cause UFLS, but it will normally be possible to restore one pole to operation within a few hours or a few days. Natural disasters (*e.g.*, earthquakes or fires) that affect both poles comprise an exception. While very low in probability, they can produce outages of multiple months.

Bipole outages caused by the HVdc converters should typically produce infrequent outages and durations of up to two days. Longer duration outages caused by the HVdc converters could result from latent defects, possibly not discovered for as long as several years after entering service. This result occurred in the industry some years ago, when many converter transformers started to fail because of pre-mature aging. Prolonged bipole outages could also be caused by fires, extreme weather events, earthquakes, or malicious actions affecting both converter poles. Severe weather and other events could cause lengthy outages of the HVdc overhead line.[34] The extremely unlikely event of a failure of all three HVdc cables could take the LIL out of service for several months.

Consideration is now being given to delay the retirement of steam generation at Holyrood for a period after commencement of LIL commercial operation. It is important to undertake that examination with a clear understanding of:

- What it will take to give the units involved the capability to do so - - that examination remains to be performed; it should proceed promptly
- The changes and their costs for giving them the capability to respond across a range of durations (material to addressing the degree to which they can avoid or limit the duration of UFLS). Again, it is important to study those costs, the unit response times that will result, and what reliability risk reduction benefits those times will produce in the event of bipole LIL outages.

Should the examination find short-term risk-reduction benefits that are considerable, in relation to the costs of producing them, it may become pertinent to look at the units involved over the longer term as well. One factor in such an analysis will consist of an examination of the incremental investment and of the operating costs of enabling the units to operate not just for several years, but indefinitely. The potential for a longer-term future for assets like the Holyrood units may also affect circumstances and alternatives being considered in the Reference.

B. Planning for Bipole LIL Outages

Planning for bipole LIL outages requires assessment of the risk of their occurrence and the consequences that may result from such occurrence. The overhead line portion of the LIL presents, in our view, the most significant vulnerability in this regard. This is so because an outage in adverse weather threatens both to prolong the duration of the outage and to coincide with peak demands for electricity.

For Hydro, ice loadings comprise a primary threat to overhead line operation. For the same location, the same would be true for an ac transmission line, given that the effects of weather are similar to both. Risk to loss of overhead transmission lines is most commonly measured in terms of a return period - - commonly expressed as the number of years in which a disruption may be expected. Hydro generally designs transmission lines to a return period of 1:50, meaning one expected occurrence in 50 years, or a two percent chance of such an occurrence in any given year.

Hydro's Volume III described its "Additional Case Analysis: Supplying Customers in the Event of the Prolonged Loss of the Labrador-Island Link" (section 6.2). The report observes that the design of the LIL meets 150- and 500-year ice and wind loading criteria, depending on region, but that statement needs to be examined with reference to the source of those criteria.

We do not take issue with an assertion that Hydro's LIL design produces such long expected return periods between failures when measured by the standards of the CSA Group (formerly the Canadian Standards Association). However, those standards incorporate ice and loading conditions less severe than those that Hydro has identified as applicable to the specific area in which its facilities operate. The CSA Group standards recognize the potential for more severe conditions than those underlying its return period calculation bases, and endorse the use of more severe weather conditions in facility design if local conditions warrant.

Accordingly, the same design that produces a 150- or 500-year return period under the CSA Group standards will produce a shorter return period under Hydro's meteorological conditions. Therefore, in determining the likelihood of a LIL structural failure, Hydro should use local conditions where more severe than those embodied in the CSA Group standards. We are given to understand that certain portions of the LIL have been designed to account for local conditions. Nevertheless, it remains important not to base outage probability calculations simply based upon CSA standards. Hydro should assess outage likelihood on the basis of weather conditions where the line runs. In any event, Hydro considered a bipole LIL outage resulting from a structural failure too unlikely to provide for relief from other sources in the event of such failure.

In addition, we believe that the range of possible bipole outage durations resulting from structural failures requires substantial analysis. Hydro's RRA Study addresses the consequences of a scenario in which it faces loss of both LIL poles for three weeks during January. The three-week bipole LIL outage duration corresponds to Hydro's expectations about likely LIL restoration times. Hydro's analysis of such an event shows that loss of both poles of the LIL during winter would produce a generation shortfall on the IIS when load exceeds 1,400 MW. Transmission system limits would restrict deliveries to the Avalon Peninsula from the west or across the ML. The report stated that:[35]

> *… if a three-week outage were to occur at time of system peak, __**heavy rotating outages**__ affecting __**up to a third of the population**__ at a time could be expected for __**up to seven days**__, with rotating outages of lesser magnitude and shorter duration outside that time.*[emphasis added]

The RRA Study report states with respect to a bipole outage that:[36]

> *As such, in the current transmission system, neither the existing capacity assistance contracts nor supply over the Maritime Link would help mitigate the capacity shortfall in this considered scenario.*

We examine below the soundness of planning on the basis of a three-week LIL restoration duration. If that duration proves significantly too short, predicting seven day "heavy rotating outages" comprises a significant understatement of the potential consequences for customers following a large LIL outage in extreme conditions.

Without a transmission solution, additional resources on the Avalon Peninsula will be needed. A subsequent study, the Avalon Capacity Study, outlined below, examines such an outage in greater detail, and analyzes options that would reduce or eliminate the constraints.

C. LIL Outage Threat and Response Studies

Whether considered an N-1 or an N-2 condition, the risks and consequences of a lengthy bipole LIL outage require careful consideration, given the potential for a structural failure to take both poles out of service simultaneously. Such a failure can have very significant consequences, particularly during extreme winter weather, which can both extend outage durations and magnify outage magnitudes.

Hydro has undertaken and commissioned substantial study of LIL outages. Norway-based EFLA worked with Power Supply in providing comprehensive analyses of expected LIL outage frequency and duration. EFLA's more than 35 years of experience in transmission line design extends to more than 20 countries. That experience includes many countries that experience harsh winter conditions, among them Canada, Finland, Greenland, Iceland, Norway, and Sweden.

EFLA's analyses did not include LIL converter station equipment or the submarine cables. EFLA provided reports of seven studies in 2018, [37] assessing probabilities of a broad range of LIL equipment failure causes and types, the impact (*e.g.*, outage) risks, and preparations to respond to equipment failures, options for staging emergency materials and equipment, and the need to clear access roads during winter conditions.

EFLA's work comprehensively identified line threats, severity levels, and outage likelihoods. The work also produced an assessment of outage durations for threats by severity levels. In summary, EFLA's work produced expectations of about:

- 2.1 monopole outages per year, averaging 1.8 hours in duration
- 0.22 bipole outages per year, averaging 24 hours in duration.

The calculated outage durations, reflecting averages, do not show ranges that reflect worst- case conditions. They also did not incorporate access delays (for helicopter or ground crew response) under poor weather conditions. We observed no calculated value for the range of expected durations of "major" outages (*e.g.*, a downed structure or group of structures), but an expectation that such an event could produce an outage of about two weeks. There does exist a graphic display of the range of outage impact levels, but it does not measure outages in terms of hours or days. Instead, it uses a categorical range of 1 (least severe) to 5 (most severe).

The 40 possible conditions identified by EFLA as causing monopole or bipole outages is comprehensive. However, concerns addressed earlier in this report about the first years of LIL operation call for a time-based stratification of those conditions. Four of them in our view pose comparatively greater threats during the LIL's first years of operation:

- Design Errors - - Possible errors in tower, foundation, and anchor designs, arising from use of incorrect data and condition assumptions
- Manufacturing Errors - - Incipient defects in line and converter station equipment or materials, not discovered in initial inspections and tests
- Construction Errors - - Defects in the construction and assembly of foundations, structures, conductors, hardware, or converter station equipment not discovered through inspections already performed.

Moreover, as our quarterly monitoring reports have emphasized for some time, the GE software on which LIL operation depends has remained a source of lingering and substantial problems. Even beyond Nalcor's current estimate that the LIL will not return to operation before early 2020, it is also prudent to consider the probabilities of its causing disruptions for phase-in period following that return

D. LIL Threat and Response Mapping

EFLA presented[38] a five-level incident categorization, which the next table summarizes.

