Office of the Consumer Advocate

July 17, 2026

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

Attention: Mike McNiven, Board Secretary

Dear Mr. McNiven:

Re: Newfoundland and Labrador Hydro - Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine - Avalon Combustion Turbine Project – Consumer Advocate Comments

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The Consumer Advocate thanks the Board for the opportunity to provide submissions on this substantial and consequential Build Application. In the Consumer Advocate's view, the disposition of this Application turns on three main questions:

(1) Are capacity additions needed on the Island Interconnected System ("IIS")?;
(2) Should the Avalon Combustion Turbine ("Avalon CT") be the first choice of capacity additions?; and
(3) Is the cost of the Avalon CT reasonable?

Our submissions begin with the background to the Application (Section 1) and the Board's jurisdiction (Section 2). Section 3 addresses the first question, looking at the need to retire the Holyrood Thermal Generating Station ("Holyrood TGS"), the reliability issues of the Labrador Island Link ("LIL"), and the analysis of Hydro's planning criteria and capacity reserve margins under various scenarios. Section 4 addresses the second question, considering the expansion plan analysis and expert evidence, the value of locating capacity additions on the Avalon Peninsula, and the alternative of Bay d'Espoir Unit 8. Section 5 addresses the third question, reviewing the Project's total cost and its impact on ratepayers, Hydro's proposed Management Reserve, and the potential implications of AI and data centre load on market prices. The submissions then set out certain unresolved concerns and remaining questions from the Application materials (Section 6). Finally, the submissions weigh the alternative of deferring a decision (Section 7), and close with the Consumer Advocate's conclusion and recommendations (Section 8).

1. Background

On March 21, 2025 Newfoundland and Labrador Hydro ("Hydro") submitted to the Public Utilities Board (the "Board") an Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine (the "2025 Build Application"). On April 16, 2026, Hydro filed a 2025 Build Application-Revision 1 together with "Avalon Combustion Turbine Evidentiary Update". The Application-Revision 1 (para. 22) requests that the Board approve:

(i) the requested authorized budget for Bay d'Espoir Unit 8 ("BDE8") in the amount of $1.08 billion; and
(ii) the requested authorized budget for the Avalon Combustion Turbine ("Avalon CT") in the amount of $995.9 million (originally $891 million in the March 21, 2025 application).

The 2025 Build Application-Revision 1 (para. 14) indicates that the expected completion date for the Avalon CT is early 2030 (originally late 2029 in the March 21, 2025 application). The 2025 Build Application followed a long process that included an analysis within the Reliability and Resource Adequacy Study Review proceeding during which Hydro determined that a "*minimum investment is necessary to ensure Hydro can continue to provide service that is safe and adequate, and just and reasonable, as required by Section 37 of the Act.*" and

> *The 2024 Resource Adequacy Plan assessed the integration of new assets, system reliability and the effects of electrification and decarbonization across various scenarios. The analysis highlighted that, in all modelled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers"* (para. 2 and 3, respectively, of the 2025 Build Application-Revision 1).

The procedural history of the 2025 Build Application is as follows:

1) Early in the process, the Board enlisted the services of Bates White Economic Consulting, LLC, which had been previously engaged by the Board to advise on the 2024 Resource Adequacy Plan ("RAP") and the Reliability and Resource Adequacy Study ("RRAS") Review, to undertake an analysis of the 2025 Build Application and provide advice to the Board.[1]

2) On March 12, 2025, Hydro submitted its Application for Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine.[2] In P.U. 17(2025) the Board approved the requested amounts of $30,710,000 for the Avalon CT and $16,670,000 for BDE8. The Consumer Advocate had opposed that application.

[1] Letter of May 7, 2025 from the Board to the Parties.
http://pub.nl.ca/applications/NLH2025AvalonCombustionMarch/schedule/To%20Parties%20-%20Process%20-%202025-05-07.PDF

[2] This was a refile of the application originally submitted to the Board on February 27, 2025 but which the Board did not accept as filed because "*the evidence is inadequate to allow an efficient and effective review*"; letter from the Board to Hydro dated March 7, 2025.

3) On December 12, 2025 Hydro filed its Application for Additional Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine. In P.U. 7(2026), reflecting a Settlement Agreement among the parties including the Consumer Advocate, the Board approved the request for funding of an additional $29,294,000 for the Avalon CT.[3]

4) On April 16, 2026, Hydro filed its revision to the 2025 Build Application along with the Avalon Combustion Turbine Evidentiary Update.

5) On May 13, 2026, the Board issued a review schedule specifically for the Avalon CT and which provided for RFIs from the parties by June 19, 2026 and responses from Hydro by July 3, 2026.

6) On June 19, 2026, Hydro filed its Application for Phase II Additional Early Execution Capital Work for the Avalon Combustion Turbine, which requested additional funding for the Avalon CT in the amount of $35,407,000. That application is currently under review by the Board.

In its review schedule for the Avalon CT issued on May 13, 2026, the Board requested comments from the parties by July 15, 2026; subsequently changed to July 17, 2026.

2. Jurisdiction

The *Electric Power Control Act, 1994* and the *Public Utilities Act* specify responsibilities respecting planning of future power supply in the province. The Application related to that legislation raises a number of points:

- Hydro stated in RFI CA-NLH-034a:

> *Newfoundland and Labrador Hydro ("Hydro") has an obligation to supply electrical energy to customers, as set out in the Public Utilities Act. As electricity demand grows, Hydro must construct and contract new sources of electricity generation to ensure an adequate supply for the provincial electricity grid. As a regulated utility, Hydro is under the oversight of the Board of Commissioners of Public Utilities ("Board"), which reviews and determines whether the electricity rates and capital expenditures proposed by Hydro are prudent.*

- According to the *Electric Power Control Act, 1994* (Chapter E-5.1 - *An Act to Regulate the Electrical Power Resources of Newfoundland and Labrador*, para. 6):

[3] Subsequently, in P.U. 21(2026) the Board approved Hydro's request for $5,630,000 in additional early expenditures for BDE8; the Consumer Advocate had opposed that request.

Planning of future power supply

6. (1) The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.
(2) The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe.
(3) For the purpose of this section, the public utilities board may adopt those rules and procedures that it considers necessary or advisable to give effect to the subsection.

- The *Electrical Power Control Act, 1994* contains the provincial power policy (Section 3) which requires that power be delivered to customers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

In addition to the legislative provisions, the Provisional Capital Budget Application Guidelines issued by the Board state:

a) (page 2 of 18) "*Cost, performance and risk are among the factors considered by the Board in determining whether capital expenditures are appropriate and necessary to ensure the delivery of power to customers at the lowest possible cost consistent with reliable service*"; and

b) (page 2 of 18) "*The application must demonstrate that the proposals are reasonable and necessary for the provision of service at the lowest possible cost consistent with reliable service*."

Therefore, while Hydro *"must construct and contract new sources of electricity generation to ensure an adequate supply for the provincial electricity grid*", the Board has the authority to determine if the capital expenditures proposed by Hydro are prudent. More specifically, Hydro is required to prove that the facilities and capital expenditures proposed in the 2025 Build Application are needed, are just and reasonable, and are reasonably safe and adequate in the provision of power to customers at the lowest possible cost consistent with reliable service and in an environmentally responsible manner. This submission is in accordance with these legislative and regulatory provisions.