Figure 9- LIL Incident Level Classification

Level	Description	Actions Needed	Examples of Failures
1: Minor	Localized failure - limited complications	Emergency preparation and site visit	Lightning, short term internal or external clearance, outage from galloping
2: Moderate	Localized failure -slight Complications	Site visit, corrective action, limited equipment	Insulator, hardware, conductor damage, cross-arm damage, guy failure with foundation damage
3: Major	**Localized failure – moderate complications**	**Site visit, corrective action, some material & equipment**	**Tower failure**
4: Severe	**Multiple failure**	**Site visit, corrective action, material and equipment, site camp**	**Multiple tower failures, same area, or failure of tension tower**
5: Catastrophic	**Multiple failure, considerable complications**	**Site visit, corrective action, significant material/equipment, several site camps, large logistical/materials planning effort**	**Dispersed multiple tower failures, cascade failure**

The following designations capture the likelihood that a particular hazard causing an outage will occur within a 50-year period:

- Code 1 (very unlikely) - - <5 percent
- Code 2 (Unlikely) - - 5 to 15 percent
- Code 3 (Possible) - - 15 to 40 percent
- Code 4 (Likely) - - 40 to 80 percent
- Code 5 (Almost Certain) - - 80 to 100 percent.

EFLA did not have sufficient data to identify operational or cost impacts quantitatively for all 40 hazard or threat sources and severity levels. Instead, the following qualitative scale resulted. Increasing levels indicate longer outage lengths.

Figure 10 - LIL Impact Severity Classification (Relative Outage Timeframes)

1	2	3	4	5
Minimal	**Low**	**Moderate**	**High**	**Extreme**

The next table[39] summarizes the results of combining:

- The 40 hazard or threat sources identified - - the table's first two columns
- Results under the 5-class range of incident levels - - the remaining table columns
- The resulting impact severity under the 5-class range from minimal to extreme - - denoted by the color assigned to each of the table's cells
- The likelihood code under the 5-range percentage of occurrence categories - - denoted by the number in each of the table's cells.

The chart draws attention to those events having the highest (but not on a quantified basis) outage consequence (the red-shaded cells). For those, one can determine their relative likelihood (quantified as a percentage range) of occurrence. The highest outage-consequence events involve forest fires, icing, wind, and corrosive soils. All but forest fires require the initiating event to reach at least severe levels. The likelihood of all "red" cases has been set between "possible" and "almost certain;" *i.e.*, none are considered unlikely.

Figure 11- LIL Incident Threat Matrix

	Hazard	Incident level: Minor 1	Moderate 2	Major 3	Severe 4	Catastrophic 5
1	Freezing rain, with/without wind	5	3	3	2	1
2	In-cloud icing, with/without wind	5	4	3	3	1
3	Wet snow icing, with/without wind	4	3	2	2	1
4	Extreme windstorm (low pressure)	2	3	3	2	1
5	HIW wind (Tornadoes, Downburst, Hurricanes...)	2	3	3	3	1
6	Low temperature	1	1	1	1	1
7	High temperature (with high solar radiation & no wind)	1	1	1	1	1
8	Flooding (heavy rain, snow melting, ocean)	1	1	2	1	1
9	River erosion and flooding	1	1	2	1	1
10	Land-, mud-, rockslide	1	1	2	1	1
11	Erosion of foundations, sinkhole	1	1	2	1	1
12	Ground subsidence	1	1	2	1	1
13	Loss of permafrost	1	1	1	1	1
14	Frost/Ice heave	1	2	1	1	1
15	Snow avalanche	1	1	1	1	1
16	Snow creep	1	2	1	1	1
17	Extreme snow depth	3	1	1	1	1
18	Earthquake/Tsunami	1	1	1	1	1
19	Lightning	5	4	1	1	1
20	Salt pollution	5	4	1	1	1
21	Forest fire	5	5	3	3	3
22	Geomagnetically induced currents (GIC)	1	1	1	1	1
23	Volcanic Eruptions	1	1	1	1	1
24	Corrosive soil/bogs	1	3	3	3	1
	Dynamic					
25	Galloping - flashover, wear of hardware & conductor	1	4	3	2	1
26	Vibration	1	4	2	1	1
27	Ice drop	2	3	1	1	1
	Human or animal action or vegetation					
28	Vandalism or sabotage	1	3	2	2	1
29	Theft of minor to moderate quantities	1	1	1	1	1
30	Terror action	1	2	2	2	1
31	Ground vehicle impact with tower	1	3	3	2	1
32	Airborne vehicle impact with tower/conductor	2	4	2	1	1
33	Nearby man-made hazards (clearance to nearby lines)	2	2	2	1	1
34	Animal leading to outage	1	2	1	1	1
35	Vegetation growth	1	1	1	1	1
36	Stray current	1	1	2	1	1
	Design, production and construction					
37	Insufficient/unforeseen shortcoming in design	2	3	2	2	1
38	Insufficient/unforeseen shortcoming in manufacturing	2	3	2	2	1
39	Insufficient/unforeseen shortcoming in construction	1	1	2	2	1
40	Insufficient/unforeseen maintenance	1	2	2	1	1

The criticality of the LIL during the winter season makes it important to consider the months of the year when threats prove most likely to occur. The analyses available to Power Supply include a "threat-month" chart. The next table shows that chart for threats having at least a "Major" severity classification.

Figure 12 - Most Likely Months of Hazard Occurrence

Severity	Hazard	Most Likely Months
5 - Catastrophic	20 Forest fire	June - September
	39 Corrosive soil/bogs	December- March
4 - Severe	2 In-cloud icing, with/without wind	January - March
	5 HIW wind (Tornadoes, Downbursts)	? [sic]
3 -Major	1 Freezing rain, with/without wind	January - March
	3 Wet snow icing, with/without wind	December - March
	4 Extreme windstorm (low pressure)	December - March
	18 Lightning	June - September
	19 Salt pollution	October - March
	23 Galloping - flashover, wear of hardware & conductor	November - March
	24 Vibration	December- March
	26 Vandalism or sabotage	All year
	28 Terror action	All year
	29 Ground vehicle impact with tower	All year
	30 Airborne vehicle impact with tower/conductor	Summer
	34 Insufficient/unforeseen design shortcoming	December- March
	35 Insufficient/unforeseen manufacturing shortcoming	December- March
	36 Insufficient/unforeseen construction shortcoming	December- March

E. Gaining Access to the LIL for Restoration

The EFLA study did not identify the ground travel time from Soldiers Pond and from Muskrat Falls to various remote line sections. Therefore, we sought to determine expected travel times by ground vehicles to remote towers from Soldiers Pond and Muskrat Falls, where Nalcor plans to locate crews, in both good weather and when snow cover is deep.

The LIL's 1,100-kilometer length and 3,223 steel towers pose significant access issues. The rights-of-way are 60 meters wide. The line traverses large areas having limited access from primary public roads. Normally, a Power Supply crew will be expected to investigate LIL line outages via helicopter. Helicopters can also deliver crews and materials to structures to address smaller repairs. However, weather may delay an aerial investigation or repair. If weather conditions, including wind, or the size or weight of the materials required for the repair prevents using a helicopter, then crews must use the roads to travel and deliver materials to a tower location.

One can expect circumstances that will result in extended times required for responding crews to gain access by ground vehicles to many LIL structures, especially during months characterized by heavy snowfall, icing, and wind.

We performed our inspections by car and by walking the line and structures in and about 40 kilometers beyond the Avalon Peninsula and about 50 kilometers east and 50 kilometers northwest of Deer Lake. Our views indicated reasonably convenient access to the LIL line right of ways in these areas, when not snow covered. However, Hydro has reported that snowfall can be deep in the areas around Deer Lake and on the Northern Peninsula, and in Labrador, limiting quick access to and along rights-of-way.

The map we examined showed each LIL structure location, public roads, the "LIL tower road," and "connector roads" built between the public highways and the tower road. Some of these connector roads are very lengthy. In some locations, tower roads do not directly access each tower.

Numerous connector roads between public and LIL tower roads exist on the Island portion. In some cases, however, responders would have to travel past as many as 30 spans (about four kilometers) on the tower road to reach some structures. Some locations require responders to leave the tower road, and follow the right-of-way for a number of spans. We found LIL access from public roads much more limited in Labrador. The more than 1,200-structure section in Labrador features only a single connector road at each end of that section. Traveling to the middle structures involves 150 kilometers or more on the tower road, after leaving the nearest connector road.

Public-road travel distance appears to span 1,000 kilometers on the Island and 600 kilometers between Muskrat Falls and Forteau Point. In the absence of a closer Hydro (or maybe Newfound Power) crew, even good weather would appear to require 16 hours or more for a Soldiers Pond crew and equipment to travel on public roads, connector roads, and the tower road to reach a tower in the mountain region of Northern Peninsula. A similar minimum of 16 hours would also appear necessary for a Muskrat Falls crew and equipment to travel to the mountain region in eastern Labrador. For heavy snow cover, substantially more time could be required to clear roads and LIL right of way sufficiently to permit ground access, if required.

F. Worst-Case Outage Durations

A cascading structure failure scenario occurs when an initiating structure failure (under stresses affecting neighboring structures as well) causes failure of a succession of neighboring structures. The LIL employs anti-cascading structures to limit the extent of multiple, neighboring structure failures. The LIL's conservative design and robust construction make cascading unlikely, but still possible for a string of up to 20 structures, given the deployment of these anti-cascading structures on the line.

We considered the time likely to be required to install a temporary, monopole bypass for a 20-structure cascading failure scenario. Hydro has conducted a test installation of a monopole bypass of one structure. It did so at a convenient location and under good weather conditions. Those results led Hydro to estimate a duration of 10 to 12 days to bypass a single structure. Ground access required under severe winter conditions could add as much as another four days, bringing to 16 the number of days required to bypass one structure in a remote location. Simple extrapolation of this roughly two-week period would generate an outage duration that could range to perhaps six months for a worst-case cascading failure scenario on the LIL.

How much shorter that period can become will depend on personnel, equipment, and transportation availability. Certainly, Hydro will be able to marshal added resources. Those limits in any case are likely to operate as significant constraints on minimizing the duration of outages under a cascading failure scenario. In any event, months, not weeks become the measure of outage durations in such a case, unlikely though it may be.

We also found that substantial uncertainty remains about activities required and resources needed for major outage response. Completing and resourcing plans to address personnel, equipment, and transportation needs therefore should form a high priority for Hydro.

Other scenarios, such as insulator failure through damage or salt contamination have much higher likelihoods of occurrence. However, they do not pose the same duration length problem, and are much more likely to affect only a single pole. With helicopter access, it is reasonable to expect repair completion within a day or two, and perhaps somewhat more, if multiple insulator strings also require cleaning or repair.

G. LIL Restoration Exercises

Power Supply conducted four LIL restoration exercises in 2018 and it plans to continue the exercises in the future. [40]

The fourth exercise proved most informative for our purposes. It included full construction, adjacent to the LIL line on the Island of wood-pole structures required for a "half bypass." Crews erected three dead-end structures and one tangent structure, and strung conductor. The exercise did not involve making the LIL conductor connections that would be necessary to complete an actual bypass operation.

H. Inspection, Maintenance, and Critical Spares

Conducting periodic inspections of the LIL line and periodic preventive maintenance of the converter station equipment minimize unexpected equipment failures and outages resulting from them. Power Supply has developed preventive maintenance programs designed to reduce the risk of unexpected LIL equipment failures.

Maintaining appropriate spare critical equipment at suitable locations reduces outage times. Power Supply reported that it stores a spare converter power transformer and harmonic filter at each of the two converter stations. Development of a comprehensive list of required spare critical equipment remains in progress. Stores now include 10 spare tower structures. The EFLA work addresses in detail staging locations, but Hydro has not yet determined where it will stage materials (*e.g.*, wood poles for bypass structures) along the line.

Power Supply plans to station LIL operators, line crews, converter station crews, and control technicians at Muskrat Falls and at Soldiers Pond. However, it has no current plans to stage any crews along the 680-kilometer Island segment and the 386-kilometer Labrador segment. Power Supply could call on Hydro, or even Newfoundland Power, as practical, to provide first responders in areas close to their operating offices and depots. Power Supply also has two-year post completion maintenance contracts with its HVdc line and converter equipment suppliers/contractors.

Power Supply has not provided a detailed plan for how to best use its line workers, Hydro's line workers, or Newfoundland Power's line workers to be first responders at each LIL line section.

I. Conclusions - - Extended LIL Outages

21. We found Hydro's estimates of restoration times following bipole LIL outages insufficiently conservative.

Establishing a proper range of restoration times requires consideration of worst-case scenarios. Hydro needs to consider time required to identify outage causes, conduct analysis; prepare necessary crews and materials, wait for severe storms to pass, provide transport over roads under severe snow cover, and consider icing and wind conditions. Hydro has assumed the availability of helicopter travel to most LIL line events. That assumption is not consistent with worst-case weather conditions.

We have not seen evidence that Hydro has analytically studied likely durations considering remote locations and extreme weather for each restoration step. Failing such study, we would offer the following adjustments to restoration estimates that Hydro has offered.[41]

Figure 13- Possible Bipole Outage Restoration Times

Event	Hydro's Estimate	Liberty's Adjustment*
Broken Neutral/Return	8 to 24 hours	Up to 5 days
Broken conductor contacts other pole	8 to 24 hours	Up to 5 days
Up to 3 fallen towers	Up to 3 weeks	Up to 6 weeks
More than 3 fallen towers	>6 weeks	Up to several months
Busbar fault	8 to 48 hours	Up to 5 days (absent parts availability)
Loss of 3 undersea cables	6 to 18 months	NO ADJUSTMENT

*Assumes helicopter access not available

22. Gaining access to LIL outage locations can prove very difficult in adverse weather conditions, requiring more time than appears to be contemplated by Hydro's estimates of restoration durations.

Whatever the time it takes to make repairs, true measurement of restoration time needs to consider the duration required to gain line access. Access to downed structures during harsh conditions can have a substantial impact on restoration times. Helicopters can marshal equipment and personnel at downed line locations. Off-road equipment designed for use in heavy snows can employ access roads to reach such locations as well. Nevertheless, the remoteness of some locations will delay access when main roads are under deep snow cover and conditions prevent flying. Therefore, we sought to provide some quantitative measure of potential access times, based on our review, and considering that the data Hydro made available to us did not consider this factor.

Absent better information from Hydro, we believe that when helicopter access is not available, ground travel for all necessary crews, equipment, and materials to remote Island and Labrador line locations may take as much as two days in good weather. With public, connector and tower roads rights-of-way blocked by deep snow cover and possible high winds, it may take up to four days for crews, equipment, and materials to gain access by ground transportation.

23. Hydro's analyses of bipole LIL outage causes significantly understate the duration required to perform work necessary to restore single-pole, temporary operation.

We sought to provide, using the information available from the EFLA work, photographic and visual inspection of line segments and structures, Hydro's responses to our data requests, and discussions at our various work sessions and field visits a more quantified view of response times. We included estimates for converter station equipment and submarine cable outages (not addressed by the EFLA studies).

The following table shows our estimates, which include preparation time, but not travel time (addressed further below). Note that these estimates assume Hydro's description of currently planned resources. They also assume the existence of sufficient levels and locations of required material and equipment (which remain unknowns pending further analysis, decision making, and resource acquisition by Hydro). They also assume fully developed emergency preparedness and restoration procedures and training, which also remain under development at this time.