3. Are Capacity Additions Needed on the IIS?

3.1 The Need to Retire Holyrood Thermal Generating Station

Holyrood Thermal Generating Station ("Holyrood TGS") has been a critical supply component of the IIS since the 1970's. The plant is a 490 MW facility consisting of three generating units; two with capacities of 170MW and one with a capacity of 150 MW. Over the years, it has provided firm capacity and energy, albeit at high cost, and provided critical supply during significant reliability events (such as high winds, freezing rain, and the frazil ice event this year at Bay d'Espoir) and during years with low precipitation that limited production from its hydro generation plants. Holyrood TGS is also strategically located on the Avalon Peninsula where more than 50% of the IIS demand is located. Over the years, the transmission system has developed to support Holyrood TGS owing to its significance as a supply resource to the IIS.

What is clear is that Holyrood TGS is a 56-year old, aging, expensive, and inflexible oil-fired plant. Its reliability problems are longstanding and were highlighted by its failure during the DarkNL outages of January 2014. Retirement of the plant has been under discussion since at least the Province's 2007 energy plan, *Focusing Our Energy* (although the emphasis at that time was environmental rather than reliability-driven).

3.1.1 Holyrood TGS Costs

From 2021 to 2025, Holyrood TGS costs averaged $187 million annually (CA-NLH-003, Table 1). Going forward (2026 to 2029) [4], Holyrood TGS costs are forecast to average $127 million annually (CA-NLH-003, Table 2). If Holyrood TGS operations are extended through 2035, costs in the 2030 through 2035 period are forecast to average $138 million annually (CA-NLH-003, Table 5). It is clear that maintaining Holyrood TGS is costly for ratepayers.

3.1.2 Holyrood TGS Reliability

As noted by Hydro (CA-NLH-003b), the age of Holyrood TGS "*introduces a heightened risk of failure and increased costs associated with maintaining its operation.*" The derated adjusted forced outage rate ("DAFOR") over the past 5 years for the Holyrood TGS has averaged almost 30%, reaching a high of 43% in 2024 (CA-NLH-003, Table 3).[5] Hydro states in CA-NLH-003 (page 3 of 7) that, "*for the past three winters, a unit at the Holyrood TGS has been unavailable for all or a portion of the winter season due to forced extensions to planned outages as a result of found work or complications from repairs.*"

The evidence is clear that Holyrood TGS will become more unreliable with age. A simplified way of looking at Holyrood reliability is to assume that its availability can be estimated as 490 MW * (1 – Derated Adjusted Utilization Forced Outage Probability ("DAUFOP")). If a 20% DAUFOP is assumed, Holyrood available capacity could be roughly estimated to be 392 MW. If a 34% DAUFOP is assumed, available capacity could be roughly estimated to be 323 MW. Therefore, at a DAUFOP of 34%, Hydro can expect one Holyrood TGS unit to be out of service at all times. This appears to be consistent with Hydro's view expressed in CA-NLH-003. While it is not clear how much worse Holyrood TGS reliability can get before the high costs of keeping it in operation can

[4] The year 2030 costs are excluded because Holyrood TGS is forecast to be retired in 2030.
[5] For planning purposes, Hydro has assumed a Holyrood TGS DAFOR of 20% in spite of significantly poorer performance in recent years.

no longer be justified, it is accepted that reliability risk of continued reliance on the Holyrood TGS is growing. It may only be a matter of time before one of its aging parts further deteriorates, which could bring the closure of the plant or an exorbitant bill.

3.1.3 Holyrood TGS Environmental Considerations

Because the projected annual cost of keeping Holyrood TGS in service is small relative to the cost of the proposed build projects, it is tempting to treat continued reliance on Holyrood as the prudent, lower-cost path. That course is not open to Hydro for long. Holyrood is constrained by the federal Clean Electricity Regulations (SOR/2024-263) under the Canadian Environmental Protection Act, which take effect January 1, 2035; from that date the CER's emissions limits are expected to force Holyrood's retirement. Hydro must therefore plan now for that retirement rather than defer it. Hydro has acknowledged that it intends to retire Holyrood TGS earlier than 2035, with the approval of its proposed builds (CA-NLH-003, page 5 of 7): "*While the Holyrood TGS is constrained by federal Clean Electricity Regulations which preclude its operation beyond 2035, Hydro's position is that the Holyrood TGS should be retired earlier than 2035.*"

The forced outage rate on the Holyrood TGS plant is high and, it appears, it is increasing. The units require long, annual maintenance and capital investment to stay open. The fuel is heavily polluting and its price can swing wildly, as it is exposed to rising fuel costs. On top of this, the units are designed to be baseload generators, not to ramp up and down as needed, and they take days to start from cold, which makes them very poor backup generators, which is one of their main functions in the current Hydro system. Even if Holyrood TGS could be extended further, in the long run, it will be economically beneficial to replace its firm energy requirement with wind and its capacity with flexible peaking units.

3.2 The Muskrat Falls Project

The Muskrat Falls Project ("MFP") provides important context behind the present Hydro build applications. The MFP comprises the 824 MW Muskrat Falls generating station ("MF") on the lower Churchill River in Labrador, the Labrador Transmission Assets and the Labrador-Island Link ("LIL"), an 1,100 km high-voltage direct current transmission line that delivers MF power to the Island grid at Soldiers Pond. The project was sanctioned in December 2012 with an estimated cost of $7.4 billion. It delivered first power in 2020 and was declared fully commissioned in April 2023, at a final cost of approximately $13.5 billion. Ratepayers were promised that this investment would secure a reliable supply of clean energy for the Island. The extent to which the MFP has delivered on that promise - and can be counted on going forward - lays the groundwork for Hydro's current build proposals, including the Avalon CT.

3.2.1 The Underperformance of the MFP

One of the principal objectives and promised benefits of the MFP was the retirement of the Holyrood TGS. Holyrood TGS has provided reliability benefits to the IIS in three distinct but connected ways: (1) firm capacity; (2) firm energy; and (3) capacity located on the Avalon Peninsula, where more than half of IIS demand is concentrated. The MFP was intended to address all three of these functions with the goal to retire and replace Holyrood TGS.

The MFP, however, has failed to fully cover any of the three functions of Holyrood TGS, and the plant has remained in service, despite its deteriorating condition. This has led Hydro to propose three additional assets: the Avalon CT, BDE8, and several hundred megawatts of wind generation. These expenditures that are now before the Board represent costs that ratepayers must bear to account for the underperformance of the MFP.

3.2.2 Firm Capacity and the Reliability of the LIL

Hydro's own forced outage rate assumptions reveal a reliability concern for the LIL - and that concern is one of the principal drivers of the need for the additional capacity sought in this Application.

In generation adequacy, the concept of firm capacity is being replaced by perfect capacity and effective load carrying capability ("ELCC"), but firm capacity, as used by Hydro, is still used by many utilities today. In their modelling, Hydro has given the LIL a capacity of 700 MW and notes that increasing to the LIL's stated capacity of 900 MW is not required because the driver of the LIL's contribution to reliability on a peaking basis is the assumed bipole equivalent forced outage rate ("EqFOR") range of 1% to 5%.[6]

As Hydro states, the 1% EqFOR is roughly equivalent to 4 days a year, on average. An International Council on Large Electric Systems ("CIGRE") survey reports 3.2% in their similar metric forced energy unavailability (FEU) for HVDC lines from 1983-2016. There is an important distinction between these two metrics. CIGRE's 3.2% includes both monopole and bipole outages, while the LIL EqFOR is only on bipole outages. On traditional HVDC lines, bipole outages require both poles to fail or for a converter station at either end of the line to fail. Bipole outages are much more significant as the entire HVDC corridor is lost, instead of derated. These are more rare and traditionally shorter than monopole outages. PUB-NLH-212 cites bipole outages with frequencies ranging from 0-0.4 outages per year with durations up to, on average, 2.27 hours. Hydro's current assumption is that the entire LIL will fail, on average, for 88 hours a year.