Figure 14 - Liberty-Estimated LIL Restoration Times

Outage Cause	Risk	Consequences	Restoration
Tower/Conductor Failure • Design/construction, maintenance error • Storm exceeding design • Deliberately cut guy wires • Structure bolt, steel removal • Aircraft/heavy equipment hits • Foundation, guy wire failure	• Low - Steady State • Higher - early operation	• Bipole outage • Cascading structure failure potential	• 2 - 3 weeks for single-structure by-pass, weather, location dependent • 2 - 6 months for cascading tower failure
Converter station destruction • Fire, explosion, aircraft	• Very Low	• Bipole outage	• > 6 months
Convertor station equipment failure • Power transformer, circuit breaker, harmonic filter, etc.	• Moderate, greater during early operation	• Monopole outage	• 3 - 6 weeks
Convertor station bus failure	• Moderate	• Monopole outage	• Up to 5 days, (with parts availability)
Single submarine cable failure • Cable insulation failure • Iceberg	• Low	• None if transfer equipment operates as designed, if not, manual monopole transfer	• None, or 8 - 48 hours

• Equipment dragged by ship			
Multiple subsea cable failure	• Low	• Bipole outage	• 6 - 18 months
Insulator Failure • Vandalism • Salt Contamination	• High	• Monopole outage	• 1 - 5 days, weather dependent
Conductor connecter or other hardware failure	• Moderate, greater in early operation	• Monopole outage	• 2 - 5 days, weather, location dependent
Broken Shield Wire • Lightning damage • Connector failure • Corrosion	• Moderate	• Monopole or Bi-pole outage	• 2 - 5 days, weather, location dependent
Labrador return failure • Lightning, weather damage to conductor on towers	• Moderate	• Monopole outage	• 3 - 10 days, weather, location dependent
Island return failure • Wood-pole conductor mounted at LIL Island ends • Connection to sea water electrodes	• Moderate	• Monopole outage	• 1 - 3 days

24. Hydro has not provided sufficient, quantified assessments of the probabilities of extended bipole LIL failures under extreme load conditions, employed a robust range of likely restoration durations, or quantified the full customer-service impacts of long-duration outages.

The existing analyses available to Hydro use a qualitative, five-grade rating to estimate outage-impact levels, or restoration times. Beyond that, we have a single point estimate of restoration times. Moreover, Hydro's two- or three-week estimates appear even lower (considering Hydro's test under favorable location and weather conditions) than what might be expected on average, let alone under extreme conditions. We believe that worst case overhead line restoration durations will be measured in months not weeks. The analysis that Hydro has provided is supported by expert analysis, but needs to be taken to another level.

The following probabilities need to be calculated and aggregated:

- Each of the structure failure possibilities (for example, numbers of structures, remoteness of structures, multiple failures at disparate locations) covering the range of possibilities (including cascading failures)
- The time it will take to gain access to failure locations under severe weather conditions that substantially slow ground access and foreclose helicopter access for an extended period

- The time it will take to restore temporary, single-pole operation for each of the possibilities.

The following consequences need to be identified for each duration (access plus restoration) of each failure possibility, assuming those durations correspond with load conditions under extreme weather:

- Days of the week and times of day and numbers of hours during which UFLS or other customer-service disrupting actions will be necessary
- Numbers of customers affected.

As noted elsewhere in this report, Hydro has attempted some measurements, but not for the circumstances or durations identified here.

25. Important activities required to prepare for response to LIL outages remain incomplete.

We found work to meet a wide range of outage preparation and response needs still in progress. They include:

- A final list of required materials and critical equipment does not yet exist.
- Storage and staging areas for material and equipment remain to be optimized, considering required travel times.
- Formal plans for crew response by line section when ground travel is required (considering, for example, reliance on Hydro and Newfoundland Power resources) do not yet exist.
- An interim version of a transmission emergency-restoration document exists, but is not scheduled for completion until later this year; comprehensive, resource-loaded restoration procedures will prove necessary to minimize outage durations.
- Response training also remains under development.

Hydro needs to make completion of these preparatory activities final.

Power Supply did conduct some mock LIL outage exercises in 2018. Hydro plans to continue those exercises. Such continuation is important; it should consider scenarios that address the potential for reducing response and repair times under adverse conditions and at remote locations.

Power Supply currently plans to locate line workers at Soldiers Pond and at Muskrat Falls, but the resulting ground-travel response times need to be considered in determining the optimum balance of cost minimization and ground-travel times that may be required to address outage events, particularly at remote locations.

J. Recommendations - - Extended LIL Outages

10. Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages.

Hydro, stakeholders, and the Board require such an analysis to determine the full range of service-disruption likelihoods and consequences occasioned by a bipole LIL outage. We believe that the current state of information and analysis serves to understate potential consequences. This analysis should be completed as soon as possible, in order to support consideration of the value and costs of reliability-risk mitigation measures recommended in Chapter VI of this report.

The range of events to be considered should range from single to multiple structure failures and locations and it should consider both travel and on-site work durations under extreme weather conditions. A probability of occurrence and a full range of restoration times should be calculated for each such occurrence.

11. Hydro should complete remaining steps to prepare for LIL outages as soon as possible.

With LIL's operation critical to ensuring reliability, Hydro needs to place high priority on finalizing material and equipment lists, determining storage and staging areas that optimize response times, completing plans for crew response by line section, completing the emergency restoration plan, completing comprehensive and resource-loaded restoration procedures, and providing response training.

VI. Generation Asset Reliability

A. Introduction

Our past reviews have expressed concerns about the condition of a number of Hydro's generating assets and about reliance on Hydro's forecasts of their availability. As part of this examination we reviewed recent operating performance metrics, issues found by Hydro and its efforts to address them, and a variety of maintenance records, condition assessments, root cause analyses, and other documentation providing evidence about reliance on these assets in the future.

The operation of the Holyrood Generating Station has been a major focus of our prior reliability work, and it underlies a substantial portion of reliability concerns addressed in our August 2016 Report. The three-unit nominally-rated 500 MW Holyrood station, located on the south shore at Conception Bay, employs three oil-fueled, steam cycle generating units. Built in the late 1960s (Unit 1 and 2) and in 1977 (Unit 3), the units have typically operated between loads of 80 MW and 150 MW over the years. Serving primarily as sources of supply in the winter season, design of the units also accommodates year-round operation.

We have also expressed significant concerns about reliance on two small units:

- The 50 MW Stephenville gas turbine plant, located in Stephenville
- The 50 MW Hardwoods gas turbine plant, located in the west end of St. John's.

We conducted a series of work sessions with Hydro management to address these and other generation assets, reviewing with them detailed sets of data about the units, discussing observations we have made in the past about the units, and addressing capital, operations, and maintenance expenditures and plans. This chapter describes what we found to be an improved approach to managing the generation assets and the reasons why we conclude that Hydro's assumptions about them in reliability planning are sound. We specifically addressed:

- Holyrood
- Holyrood CT
- Hardwoods CT
- Stephenville CT
- Bay d'Espoir
- Hinds Lake
- Upper Salmon
- Exploits
- Granite Canal
- Paradise River
- Cat Arm

B. History of and Plans for Holyrood and the Two Gas Turbines

Holyrood Units 1 and 2 suffered substantial tube leaks in early 2016. Hydro's analyses around that time established susceptibility to inordinate numbers of future tube failures as a material risk. Hydro decided to de-rate all three units at Holyrood to mitigate that risk.[42] Hydro then retained an expert firm to complete a more detailed assessment.[43] The report of this assessment expressed considerably more optimism about the station's boiler tubes, but our August 2016 Report nevertheless continued to express reservations about reliance on Holyrood availability for planning purposes. We examined Holyrood's condition more closely:

- To assess reliance upon it pre-Muskrat Falls operation and for short-term operation during initial LCP operation

- To examine whether merit exists in considering it as a longer-term option to address reliability issues, such as those presented by a long-duration bipole LIL outage.

Hydro has long planned to retire Holyrood (save for operation on one unit as a synchronous condenser). For reasons expressed earlier in this report, we believe that that plan requires a fundamental re-examination. The decision made to retire it long ago as part of LCP planning appears to have foreclosed such efforts. However, recent circumstances appear to have created a need to examine continued Holyrood availability as a source for addressing bipole LIL outages. Detailed analysis of that possibility is not, however, well advanced, but, as we describe elsewhere in this report, should comprise a first priority for Hydro, stakeholders, and the Board. We therefore paid particular attention to Holyrood's condition.

Hydro also plans for near-term retirement of the Hardwoods and Stephenville CTs, units about which we have held concerns as reliable sources of capacity since our December 2014 Report. Already high forced outage rates and other problems later became more acute. In early 2016, the Hardwoods and Stephenville CTs both failed within six weeks of one another, continuing a pattern of unavailability at key times approaching or during each winter since December 2013. Plagued by both a lack of availability per se, or a failure to start when called upon has made them undependable sources of capacity. Hydro historically made significant expenditures on the units. By 2016, the roughly 40-year old units had already exceeded their average useful life of 35 years. Our August 2016 Report considered it questionable then to assume a good chance of both or either unit starting when needed.

We examined and discussed with management plans and information surrounding retirement of Hardwoods, and Stephenville, old units that no longer have robust supplier support for replacing equipment.

C. Our Assessment of Holyrood's Condition

Hydro's unit Assessment Reports provided a primary source of information for our assessment. Where available, such reports generally comprise an important source of information about material condition of the assets assessed. Equipment assessment reports generally come at the request of an owner seeking an overall asset review or one of particular systems or equipment. We also reviewed all Material Condition issue causal analyses performed over the last year, to gain further insight into asset condition. Hydro generates such causal analyses in response to known equipment conditions affecting generation capability or negatively affecting safety or environmental (regulatory) compliance.

We also examined available data about the historical performance of Hydro's generation assets. We examined the last two years' quarterly versions of the Rolling 12 Month Performance of Hydro's Generating Units Report. We chose two years to provide a time frame to identify improvements, degradations, and overall performance trends over a period that would account for perhaps isolated, or corrected conditions.

We also performed an overall review of the Work Management and Asset Management processes and practices employed to maintain generation assets in good material condition, which promotes reliable operation. Asset Management broadly consists of the comprehensive management of assets. Approaching Asset Management comprehensively includes identifying asset material condition requirements for safe and reliable operations. It also includes the planning, procurement, operations and maintenance, and asset evaluation in terms of life extension or rehabilitation of the assets to achieve optimal asset value. Good Asset Management provides a holistic, "cradle-to-grave" approach maximizing asset value. Work Management also has a direct bearing on maintaining generation assets in good working condition. This process directly supports reliable asset performance on a day-to-day basis.

1. Major Systems and Equipment

a. Steam Boilers

Units 1 and 2 employ tangentially-fired natural circulation boilers supplied by leading manufacturer Combustion Engineering. Unit 3 employs a Babcock and Wilcox front wall-fired natural circulation boiler. These steam boilers have historically caused material issues affecting Holyrood reliability. Units 1 and 2 had burned high-sulfur fuel oil. This fuel caused contamination of the boiler and its components, causing frequent unit outages for boiler cleaning. Hydro switched in 2007 to lower sulfur (0.7 percent) fuel; improved operational reliability followed. Hydro's change in fuel supply vendors in 2015 introduced fuel higher in silica concentration, followed by further issues with boiler reliability.

A number of 2015 and 2016 boiler tube leaks resulted in significant unit downtime. Hydro performed further investigations of pressure parts such as, piping and boiler tubes. These investigations found issues in these pressure parts, with repairs following. Hydro plans further repairs and testing through 2020.

Issues of these types commonly affect boilers of this age. Nevertheless, our review found overall boiler condition good, considering their age. Testing in 2017 gives reason to consider the boilers good for service through at least 2021. However, we believe that it requires a more detailed boiler assessment to ensure that no other, major reliability-affecting boiler issues exist.

b. Combustion Air Systems

The Holyrood units have also experienced issues caused by forced-draft fan vibration and by air pre-heater and economizer plugging due to contamination. Hydro has resolved these issues through specific actions, or has controlled their impacts through periodic maintenance. Combustion air systems issues should not significantly impair unit reliability in the immediate term, but these systems also warrant examination to identify potential post-2021 issues.

c. Steam Turbine and Generator

Our reviews also indicated good Unit 1 and 2 steam turbine condition, again considering equipment age. The Unit 1 steam turbine suffers a manageable vibration issue that currently requires additional time to bring the unit on line. The main turbines and control valves should remain suitable for reliable operation beyond 2021. The turbine control system will require replacement for long-Holyrood operation. The electronic components of control systems degrade over time. In addition, as typical of electronic equipment, options for securing parts and expert support for this type of equipment diminish over time; *e.g.*, electronic control cards become obsolete and vendors stop supporting obsolete equipment.

The main generators for Units 1 and 2 also appear to be in good condition, following refurbishment in 2013 and 2014, respectively. These units should support reliable operation into 2021 and possibly beyond. The Unit 3 main generator has been refurbished. Its good condition will likely support reliable operation until at least through 2021. Main generator stator rewinds may be required to extend the period of reliable operation.

d. Feedwater and Condensate System

The feedwater high-pressure piping exhibits generally good condition, supportive of reliable operation through 2021. Hydro has inspected and tested the high- and low-pressure heaters since 2010. We consider the heaters supportive of reliable operation through 2021. The condensate system exhibits reasonably good condition as well. Hydro uses a regular maintenance program on pumps and motors for these systems. In addition, spare parts available for this equipment can be installed as needed. These components should not challenge future reliable operation.

e. Cooling Water Systems

The cooling water systems, consisting of pumps, values, screens, and other equipment also exhibit reasonably good operating condition. Main condenser tube condition appears good and Hydro tests them regularly. These systems should support reliable operation through 2021. Regular continued maintenance and refurbishment of this equipment can extend the reliable operations of this equipment beyond 2021.

f. Electrical and Control Systems

The electrical and control systems appear to be in reasonably good shape. Work identified in previous condition assessments has been completed and routine maintenance and refurbishment continue to keep this equipment in good condition. This equipment should prove reliable through 2021, and then beyond with modest upgrades and repairs.

g. Main Condensers and Water Boxes

These components tend to operate in a naturally corrosive environment, which requires regular monitoring for the effects of corrosion. We consider the equipment suitable for reliable operation through 2021, with service beyond this date requiring inspection and possibly work on the water-boxes

h. Main Stacks

The three stacks are all reinforced concrete structures. The 300-foot Stack Number 1 also has a steel liner, and exhibits good condition. Hydro has repaired defective concrete areas. Stack Number 2, also about 300 feet tall, shows good overall condition. The 360-foot Stack Number 3 is in good condition as well. Recent repairs have been made to sustain good operating condition. Access ladders, platforms, lighting protection, and lights show good condition at all three, with, at most, only minor repair needs evident.

i. Fuel Oil Tanks

The fuel tanks also appear to be in good condition. The tank floors on the tanks have experienced some corrosion pitting from water in the tanks at some time in the past. The subsequent metal pitting has affected metal thickness to the point of potentially requiring repairs. Further assessment of the tanks is therefore necessary; but tank structure condition is otherwise relatively good.

2. Hydro's 2011 Holyrood Condition Assessment

AMEC American Limited conducted in 2011 a detailed material condition assessment of the Holyrood Generating Station. Hydro sought the study to assess three generation scenarios and the condition of the equipment to support these scenarios in a reliable fashion:

- Generation from 2010-2015
- Standby Generation for 2015-2020
- All units operating as synchronous condensers for 2015-2019.

This "Level 1" assessment reviewed maintenance and inspections, and included independent equipment walk-downs. The work noted Holyrood Units 1, 2, and 3 ages of approximately 49, 48, and 39 years of age, respectively. The assessment noted the operation of the units historically on a seasonal basis, and not at full load for long periods of time. This form of operation produced an observation that the unit ages from an operational perspective were much younger - - 28, 27, and 24 years, respectively. The units have been well maintained and Hydro has not operated them at their design extremes. Sustained operation near design extremes can degrade components more rapidly over time.