The LIL Shortfall assumes a 6-week outage, or just over 10% of the year. In a probabilistic sense, the 1% bipole EqFOR is similar to, but not the same as, assuming the LIL Shortfall happens once every 10 years. That would not be considered a reliable transmission line in other jurisdictions.

[6] Hydro recognized in its Reliability and Resource Adequacy Study – 2022 Update, Volume I: Study Methodology and Planning Criteria, page 16 that "*the previously-anticipated bipole forced outage rate of 0.0114% is no longer appropriate.*"

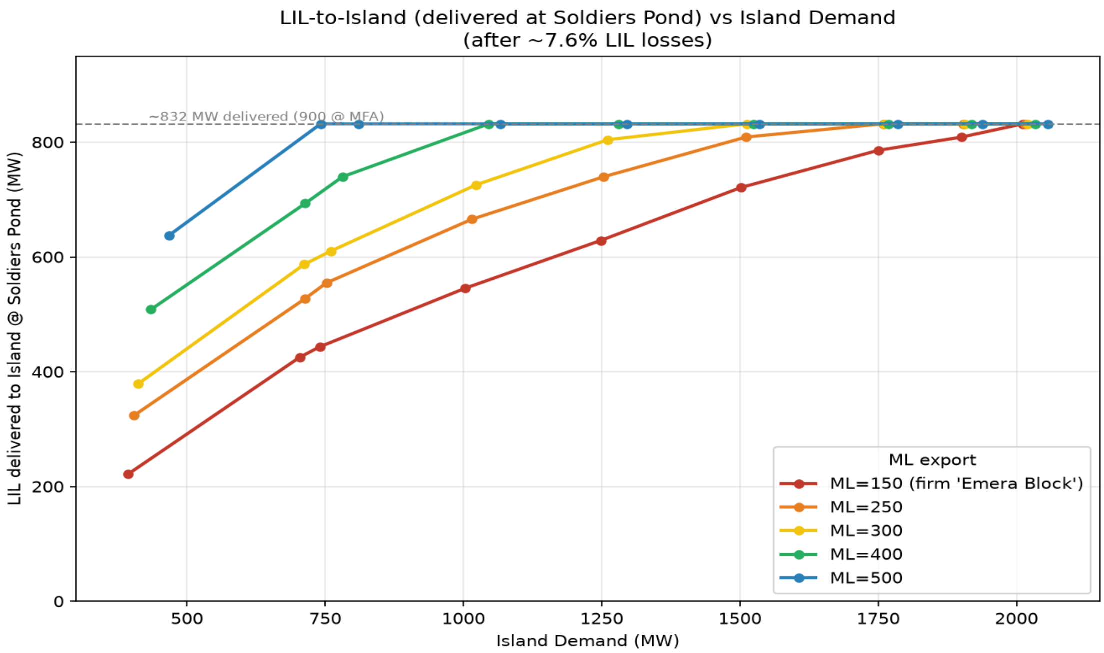
The Consumer Advocate is not in a position to challenge the 1% bipole EqFOR assumption used by Hydro, but Hydro's choice of that baseline indicates that Hydro lacks confidence in the LIL's reliability; that it expects the LIL to perform far worse than comparable bipole HVDC lines; and that it does not regard the LIL as capable, on its own, of providing the capacity needed to retire Holyrood TGS.

3.2.3 Firm Energy and the Underfrequency Load Shedding Scheme

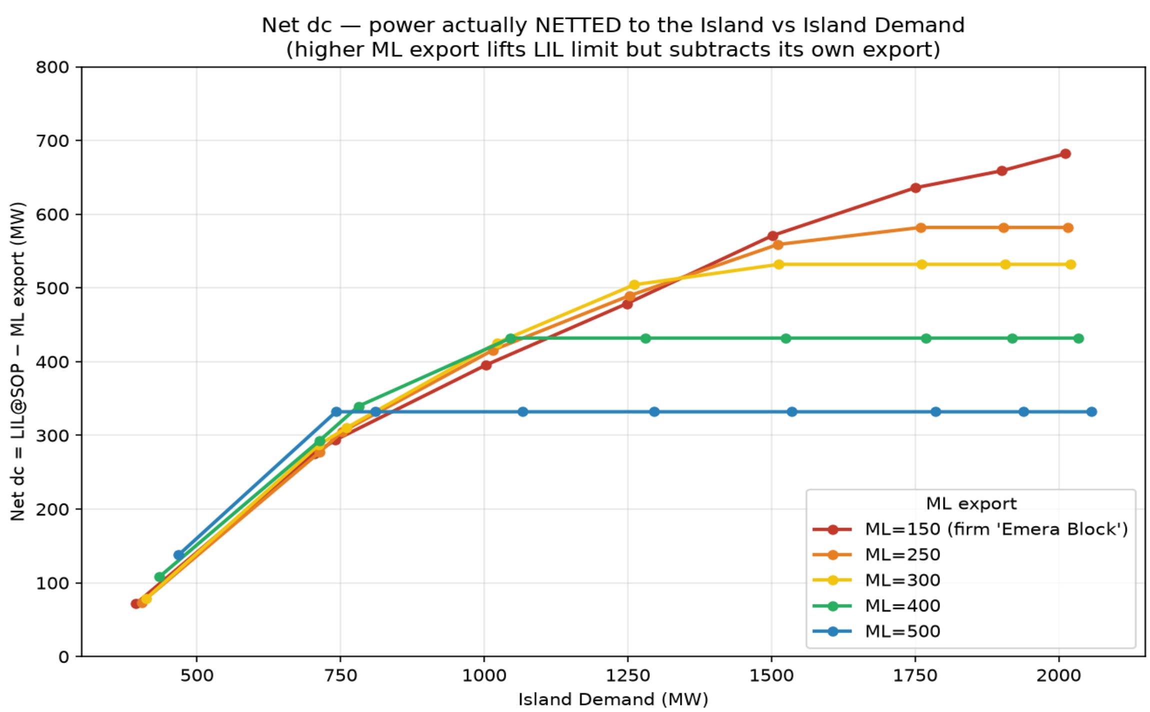
The hydro reservoirs on the Island are not sufficient to meet the annual demand of Hydro's customers on their own. Holyrood TGS has been the traditional backstop, picking up generation when the reservoirs on the Island get too low.

The Muskrat Falls plant has, on average, 5.1 TWh of energy with firm energy of 4 TWh. 1 TWh is committed as part of the Nova Scotia Block, but the remaining ~3 TWh should be available for Island native load as the Energy Access Agreement is non-firm in nature and Hydro can utilize it if required in a low hydro sequence. The MF inflows, driven largely by the generation patterns of Churchill Falls and precipitation of Labrador, are not expected to be correlated with the inflow sequences of the Island reservoirs. These factors indicate Muskrat Falls should have ample firm energy to meet the requirements of Hydro customers. But, in the 2024 RRA, Hydro identified a substantial firm energy requirement deficit, after the MFP's commissioning and Holyrood TGS' retirement.

The MFP cannot fill that void because of the LIL's Underfrequency Load Shedding Scheme ("UFLS"), which defines the relationship between LIL Flows, Island Demand, and Maritime Link ("ML") Flows. The higher the Island Demand, the more net LIL flows can be brought to the Island. For example, the chart below shows that, if Island demand is 1500 MW - a cold winter's day - then around 700 MW can be brought to the Island while a minimum of 150 MW must be sent across the ML, netting approximately 550 MW to the Island. In the winter, this limits the ability of the LIL to ramp up to meet Island loads, but it also hampers the ability of the LIL to deliver power to the system across the year and to help meet the firm energy requirements of Hydro customers.