3. Recent Holyrood Causal Analyses

Hydro undertook several causal analyses in 2018. These analyses included human performance issues, another important aspect of generation reliability. Human performance issues can play a significant role in immediate and long-term plant reliability.

Unit 2 Boiler Opacity Excursion: On October 28, 2017, Unit 2 experienced a high opacity event, with levels as high as 58-62 percent, under an opacity alarm set at about 20 percent. The cause of the event was the installation of a fuel oil mass flow meter calibrated to a different scaling factor and in different units of measurement from those of the previously installed instrument. As a result, fuel oil fed to the boiler by the fuel oil system was not completely combusted. Plant personnel did not verify the calibration of the adapter prior to installing the meter for operation.

Fire in Holyrood Unit 1 Turbine Bearing No. 2: On February 22, 2018, with Unit 1 returning to operation following maintenance on turbine control valves, a fire was reported on turbine bearing No. 2. Hydro determined the fire's cause as insulation that had absorbed lube oil and flashed as the unit was warming up. This portion of insulation, which did not have any metallic protective coating, became wet with lube oil. The wetted insulation was not observed prior to unit start-up and lube oil containment during maintenance proved inadequate.

Unit 1 Fuel Oil Spill Bunker C. On June 16, 2018, the electricians notified the Shift Supervisor of a fuel oil leak at the pressure gauge at the discharge of the primary pump on the Unit 1 fuel oil set after the pressure gauge had let go. Investigation concluded that the fuel oil gage was either loosened or not properly tightened following maintenance on the gauge.

D. The Hydro Units

Hydro employed Hatch Engineering in 2018 to perform an assessment of the condition of Penstocks 1, 2, and 3 of the Bay d'Espoir generating facility. The inspections sought to identify issues required to be addressed during penstock maintenance to bring them to a reliable material condition. Bay d'Espoir relies on four buried penstocks to feed six generating units through separate spherical valves. The 1,200 meter, carbon steel penstocks have undergone extensive inspection and refurbishment over the last several years. Several needed significant refurbishment of the longitudinal seams, due to weld metal loss as a result of general corrosion.

Penstock No. 1 experienced multiple ruptures along the longitudinal seam. Inspections identified about 950 meters of weld seams deteriorated due to corrosion. These welds required refurbishment. Subsequently, inspections of all three penstocks occurred in the summer of 2018. This inspection showed no signs of degradation of previously repaired arears. Hydro anticipates a final report for the three penstocks will be issued later in 2019.

Kleinschmidt Associates Canada, Inc., conducted an inspection of the 465-meter Upper Salmon Generating Station penstock, the first evaluation by an outside expert since mid-1980s construction. The inspection consisted of a walk-down of the exterior of the penstock and an examination of its interior. The interior examination consisted of a visual examination of the steel and welds along with a non-destructive examination of and measurements of the steel shell. The inspection concluded that the penstock has significant remaining service life, and indicated good weld and steel shell conditions.

GCM Consultants performed a 2017 assessment of the Bay d'Espoir's service water systems. The assessment covered three of the plant's water systems: turbine cooling water, generator cooling water and the plant service water. The assessment followed reports of low flow conditions on each system, a potentially major issue because these systems cool significant equipment important to generation. The assessment identified flow to the AC Units as a cause. Recommendations to correct the issue included: cleaning the pipes to increase flow, cleaning and inspecting the pipes at regular intervals, and adding a filtering unit to the system.

With respect to the generator cooling water system, cavitation damage was found which requires the replacement of pump impellers every few years. With respect to the turbine cooling water system, the investigation found insufficient flow to the turbine guide bearing and shaft seals as the issue. GCM Consulting provided a list of corrective actions to resolve the issues. Hydro has implemented many of these actions, and modified several others to resolve flow issues. This issue is now resolved.

We found that Hydro has addressed corrective actions on all previous material condition assessments of the hydro plants.

E. Asset Management

We found a reasonably effective asset management program in place. A long-term asset planning ("LTAP") organization at Hydro Group examines long-term asset performance, and recommends asset refurbishment and modifications to ensure that assets remain reliable over their lives. The LTAP group has responsibility for developing and monitoring maintenance procedures and practices, for longer term capital improvement programs for the assets, and for spare parts strategies for the operating assets. The Short-Term Planning and Scheduling ("STPS") Group, focuses on shorter-term maintenance programs, producing annual work plans for the stations, and engaging closely on annual planning of station maintenance.

We found sound operations and work execution at the plants as well. Operations personnel at the site review work orders and establish day-to-day priorities. The STPS prepares work orders for execution based upon the priorities established by Operations. A Work Execution Group physically performs maintenance, and provides feedback to LTAP to improve practices and optimize maintenance frequency.

Hydro divides planning and scheduling into two related sets of activities. The Planning set identifies work activities, and divides them into discrete work steps for use by the field forces. Planning also aligns procedures, tools, and parts to each work order for field execution. Scheduling activities set work activity dates for actual execution based upon priorities, parts availability, resource availability, and efficiency. Hydro uses a comprehensive and appropriate series of metrics to address work planning and execution performance.

Work order planning and tracking take several forms. Hydro tracks capital work against the annual and winter readiness work plans. We found that Hydro tracks work at a reasonable level of detail at the overall and asset levels. Weekly tracking provides continual assessment of progress against plans. Periodic generation summary reports supplement the data and analysis available to management.

F. Recent Unit Performance

We looked at information about recent thermal and hydro unit performance over the past two years. Hydro's most recent report addressing generating unit performance shows broad improvement over the past 12 months, providing support for the expectations about future performance used for reliability planning.[44]

Forced outage data formed a significant area of focus in our examination of historical performance data. It combines with the information gleaned from outside reviews and asset management metrics to help in assessing where the units stand in terms of continuing to serve as reliable sources of supply across Hydro's planning horizon. We examined the nature, descriptions, and lengths of outages over the past two years.

G. Conclusions - - Generation Asset Reliability

26. Hydro has improved its operating and maintenance practices positioning them well to continue operation and giving Hydro's planning assumptions about their availability a sufficiently sound basis.

We have been critical of generating plant performance and operating and maintenance practices in the past. We examined them closely in this engagement. Our review of unit conditions and Hydro's plans in this engagement found no reason to question the availability and forced outage rates assumed for planning purposes. This conclusion represents a major departure from our prior views about reliance on available supply resources.

We found Hydro's generation assets in generally good condition. We consider Holyrood overall to be in relatively good material condition. The units are well positioned to operate into 2021, with capital improvements and regular maintenance. The major issue with air flow through the Holyrood boiler appears to be resolved; it should not re-occur if proper preventative maintenance continues on this equipment. Our examination of Holyrood's Steam Turbine, Main Generator, Feedwater and Condensate System, Cooling Water Systems, Electrical and Controls Systems, Main Condenser and Water Boxes, Main Stacks, and Fuel Oil Tanks found them, although degraded overall, in a condition supportive of operation into 2021.

We consider Hydro's application of an improved asset management program and practices to its generation assets material in bringing stronger unit performance and in increasing confidence in Hydro's projections about their performance for planning purposes.

Hydro's asset management program's design addresses short- and long-term unit reliability appropriately, and Hydro uses effective metrics to assess status and respond to any gaps in execution. The Generation Summary Reports are a component of asset management at Hydro. These generation summaries provide real time data on asset performance with regard to issues, schedule, financial impacts, and Annual Work Plan Status and Performance.

With performance issues more prevalent in the past, we examined Hydro's causal analyses for more recent events. We did not find them to raise significant equipment-related issues having significant implications for the future. These analyses addressed the Holyrood Boiler Unit 2 opacity excursion, the fire in the Holyrood turbine bearing, and the Holyrood Unit 1 fuel oil spill from bunker C. All three events resulted from human performance factors, not equipment issues.

27. The Holyrood units exhibit an operating age and a set of conditions that make them options that Hydro should consider for ensuring supply reliability short-and long-term.