On a mild day, with an Island Demand of 1000 MW, if Hydro sends 150 MW across the ML, then the LIL can flow around 550 MW, so the LIL can satisfy about 400 MW of the Island Demand requiring generation on the Island to meet the remaining 600 MW of its Demand. Another way of visualizing this relationship is to calculate the net power to the Island as a function of Island demand, as shown in the figure below.



This arrangement is very restrictive for Hydro and beyond the clear implications for bringing firm energy to the Island, it will also limit Hydro's ability to optimize exports for sale and the interaction between the Island's Hydro fleet and any non-dispatchable renewables Hydro adds to the system. The MF plant has a limited reservoir and is beholden to the outflows of the Churchill Falls plant upstream, which will further restrict Hydro's ability to optimize its resources.

This is relevant to the 2025 Build Application because the Avalon CT will not provide significant firm energy to the system, so adding firm capacity to the system alone will not be enough to retire Holyrood TGS.

In short, the story that frames this Application is one of promised reliability that has not materialized. The MFP was sanctioned on the promise that it would allow Hydro to retire Holyrood TGS. Because of the LIL's unreliability and the restrictions of the UFLS, it cannot - at least not without further investment. The need for that investment must be assessed on the system as it exists, and the Consumer Advocate does so in the sections that follow. The Board should weigh Hydro's requests with this context squarely in view: the Avalon CT and the other expansion options under consideration represent, in substantial part, costs ratepayers must pay to account for the deficiencies of the MFP.

3.4 Meeting Hydro's Planning Criteria

3.4.1 The Planning Criteria

The key challenges for Hydro are dealing with the loss of capacity from the retirements of its thermal assets, primarily the Holyrood TGS (490 MW), Hardwoods GT (50 MW) and Stephenville GT (50MW). To evaluate the need for expansion of supply on the IIS, Hydro employs three resource planning criteria in its determination: the Energy criterion, the Probabilistic Capacity criterion and the LIL Shortfall criterion[7].

Energy: Both the Island and Labrador Interconnected Systems should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

An energy criterion is in common use in Canada and the United States, and is relatively straightforward. The Consumer Advocate notes that the 2025 Build Application has very little impact on energy requirements as the Avalon CT will be operated as a peaking plant, providing energy only as necessary to provide capacity when needed during emergency situations on the IIS. BDE8 provides no net increase in energy as it does not result in any additional water being sent through the turbines at the Bay d'Espoir hydro system.

Probabilistic Capacity: The IIS should have sufficient generating capacity to satisfy a loss of load hours (LOLH) expectation target of not more than 2.8 hours per year.

[7] See Hydro's response to "Follow-up Questions for NL Hydro - Relating to Cost of Service Methodology".

A loss of load probabilistic capacity criterion is in common use in Canada and the United States, although the target LOLH may vary among jurisdictions. Hydro has chosen an LOLH of 2.8 hours, indicating that it translates to a Loss of Load Expectation (LOLE) of 0.2, or an expectation that the load will not be supplied in 2 days of a 10-year period. An LOLE of 0.1, a loss of load expectation of 1 day in 10 years, is in common use in the United States. Hydro believes that a LOLE of 0.2, as opposed to 0.1, better reflects the views of customers that lower cost is preferable to higher levels of reliability. The Consumer Advocate acknowledges Hydro's adjustment to the reliability criterion from 0.1 LOLE to 2.8 LOLH, which demonstrates a commitment to finding a balance between generation reliability and cost. The 2.8 LOLH represents a reliability standard that is less reliable than any other significant jurisdiction in North America.

Probabilistic criteria are often translated into a target capacity reserve margin to make reliability criteria more easily understood and enable rough comparisons between utilities and jurisdictions. A typical target capacity reserve margin is 15%, but the margin is dependent on a number of factors, necessitating the need for probability calculations. For example, systems with large amounts of hydro generation may have lower target capacity reserve margins because hydro generation tends to be more reliable than thermal generation. Further, smaller systems may have higher target capacity reserve margins. For example, Nova Scotia Power plans its system to meet a target 20% capacity reserve margin (Nova Scotia Power 2024 10-year System Outlook (Non-Confidential), dated June 27, 2024) Figure 20 (Page 49 of 67). New Brunswick Power likewise plans its system to meet a 20% capacity reserve margin (Page 44 of New Brunswick Power Corporation 2023 Integrated Resource Plan – Pathways to a Net-Zero Electricity System).

Hydro indicates that for the Reference Case Expansion Plan, the equivalent capacity reserve margin for an LOLH of 2.8 hours is 25.8%, (CA-NLH-012a). This reserve margin is higher than that used in New Brunswick and Nova Scotia presumably because of the dependence on off-island generation supplied over the LIL.

LIL Shortfall Event Criterion: The IIS should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event. A LIL shortfall event is defined as loss of both poles of the LIL direct current transmission line for a six-week period in the winter months.

Hydro elaborates on the LIL shortfall event criterion as follows (CA-NLH-007c, page 5 of 5):

> *The loss of the LIL bipole is considered a high-consequence event for the Island Interconnected System. Although there is no specific planning criterion tied to this event, mitigating the impacts of a prolonged LIL outage remains critical…*

A LIL shortfall event is the double contingency loss of both poles of the LIL for a 6-week period on the most remote area of the LIL (the most difficult point of access) during the most critical time of the year, namely, the winter period when demand on the IIS is greatest. Hydro then applies its probabilistic loss of load model to determine the amount and duration of loss of load events and decides if the resulting amounts are "acceptable". Hydro also considers loss of additional transmission (an n-3 event, or what Hydro refers to as an n-2-1 event in CA-NLH-016b) during the LIL shortfall event to determine if remaining transmission can transport generation supply to the load. In effect, Hydro considers the impact of 0 MW transfer to the IIS from the Muskrat Falls assets for 6 weeks during the most critical time of each year and assesses the loss of supply during the 6-week period to determine if additional assets are necessary.

3.4.2 Scenarios Analysis

Consistent with its planning criteria, Hydro developed its 2024 Resource Adequacy Plan ("RAP"). Hydro then analyzed numerous scenarios to determine the optimum expansion plan for the IIS. Hydro considered different load forecasts to accommodate different growth rates and penetration levels of electrification and decarbonization. Based on the load forecast, Hydro added/subtracted different supply alternatives in its model of the IIS needed to meet demand in an acceptably reliable and least cost manner based on its reliability criteria and government policy (e.g., decarbonization). Hydro considered a broad range of alternatives such as combustion turbines, additional hydro, wind generation, battery storage, additional conservation and demand management (CDM). Consistent with government net zero emissions policy, Hydro did not consider alternatives that would impact environmental emissions in an unacceptable manner. For this reason, fossil-fired generation was limited to peaking facilities such as combustion turbines; base/intermediate load fossil generation such as simple and combined cycle gas generation were not considered.