Hydro has not formally committed to Holyrood's future as a generating resource after LCP operation. It is, however, we understand considering it as an option during the very first years of LCP operation. The moderate use Hydro has made of the units give them an operating age that suggests a reasonable remaining life longer than their calendar age might otherwise suggest. Hydro's practices, our observation of conditions and operating and performance data, and our discussions with management all point toward successful reliance on the units through the first several years of LCP operation, should it be deemed necessary.

The condition of the Holyrood units also makes them logical candidates to consider as alternatives for ensuring reliability longer term. The base condition of the Holyrood units and the immediate-term capital and operating plans give no reason to consider the potential for extending their lives long-term impracticable economically. To the extent that locating additional generating sources on the Island is being considered, Holyrood's units should be among the alternatives considered.

Should they be retained through a short LCP operations phase-in period, it may well be that the cost required to do so will make the incremental costs of placing them in a state suitable for long term reliance attractive. Deciding on that question will, of course be a function of system risks to be mitigated, the units' ability to respond in a reliable and timely manner, and the costs of doing so. We see no reason today to foreclose consideration of Holyrood, but recognize, and therefore recommend prompt study to determine more carefully and precisely the nature and changes that may be needed to provide the units with suitable characteristics and sufficient availability and reliability. Given current consideration of the use of Holyrood generation during an LCP phase-in period, it is important that study of unit needs address both short-and long-term use now.

We consider it timely to perform another overall assessment (the last coming in 2011) to identify important material condition issues that would need addressing to keep Holyrood a viable generation asset beyond 2021.

28. The hydro plant assets also exhibit good condition, are subjected to appropriate operating and maintenance practices, supporting the operating assumptions Hydro has made about them for planning purposes.

The hydro plant assets all appear to be in relatively good condition following maintenance on the Bay d'Espoir penstocks. The assessment of the Upper Salmon Generating Station penstocks also revealed good overall penstock condition. No other major material condition assessments were found to identify other major issues.

29. Eroding market sources of support for the Hardwoods and Stephenville units offer strong justification for Hydro's plans to end reliance on them following full LCP operation.

The Hardwoods and Stephenville GTs rely on old Rolls Royce, simple-cycle engines running on fuel oil. Hydro has refurbished unit parts many times. The manufacturer no longer supports spares. We found it sound for Hydro not to rely on them into the future, given what can be expected to be increasing difficulty in finding needed equipment, the costs for doing so, and persistent operating challenges affecting their availability.

30. There remains a need for Hydro to aggressively and comprehensively address, assess, quantify, and respond to risks that threaten generating unit reliability.

Despite our opinion that improved performance supports Hydro's assumptions about availability for planning purposes, we note that performance improvement is a fairly recent phenomenon. Assuring its continuation and addressing some human performance causes of issues at some of the stations therefore bears mention.

Our review of recent issues that have had impacts on unit reliability identified the following:

1. Boiler air flow blockage and extended repair to the boiler stop valve (Holyrood)
2. Turbine hydraulic oil contamination (Holyrood)
3. Replacement of oil-soaked turbine insulation (Holyrood)
4. Boiler duct work repairs (Holyrood)
5. Control valve issues (Holyrood)
6. Penstock issues (Bay d'Espoir/Upper Salmon)
7. Failure of generator collector assembly due to excessive brush wear (Bay d'Espoir).

Issues #1 and #6, major material condition issues, have been addressed. Issues #2, 3, 4, 5, and 7 should not have been major issues. They should have been addressed during unit walk-down prior to start-up, or addressed through good maintenance practices (#3) or have been prevented by a robust preventative maintenance program (#2, 4, 5, and 7). While improvement opportunities remain, we did find progress to date and a current focus on enhancing forward-looking risk assessment encouraging and promising in promoting reliance on generating unit availability when needed.

H. Recommendations - - Generation Asset Reliability

12. Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems.

We expect that the boilers and combustion air systems will comprise the major focus of efforts to gauge extension of unit lives as supply resources short- and long-term. The assessment needs to be conducted as soon as possible, in order to make the results available for consideration in connection with review of system vulnerabilities remaining after application of Hydro's baseline planning criteria (like N-1). The results need to provide:

- Projected operational responsiveness and reliability achievable
- Estimates of resulting capital and O&M requirements and costs
- Ranges and risks for these projections and estimates
- A sound basis for comparing resulting Holyrood operational, reliability, and cost projections and estimates with those of any other alternatives identified by Hydro.

Some other supply options, like adding CTs on the Island, will have reasonably long lead times and high costs. Those lead times may affect their suitability for providing short-term relief. Their costs may look less favorable than those of Holyrood, if costs there are "sunk" as part of a short-term solution. On the other hand, they may offer responsiveness, reliability, or costs that Holyrood may not, even after significant investment. The point is that, even if there is time under most of Hydro's planning scenarios to await committing to a longer-term solution, two factors drive a holistic consideration of future needs now:

- How Holyrood's use short-term affects long-term alternatives
- Even if an option like CTs is chosen, there remains the potential that early emerging needs under several Hydro planning scenarios may compress the time available to install them.

Put another way, Hydro may have the luxury of waiting to commit, but it is less clear that the same is true of the time remaining to select from the available options.

The team engaged to perform this assessment should possess an Original Equipment Manufacturer ("OEM") level of knowledge. The assessment should make and support specific recommendations for the range of actions appropriate to ensuring effective boiler operation over a range of durations, both short and long term. The assessment team, working closely with Hydro generation management, should offer reasonably reliable estimates of required capital and ongoing annual operating and maintenance expenses. This recommended assessment will provide useful information in considering Holyrood's future. We consider time of the essence in completing the assessment, as its results may form an important element in what we envision as a near-term process through which Hydro, stakeholders, and the Board will compare the reliability risk mitigation value to be obtained by system reinforcements (whether Holyrood proves a credible alternative or not) with the costs to produce such mitigation.

To be specific, the assessment's outputs should include:

- The work needed to be completed to improve the reliability of Holyrood through and beyond 2021
- Specific recommendations for plant life extension for all important components
- A schedule of work to be accomplished broken down by priority
- Cost to bring components to the condition to operate reliably for an LCP phase-in period and indefinitely
- Cost flow and schedule details to be broken down by equipment priority and dates.

The assessment should specifically consider the physical and procedural Holyrood changes needed to reduce startup times. Similar plants have faster start-up capabilities, but we recognize that what is feasible here requires study. Examining the cost to reduce startup times to 24 hours and to 48 hours may prove significant in assessing means to address system upsets, such as a long-term bipole LIL outage.

13. Enhance several elements of the process of managing generation assets.

Our review of the generation assets demonstrated significant improvement and confidence in relying on Hydro's projections of availability for reliability planning purposes. We did observe a number of areas that would support continuing improvement in managing the supply resources.

First, Hydro should review its preventative maintenance programs and checklists, to ensure that the correct maintenance is being done to prevent reliability issues. Several outages within the last year should have been prevented by a robust program.

Second, we recommend expansion of the work management process indicators used to track the backlog of unworked work items. We propose the addition of tracking of work-order age and priority of work orders in backlog for each asset. This indicator differs from how management tracks backlogs at present. The backlog of open work orders should then be periodically reviewed to ensure that equipment reliability is not challenged.

Third, we recommend a separate outage report tracking the status of each outage. This report should define the scope of each maintenance outage and set and track specific metrics critical to success of the outage involved. These metrics should include percent complete of defined scope of work, safety performance, and financial performance, among others. This stand-alone report would provide a good focus for accomplishing work during a maintenance outage to improve plant performance.

Fourth, we recommend a critical examination of operations and maintenance human performance. Three 2018 events addressed by Hydro's causal analyses in 2018 arose from human performance factors, demonstrating how human performance can reduce reliability.