The 2024 RAP led to Hydro's Reference Case consisting of 525 MW in new capacity and 1.8 TWh of firm energy annually, although the energy requirement may be reduced by as much as 500GWh.[8]. To achieve that, the Plan includes 150 MW of combustion turbines, BDE8 at about 150 MW, up to 400 MW of wind generation, and additional sources such as additional CTs and battery storage, and CDM. Hydro states (The Power of Planning, page P.2) "*As a first step, and in recognition that our customers are counting on us to invest wisely and prudently, we recommended a Minimum Investment Required Expansion Plan*." Hydro notes that the Minimum Investment Required Expansion Plan includes about 300 MW of capacity from the Avalon CT and BDE8 (as sought through the 2025 Build Application), and an additional 85 MW of capacity and 1.4 TWh of energy from wind generation although that energy requirement might be reduced.[9].

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[8] Hydro has recently implemented the final UFLS Scheme that allows for increased LIL bipole transfer limits. With these new limits, more energy delivered over the LIL can be absorbed by the IIS. This change in the UFLS Scheme has greatly reduced constraints and the capacity provided by the LIL can now fully support Island Interconnected load, less firm contractual commitments to Nova Scotia and losses. The LIL transfer capacity has increased by about 150 MW, but in spite of this significant increase, the amounts and need dates for capacity additions are unchanged because of the LIL shortfall event criterion which assumes 0 MW over the LL for six weeks in the winter period. However, it does reduce the firm energy deficit by 450 to 500 GWh (see Table 1 in *Reliability and Resource Adequacy Study Review* – Semi-Annual Update for the Second Quarter of 2026, dated June 30, 2026)

[9] As noted in the preceding footnote, firm energy requirements are reduced by 450 to 500 GWh owing to the increase in the LIL transfer capacity.

3.4.3 Capacity Reserve Margin Analysis

Table 1 illustrates how the proposed builds would contribute to meeting Hydro's planning criteria. It employs equivalent capacity reserve margins relative to the target capacity reserve margin that Hydro indicates is equivalent to its LOLH criterion of 2.8 hours.

Table 1. Capacity Reserve Margins in 2031 under Different Scenarios (MW)[10]

	No Thermal Retirements, No New Additions	Thermal Retirements, No New Additions	Thermal Retirements, Avalon CT	Thermal Retirements, Avalon CT & BDE8	Thermal Retirements, Avalon CT, LIL Shortfall Event
IIS Firm Capacity	2119	1501	1651	1801	1651
LIL Transmission Capacity	484	484	484	484	0
Total Island Capacity	2603	1985	2135	2285	1651
Total Peak Load (including losses)	1859	1859	1859	1859	1859
Reserve Margin (%)	40%	7%	15%	23%	-(11%)
Target Reserve Margin (%)	25.8%	25.8%	25.8%	25.8%	Unknown

A number of observations follow from the figures in Table 1:

- Hydro's LOLH criterion equates to a target planning reserve margin of 25.8%, or 500 MW in 2032 for the Reference Case (CA-NLH-012a). This is in excess of the 20% planning reserve margin used in New Brunswick and Nova Scotia. Hydro indicates that a higher reserve margin is needed owing to the unreliability of the LIL and Holyrood TGS. Hydro indicates that for "*the Minimum Investment Required Expansion Plan, a 17.1% reserve margin is required, which equates to 360 MW in 2032*." This could be interpreted to mean that Hydro is accepting a lower reserve margin for the Minimum Investment Plan, but if it is to meet the LOLH criterion of 2.8 hours, a 25.8% reserve margin is necessary.

- In 2031, if the thermal generation is not retired, total IIS capacity is 2603 MW, 744 MW more than the peak IIS demand of 1859 MW, equating to a 40% reserve margin. This is well in excess of Hydro's target reserve margin of 25.8%, so reliability would be more than adequate, assuming the thermal assets continue to perform adequately.

[10] Notes:

1) Based on information provided in CA-NLH-013, Attachment 1 which uses the 2025 Slow Electrification load forecast.
2) The 25.8% target capacity reserve margin is from CA-NLH-012a for the Reference Case Expansion Plan.
3) Thermal retirements include Holyrood TGS (all 3 units), Hardwoods gas turbine, Stephenville gas turbine and the Newfoundland Power Wesleyville and Greenhill gas turbines.
4) Reserve margin is the (Total Island Capacity – Total peak Load) / Total Peak Load
5) It is assumed that the Avalon CT and BDE8 each provide 150 MW.

- Based on the LIL shortfall event criterion, if the thermal generation is not retired, total IIS capacity during the 6-week LIL outage in winter is 2119 MW, 260 MW more than the peak IIS demand of 1859 MW, equating to a 13% reserve margin. This would probably be an acceptable level of reliability during a low probability event limited to 6 weeks.

- In 2030, Hydro assumes that thermal generation will be retired including: all 3 units at Holyrood TGS (490 MW), Hardwoods (50 MW), Stephenville (50 MW), and the Newfoundland Power Wesleyville and Greenhill gas turbines (28 MW combined). The total generation assumed to be retired in 2030 is 618 MW which equates to 29% of the firm capacity located on the Island, and 24% of the total firm capacity available to supply the Island (includes imports over the LIL). With these retirements, total IIS capacity is 1985 MW which is 126 MW more than the peak IIS demand of 1859 MW, equating to a 7% reserve margin, well below the 25.8% target reserve margin. Reliability would be less than adequate if 618 MW of thermal generation is retired in 2030.

- Under the LIL shortfall event criterion, assuming 618 MW of thermal generation capacity has been retired, total IIS capacity is 1501 MW, 358 MW less than the peak IIS demand of 1859 MW, equating to a negative 19% reserve margin. In effect, IIS capacity is reduced by 1102 MW (618 MW of thermal retirements and 484 MW from the LIL), or 42%. Clearly, with thermal generation retirements, reliability would be less than adequate during a 6-week LIL outage in winter.

- While adding the Avalon CT improves the reserve margin from 7% to 15%, it remains below levels judged to provide acceptable reliability. Capacity additions would be needed, especially under the LIL shortfall event criterion, which would be underwater at negative 11%.

- Adding both proposed builds would improve the reserve margin to 23%, a little less than the target reserve margin of 25.8%.

In summary, significant new capacity is required to offset thermal retirements and assist in meeting Hydro's target reserve margin. Even more capacity is required to meet Hydro's LIL shortfall criterion. The Consumer Advocate believes that some combination of additional supply and demand measures would be needed.

4. Should the Avalon CT Be the First Choice of Capacity Additions?

4.1 Expansion Plan Analysis and Bates White Support

There is a convincing case in favour of the Avalon CT as the first substantive capacity addition in preparation for the retirement of Hydro's thermal capacity. The Expansion Plan Analysis in the Evidentiary Update shows that under the slow electrification load forecast, the Avalon CT is the choice for first capacity addition in four out of six scenarios.[11] The two in which it is not first choice are those where underlying assumptions especially disadvantage the CT – where costly fuel burn-off is needed or where its capital cost escalates relative to other capacity additions.[12]

Bates White also strongly supports the Avalon CT. Its Phase 2 Expert Report (page 1) states:

> *Bates White recommends that the Board consider approving the Avalon CT component of Hydro's Build Application, with a current estimated in-service date in March 2030. The evidence in the record supports the need for the Avalon CT as necessary to accommodate the retirement of the Holyrood TGS. Bringing the Avalon CT into service as early as feasible will allow for the orderly, and possible progressive, retirement of the Holyrood units, mitigating cost while supporting system reliability.*

4.2 Location on the Avalon

Holyrood TGS sits just outside the major load centre of St. John's, which has made it an ideal plant to support load during the winter, when transmission across the Island from west to east has been constrained. With the addition of the LIL, the direction of flow is expected to reverse for much of the year, and Hydro has done significant work to improve west-to-east transfer capability. Even so, assets on the Avalon remain valuable. The current models show that load shedding on the Island will most likely be driven by failures of the LIL; during such outages, the power sunk to the Avalon is reduced or eliminated entirely, and the high-demand Avalon Peninsula becomes reliant on flows from off the peninsula through the precarious Isthmus transmission corridor. Avalon-sited generation may not be an absolute requirement but, all things being equal, new generation on the system is preferred on the Avalon.

The Avalon CT would be located on the Avalon Peninsula where the IIS load is concentrated. This would greatly reduce any need for substantial transmission upgrades.

4.3 Avalon Combustion Turbine vs. Bay d'Espoir Unit 8

Engineering considerations favour the Avalon CT over BDE8. BDE8 would concentrate still more of the Island's capacity at a single station drawing on a single reservoir system. Hydro's generation adequacy modelling assumes that outages among the Bay d'Espoir units are uncorrelated, but recent experience suggests otherwise: the frazil ice event this past winter took all of the units at Bay d'Espoir out of service simultaneously, and cracks have been identified in the penstock. Without necessarily recommending changes to Hydro's adequacy modelling, the Consumer Advocate cautions that placing another unit at Bay d'Espoir puts more eggs in a single basket, whereas the Avalon CT is a distinct resource at a distinct location.

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[11] 2025 Build Application - Avalon Combustion Turbine Evidentiary Update, Table 2, page 5.
[12] In the case of a higher load growth forecast, the Reference Load Forecast, the Avalon CT is always the first capacity choice but others would be added at the same time.

Further, BDE8 would add capacity but no energy: it would draw from the same reservoir as the seven existing units, and the Upper Salmon and Granite Canal plants upstream of Bay d'Espoir are already bottlenecks to generation at the plant. Additional capacity there would exacerbate that constraint. The Avalon CT's fuel is expensive, but it is independent of the Bay d'Espoir system's hydrology. Finally, a substantially greater portion of the Avalon CT's costs has already been expended through the early execution process than is the case for BDE8, and those expenditures are not recoverable. That asymmetry is properly considered when comparing the two projects.

While it appears that the Avalon CT is the appropriate first capacity addition in anticipation of thermal retirements, it does not follow that the other component of the 2025 Build Application should be second or even approved. Changes in rate design and other measures on the demand side and incremental additions on the supply side such as battery storage and wind generation are among the options that should be further explored before undertaking another large, indivisible project costing more than $1 billion.

Wind in particular, offers the advantage of providing both capacity and energy and it can be added incrementally and geographically dispersed. Moreover, the firm capacity associated with wind is now more than previously anticipated. As stated in Hydro's 2026 General Rate Application (Chapter 6 – Rates and Regulations, page 6.9) in referring to a study completed in late 2025, "The 2025 study found that the marginal Effective Load Carrying Capability for 50 MW of wind is 43% demand, an increase of approximately 20% from the previous 2018 study." This is an encouraging finding.

In short, acceptance of the Avalon CT as the appropriate first capacity addition does not imply that the other element of the 2025 Build Application, BDE8, should be the second. As noted by Bates White (Bates White Phase 2 Expert Report of Vincent Musco and Collin Cain dated February 3, 2026, page 2) "*The IIS does not need both the Avalon CT and BDE Unit 8 by 2031, as long as Hydro's existing thermal assets remain operational.*"

5. *Is the Cost of the Avalon CT Reasonable?*

5.1 Total Cost and Impact on Ratepayers

At the time of the 2024 RAP, the estimated (AACE Class 5) cost of the Avalon CT was approximately $500 million (CA-NLH-001 regarding the Additional Early Execution Application). Various adjustments as well as refinements to a Class 3 estimate led to the $891 million requested authorized budget for the project in the 2025 Build Application as submitted on March 21, 2025. Subsequently, and reflecting cost pressures due to surging market demand for CTs, Revision 1 of the 2025 Build Application increased that amount to $995.9 million, just short of $1 billion.

That is a substantial cost. If the cost is recovered from IIS consumers in their electricity rates it will mean rates will be higher than otherwise. Hydro's estimated pro-forma incremental customer rate impacts shows an impact of 1.43 cents per kWh in 2031, the first full year of operation for the Avalon CT. [13] In subsequent years to 2040, Hydro estimates the rate impact would range from 1.3 cents to 1.42 cents per kWh. In percentage terms, the biggest impact would be in 2031. In that year, without the Avalon CT (or equivalent major project) the estimated average customer rate is 19.61 cents per kWh but that rate would be 21.04 cents if the CT's cost is in rates, which is 7.3% higher.

It is not clear whether the Rate Mitigation Plan would cover such large additions to capacity. However, ratepayers will have to pay whether in their rates or through their taxes/public services along with other taxpayers. Therefore, the key consideration is the cost of the project itself.

At nearly $1 billion, the cost of the Avalon CT is deeply troubling, especially for a project that provides very little energy and does not offer nearly enough capacity to satisfy planning criteria – a big price tag for only a partial solution. On the other hand, the Holyrood TGS is becoming less reliable and will have to be closed by 2035 in accordance with the federal Clean Electricity Regulations.

5.2 Management Reserve

A substantial component of the cost estimate for the Avalon CT is for a management reserve. It is $121.6 million out of a total requested authorized budget of $995.9 million, and that requested budget also includes allowances for escalation, interest during construction, and a contingency. The management reserve makes the budget approximately 14% higher than otherwise.[14] The need for this management reserve, especially one of such a magnitude, is highly questionable for three reasons.

First, as Bates White points out (Phase 2, Expert Report, page 8):

> *The concept of a management reserve is not unprecedented, but it also not widespread. For example, CAMS notes that management reserve is not typically seen in the power generation industry for projects like the Avalon CT. The management reserve is a set-aside source of funds to be used only if unforeseeable, high-impact events occur that have substantial impacts on project costs. Having such funds set aside allows those high-impact events to be addressed with little or no impact on project development and schedule. In principle, a management reserve can help ease the regulatory burden of addressing unexpected or low probability events and facilitate efficient project management under such circumstances. However, an expansive initial budget approval could also blunt project management discipline, with the management reserve providing cover for poor cost estimation and poor project management. The purpose of the Management Reserve should be to provide additional, needed funds due to the manifestation of the strategic risks and should not be used as a backstop for poor cost estimates, poor contingency estimates, or poor project development and management.*

[13] Response by Hydro dated May 15, 2026 to the May 5, 2026 request from the Board for further information; see response to Request 5, Attachment 1.

[14] 121.6/(995.9 -121.6) = 13.9%.

Based on this advice, approval of management reserves should be done sparingly and only in exceptional circumstances.

Second, as noted earlier, Hydro has had access to early execution funding for the project. The Early Execution Application of March 12, 2025, led to approval of $30,710,000 and the Additional Early Execution Application of December 12, 2025 led to an additional $29,294,000. Thus, Hydro has $60 million in funds to advance the project and allow it to enter into contractual arrangements to secure needed components. Hydro has also submitted its June 2026 Phase II Additional Early Execution Application, which seeks a further $35.4 million. If approved, Hydro will have had nearly $95 million (more than 10% of the project cost, excluding the management reserve) prior to project approval. This level of pre-funding must surely help Hydro address cost and availability pressures. The costs may have been higher than expected, but the use of these funds must be reducing uncertainty and eliminating "unknown unknowns".