Appendix A: Summary of Conclusions and Recommendations

Chapter Two: Study Methods, Assumptions, Criteria

Conclusions

1. **Hydro's forecasts provide a sound basis for framing the needed continuation of discussions about future supply resource needs, but those discussions need to accommodate information, analysis, and stakeholder engagement that will become available in the next coming months.**

2. **Continuing to reflect both P50 and P90 weather conditions is important in assessing future system reliability.**

3. **Hydro's application of an LOLE≤0.1 criterion is both fairly common in the industry and appropriate, in establishing a baseline for addressing system vulnerabilities, but not in ruling out others.**

4. **As Hydro has noted, consideration of sustained bipole LIL outages calls into question whether other non-N-1 conditions bear scrutiny.**

5. **Hydro's planning has not been sufficiently informed by quantitative analysis of extended LIL outage probability and duration range or by consideration of generation options to address the concerns recently raised by the TGS report.**

6. **There is a critical need for stakeholders to value reliability risks after the application of mitigation measures available to reduce them, and then to measure that value against the costs of mitigation efforts.**

7. **Hydro has established a suitably broad range of scenarios for reliability analysis.**

8. **Hydro modeled future system reliability using an industry-standard tool across a range of load forecasts, using soundly based expectations about unit performance and hydrological conditions.**

9. **Hydro has not correctly addressed the relationship between planning and operating reserve margins.**

10. **Hydro's change from a criterion of LOLH ≤ 2.8 to LOLE ≤ 0.1. produces a larger level of required reserves, and a corresponding increase in reliability.**

11. **Hydro used a common approach for developing its reserve margin.**

12. **We found Hydro's operational reserve requirement of 296.5 MW, based on Muskrat Falls units as the largest contingencies, sound on a province-wide basis, subject to concerns about the consequences of a bipole LIL outage.**

13. **Hydro has correctly concluded that lower hydro forced outage rates support lower reserve margins.**

14. **The ultimate question with respect to supply adequacy becomes more a question of affordability than of parsing planning assumptions requirements or comparability of reserve margins.**

Recommendations

1. **Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances, and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk.**

2. **Hydro should promptly commence a stakeholder engagement process to address VOLL, informed by a sound, contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk.**

3. **Hydro should continue to reflect both P50 and P90 weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months.**

4. **Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error.**

5. **Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin.**

Chapter Three: Long-Term Reliability

Conclusions

15. **Hydro has yet to examine sufficiently the option of reversing its long-standing decision to end electricity generation at the Holyrood steam units.**

16. **The consideration of alternatives should be informed by the latest information affecting demand forecasts.**

Recommendations

6. **Hydro should establish a plan and schedule for integrating the results of the current examination and subsequent processes for considering factors affecting future electrical requirements and non-generation means for influencing load and usage into a re-analysis of its future needs under a robust range of circumstances and scenarios.**

7. **Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply resource.**

Chapter Four: Near-Term Reliability

Conclusions

17. **Hydro's analysis establishes that pre-Muskrat Falls vulnerabilities remain very substantial, as they have now for some time.**

18. **Before the latest information about LIL schedule, we concluded that Hydro's contingency plan will produce marginal reliability benefits for the short-term, but has much less significance to reliability than does LIL and Holyrood performance.**

19. **The latest LIL schedule information compels a detailed assessment of the impacts of LIL absence on reliability for the coming winter.**

20. **The impacts of Holyrood and the LIL on reliability, as shown in Hydro's short-term scenario analyses raise important considerations for longer term planning.**

Recommendations

8. **Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter.**

9. **Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now.**

Chapter Five: Extended LIL Outages

Conclusions

21. **We found Hydro's estimates of restoration times following bipole LIL outages insufficiently conservative.**

22. **Gaining access to LIL outage locations can prove very difficult in adverse weather conditions, requiring more time than appears to be contemplated by Hydro's estimates of restoration durations.**

23. **Hydro's analyses of bipole LIL outage causes significantly understate the duration required to perform work necessary to restore single-pole, temporary operation.**

24. **Hydro has not provided sufficient, quantified assessments of the probabilities of extended bipole LIL failures under extreme load conditions, employed a robust range of likely restoration durations, or quantified the full customer-service impacts of long-duration outages.**

25. **Important activities required to prepare for response to LIL outages remain incomplete.**

Recommendations

10. **Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages.**

11. **Hydro should complete remaining steps to prepare for LIL outages as soon as possible.**

Chapter Six: Generation Asset Reliability

Conclusions

26. **Hydro has improved its operating and maintenance practices positioning them well to continue operation and giving Hydro's planning assumptions about their availability a sufficiently sound basis.**

27. **The Holyrood units exhibit an operating age and a set of conditions that make them options that Hydro should consider for ensuring supply reliability short-and long-term.**

28. **The hydro plant assets also exhibit good condition, are subjected to appropriate operating and maintenance practices, supporting the operating assumptions Hydro has made about them for planning purposes.**

29. **Eroding market sources of support for the Hardwoods and Stephenville units offer strong justification for Hydro's plans to end reliance on them following full LCP operation.**

30. **There remains a need for Hydro to aggressively and comprehensively address, assess, quantify, and respond to risks that threaten generating unit reliability.**

Recommendations

12. **Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems.**

13. **Enhance several elements of the process of managing generation assets.**

End Notes

[1] Vol. I page 7, Figure 2 of the RRA report
[2]https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf#search=probabilistic%20assessment
[3] Vol. I, att. 2.
[4] https://www.nerc.com/files/ivgtf1-2.pdf
[5] Vol. I, p. 8)
[6] Vol. I, p. 20
[7] "Energy Supply Risk Assessment," May 2016, Page 7
[8] PUB-NLH-299, Island Interconnected System Supply Issues and Power Outages, and GRK-NLH-033
[9] Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls Final Report, August 19, 2016, at page 43.
[10] PUB-NLH-071
[11] TP-TN-068 Application of Emergency Transmission Planning Criteria for a Labrador Island Link Bipole Outage; July 30, 2019 (filed with the Board July 31, 2019)
[12] Vol. I, p. 41
[13] Vol. III, section 2
[14] PUB-NLH-074
[15] Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls Final Report, August 19, 2016, at page 10.
[16] Final Report -- Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment, February 27, 2017at page 23.
[17] Public Utilities Board Muskrat Falls Review, Exhibit 106, page 32 of 34.
[18] Nalcor's Final Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, March 2, 2012, Page 44 of 55, lines 16 to 21.
[19] Vol. I, pp. 40-41
[20] Vol. III, p. 21
[21] Table 2 (from Vol. III, page 65, Table 16)
[22] Vol. III, p. 64
[23] Vol. III, p. 4
[24] Vol. III, p. 66
[25] Vol. III, p. 67
[26] Vol. III, p. 68
[27] From Annual LOLH, EUE, and Normalized EUE Results, from Vol. II, page 19, as Table 2
[28] Labrador-Island Link In-Service Update of March 4, 2019, p. 9,
[29] March 27, 2019 Work Session with Hydro.
[30] TTO Progress Report Q2 2019, July 30, 2019, slides 6 and 22
[31] Hydro's May 15, 2019 Near-Term Generation Adequacy Report filed with the Board
[32] May 15, 2019 Near-Term Generation Adequacy Report at page 18
[33] May 15, 2019 Near-Term Generation Adequacy Report Pages 21 and 22
[34] See, for example, PUB-NLH-054, Attachment 3, page 38 of 85.
[35] Vol. III, p. 62
[36] Vol. III, p. 60
[37] PUB-NLH-054 - Attachments 1 though 7
[38] PUB-NLH-054 – Attachment Reliability and Resource Study.
[39] PUB-NLH-54 – Attachment 3
[40] Nalcor's LITL ERP 2018 Exercises Assessment, dated 2018-10-29.
[41] PUB-NLH-066

[42] "Units 1 and 2 Boilers Lower Reheater Tube Replacement and Reliability Improvements", March 2016, Page 8, Line 15
[43] Amec Foster Wheeler August 8, 2016 letter to Nalcor "Re: Holyrood TGS Boiler Tube Thinning Assessment"
[44] Quarterly Report on Performance of Generating Units for the Quarter Ended June 30, 2019, provided to the Board under date of 31, 2019