Thirdly, it is noteworthy that the Board did not accept provision for a management reserve in Hydro's June 20, 2025 Application for the Life Extension of Bay d'Espoir Unit 7. In its Reasons for Decision in Relation to Order No. P.U. 12(2026), the Board noted (page 10) that this was the first time an application had sought a management reserve. While acknowledging that a management reserve may be appropriate in some cases in order to address uncertainty and execution risk on large complex projects, the Board decided that it was not warranted for the life extension of Unit 7. The Board approved the project but not the management reserve component of the budget. While the Avalon Project is a large project, it is not a new type of venture or technology for Hydro. Hydro has considerable experience with CTs. Also, the CT will be located in an easily accessible location close to amenities and on an existing Hydro property. It does not appear to be complex relative to Hydro's capabilities and built-up expertise. Like Unit 7, the case for a management reserve for this project is not strong.

5.3 AI and Data Centres

The market context bears both on the reasonableness of the price and on the question of timing. The rapid rise of artificial intelligence and the buildout of data centres has produced a rush on generation equipment across North America. Orders for combustion turbines now carry waitlists of several years, where units are available at all. This environment has increased the price of the Avalon CT even relative to a year ago. It is likely that this supply crunch will eventually ease, but that may take many years as turbine manufacturers ramp up capacity and AI finds application across more of the economy.

Two implications follow. First, there is little basis to expect near-term price relief. Second, Hydro now holds an executed contract, secured through a competitive process, for which considerable non-recoverable sums have already been paid through early execution; abandoning that position would not remove the requirement for new assets, and re-procuring an equivalent turbine today would very likely cost more.

The Consumer Advocate accepts that global demand for combustion turbines is driving up prices, placing purchasers in a difficult bargaining position. That acceptance does not, however, extend to the risk allowances layered on top of the package price - the Management Reserve in particular - nor does it relieve Hydro of its burden to demonstrate that the total authorized budget is reasonable.

6. Unresolved Concerns and Questions

A number of matters remain unresolved on this record, and warrant the Board's attention:

6.1 Likelihood of Delays in Retiring Holyrood TGS

In its application, Hydro indicates that it plans to retire Holyrood Thermal Generating Station ("Holyrood TGS"), and the Hardwoods and Stephenville gas turbines in early 2030. Following these retirements, based on Hydro's LOLH criterion, the Minimum Investment Plan indicates that new capacity resources are required including 150 MW in 2031 and an additional 150 MW in 2034. Hydro also recommends moving the second capacity addition ahead to 2031.

The premise is that the new capacity assets will permit the full retirement of the Holyrood TGS - however there is a real likelihood that Holyrood TGS will stay operational longer than the anticipated plan to retire the plant in 2030, particularly if the approval of a second capacity resource in 2031 is not approved or delayed. There is also nothing in the Application that binds Hydro to retire one or more units once the Avalon CT is in service.

As such, there is a strong likelihood that Hydro will continue to operate Holyrood TGS if only the Avalon CT is approved. The impact on ratepayers is that ratepayers will find themselves paying simultaneously for the MFP, for the Avalon CT, and for a Holyrood TGS.

Our position is that it is vital that new capacity additions accomplish what the LIL did not: the full retirement of Holyrood TGS. Hydro should therefore be required to file with the Board updated plans and schedules for the retirement of the Holyrood units (including consideration of the orderly, progressive retirement contemplated by Bates White) and to report regularly to the Board.

6.2 Reasonableness and Probability of the LIL Shortfall Criterion

As noted, the LIL shortfall event criterion equates to the loss of both poles of the LIL (an n-2 event), on the most remote section of the LIL requiring 6 weeks to repair, at the most critical time of the year (winter). It then assumes there will be loss of generation resulting in lost load as determined by Hydro's probability modelling, and loss of additional transmission during the event. This is a lot of "what ifs". In effect, Hydro is planning the IIS on the basis that there will be 0 MW provided to the IIS by the Muskrat Falls assets during the most critical 6-week period in winter.

A notable gap in Hydro's record is the quantification of the probability of a LIL shortfall event, which Hydro was unable to answer in CA-NLH-008c. The 2024 RAP requires billions of dollars for capital expenditures largely to be better positioned to deal with the impact of a LIL shortfall event. In CA-NLH-007 Hydro indicates that the lower end of the assessed range for the LIL equivalent forced outage rate is 1% but states "*there is still a risk of extended outages…*" This implies that in the approximately 1% of cases where there is a LIL bipole outage there is some probability that the outage would be a prolonged one. Thus, the probability of a bipole outage that leads to a prolonged LIL outage may be very low. It would have been extremely helpful to know a reasonable estimate of it. Given that a LIL shortfall would have a high negative impact on IIS consumers, a reasonable estimate of the chances of such an event is informative. If a LIL shortfall is a one-in-100-years event then there is a weak case for spending billions of dollars to add capacity, but if it is a one-in-ten-years event, the case for substantial expenditures would be stronger.

Further, the Board has not yet approved the LIL shortfall event as a planning criterion. Hydro states: (CA-NLH-012b)

> *The LIL shortfall criteria was first introduced into the Reliability and Resource Adequacy filings in 2018, and while valuable operational experience has been gained on the LIL since commissioning, the LIL shortfall criteria has not formally been approved by the Board of Commissioners of Public Utilities.*

Hydro should have a plan for reducing the likelihood of such an event and for dealing with one should it happen. Hydro should not use the possibility of a LIL shortfall event as a planning criterion for committing large capital expenditures unless it can provide a reasonable range for the probability of such an occurrence and demonstrate that such capacity projects are less costly than expenditures that would reduce the probability of a LIL shortfall or that would expedite restoration.

6.3 Applicability of the Clean Energy Regulations to Holyrood TGS

There is some question as to whether the CER binds Holyrood TGS. The CER's requirements appear to be tied to jurisdictions subject to North American Electric Reliability Corporation ("NERC") reliability standards. The Newfoundland and Labrador Interconnected System is not currently subject to NERC's standards, and the applicability of the 2035 retirement requirement to Holyrood has not been tested.

The Consumer Advocate recommends that Hydro obtain a legal opinion to determine whether Holyrood TGS is bound by the CER and, if it is, what restrictions would be placed on the operation of the plant. If the 2035 date is not a legally binding constraint, then the timing of Holyrood TGS' retirement is even more clearly a matter of Hydro's planning judgment rather than external mandate - and the urgency said to flow from a fixed deadline should be weighed accordingly.

6.4 Wind Generation Update

With respect to Hydro's exploration of wind possibilities, in Hydro's report entitled *Reliability and Resource Adequacy Study Review* – Semi-Annual Update for the Second Quarter of 2026, it is stated (page 2):

> *As a first step in the call for power process, Hydro issued a Request for Expression of Interest ("EOI") on July 9, 2025, for the supply of energy and capacity that, in combination, can provide for up to 150 MW of firm capacity and up to 500 gigawatt hours ("GWh") of firm energy. The Request for EOI closed on September 2, 2025, and Hydro received 17 responses. The next step was*

to evaluate the responses; however, since that time, the call for power process has been and remains paused. Engagement with the Government of Newfoundland and Labrador continues, and Hydro will provide an update to the Board on progress toward such procurement in its next semi-annual report in the fourth quarter of 2026.

In spite of the need for capacity and energy identified in Hydro's Minimum Investment Required Expansion Plan, and the success of the wind generation EOI, the process appears to be paused. This is puzzling given the seemingly urgent need for capacity and energy, the environmental attributes of wind generation, and the ability to bring wind generation on in smaller blocks to coincide with growth in demand - reducing risk and cost (compared to BDE8 with a single 150 MW block). The Board may want to push for updates on the wind generation EOIs and the status of the call for power process.

6.5 Newfoundland Power Generation

In its 2027 Capital Budget Application submitted May 29, 2026, Newfoundland Power states that it anticipates filing a supplemental capital budget application in the third quarter of 2026 for the refurbishment of thermal generation facilities at Greenhill and Wesleyville with completion of the refurbishment work by 2031. It is anticipated that the refurbishment project would include an up-rate of the facilities from 28 MW to 48 MW. The total cost is estimated at $231 million.

The refurbishment raises some questions: 1) Will these gas turbines be available for supply to the IIS beyond 2030, and if so, how much capacity will they provide, and 2) Are there lower cost options for gas turbine capacity?

Hydro states with respect to the Wesleyville and Greenhill gas turbines (CA-NP-030):

Hydro believes it is premature to consider the reasonableness of a preliminary estimate that is subject to change, without the detail necessary to support any review. Once Newfoundland Power has filed its application for the refurbishment project, Hydro will consider the estimate and its foundation, including whether the estimate considers the volatility of market pricing, to determine the estimate's reasonableness and whether there is sufficient information to determine any impact on Hydro's analysis of system needs.

Hydro assumes that Newfoundland Power's Wesleyville and Greenhill gas turbines will be retired in 2030, removing 28 MW of capacity from the IIS. Hydro's assumption in scenario analyses is that these gas turbines provide 0 MW of capacity to the IIS beyond 2030, which perhaps should reflect the uprate of the facilities.

Secondly, the cost of the Avalon CT is $996 million and Hydro indicates that costs for CTs could increase by almost 200% by 2027 (2025 Build Application - Avalon Combustion Turbine Evidentiary Update, page 13). Newfoundland Power suggests that two 24 MW CTs can be replaced for $231 million, or about $4813/kW (Given market pressures, there may be an upward revision in that figure in Newfoundland

Power's forthcoming application). The Newfoundland Power CTs price compares to $996 million for the 150 MW Avalon CT, or $6640/kW.

Newfoundland Power has not yet submitted its application, but it draws into question the reasonableness of Hydro's assumption relating to the retirement of these facilities and the relative cost of the Avalon CT. As noted, Hydro has not reviewed the accuracy of Newfoundland Power's cost estimate and there is inadequate information available on the record. However, the Board may want to further explore Hydro's retirement and gas turbine cost assumptions after it has additional information on the Newfoundland Power refurbishment/uprates.

7. The Alternative of Deferral

The Consumer Advocate has given thorough consideration to the alternative of recommending that the Board decline to approve the Avalon CT at this time.

There is a genuine case for waiting two to five years to see how the landscape develops. The extraordinary pricing Hydro faces is attributed to a demand surge that may prove temporary; if the market for combustion turbines cools as manufacturing capacity catches up, prices could fall materially. Operational experience with the LIL continues to accumulate, and if the line improves, the capacity said to be needed against its failure would shrink. The condition of Holyrood TGS might remain stable, the results of wind procurement would become known, and the Newfoundland Power generation additions may be operational by then. On this view, deferral purchases better information at the price of delay.

But the risks of waiting are, in the Consumer Advocate's judgment, greater. There is no evidence that the market pressure driving gas turbine prices is abating, and considerable evidence that it is not: the data centre and AI trends show every sign of accelerating, and with it, global competition for gas turbine units. There is a real risk that if the Board defers the Avalon CT project and the market prices continue to climb, ratepayers could face a bill substantially above the original estimate, potentially double in 2027 or more. Multi-year equipment waitlists mean that a deferral of two years could translate into a considerably longer in-service delay. Meanwhile, Holyrood TGS' condition is likely to worsen with each passing winter: its derated adjusted forced outage rate has averaged almost 30% over the past five years and reached 43% in 2024. Every year of delay is another year of leaning on an asset that is expensive, unreliable, and inflexible. Further, Hydro currently holds an executed contract at a known price, and has already spent non-recoverable early execution funds. Walking away forfeits that position without eliminating the need.

These conditions present a gamble that the Consumer Advocate is not prepared to ask ratepayers to take: the potential savings from waiting are speculative, while the costs of being wrong - higher prices, longer delays, and continued reliance on a failing Holyrood TGS - are substantial, compounding, and unaffordable for ratepayers.

8. *Conclusion and Recommendations*

8.1 The Consumer Advocate's Position

The Consumer Advocate supports the approval of the Avalon CT, but does so with significant reluctance and reservation. The reality confronting the IIS is not of ratepayers' making, and it leaves the Board without attractive choices. Holyrood TGS is old, expensive, and increasingly unreliable; the Muskrat Falls Project cannot accomplish that retirement on its own. When Holyrood TGS, Hardwoods, and Stephenville and the Newfoundland Power Wesleyville and Greenhill gas turbines are retired, 618 MW of firm capacity (29% of on-Island capacity) leaves the system, and the analysis demonstrates that the post-retirement reserve margin collapses to 7%, far below Hydro's 25.8% target. While all 618 MW need not be replaced, a substantial amount of new firm capacity will be required. That need is real, and the Consumer Advocate does not dispute it.

Within that constrained reality, the Avalon CT is the best available option. It is the first-choice capacity addition in the majority of Hydro's expansion scenarios; it is endorsed by the Board's expert, Bates White; it sits on the Avalon Peninsula, where the load is concentrated and where the system is most exposed during a LIL outage; and it avoids concentrating further risk at Bay d'Espoir. The Consumer Advocate's position is that the Avalon CT, in combination with wind generation and a range of other supply and demand measures, may well be sufficient to meet the system's needs, particularly under Hydro's LIL reliability assumptions.

For these reasons, the Consumer Advocate supports the approval of the Avalon CT. Reliable electricity, especially in a winter-peaking system where many homes are heated with electricity, is essential. Our reliance on electricity is growing as more of our economy is shifted online. Significant rolling blackouts as experienced during DarkNL would be even more impactful on our Province today as many businesses would not operate and many workers could not perform their jobs. Reliable electricity becomes even more important as our economy becomes more reliant on AI and technology.

The Build Application for the Avalon CT represents an indisputably steep price for additional capacity on the IIS, but this is the reality of the Province's situation: ratepayers are being asked to continue to pay for reliability they were told the MFP would deliver. The Reference Case presented by Hydro would not be as extensive if the MFP delivered reliable power to the Island and had enabled the proper retirement of Holyrood TGS. It is deeply unfortunate that the Avalon CT and other expansion additions are costs that IIS ratepayers and taxpayers will bear for decades, on top of the costs of the MFP.

8.2 Recommendation

The Consumer Advocate recommends that the Board:

1. approve the Avalon CT as a necessary capacity addition to the Island Interconnected System, subject to the concerns and conditions set out above;

2. decline to approve the Management Reserve of $121.6 million as requested, and require that any reserve amount permitted remains subject to Board approval or prudence review at the completion of the project, with the burden of prudence resting on Hydro;
3. direct Hydro to undertake continual structural analysis of the LIL and to identify, on a least-cost basis, measures to reduce the likelihood and consequences of a LIL shortfall, and to report the results to the Board;
4. direct Hydro to obtain a legal opinion on the applicability of the CER to the Holyrood TGS; and
5. require Hydro to report to the Board on the results of its paused wind Expressions of Interest, and on the Newfoundland Power gas turbine refurbishment once filed, before committing ratepayers to further major capacity additions.

Please contact the undersigned if you have any questions relating to this submission.

Adrienne Ding
Interim Consumer Advocate
323 Duckworth Street, P.O. Box 5955
St. John's, NL A1C 5X4
Telephone: (709) 853-5530
Email: consumeradvocate@odeaearle.ca; ading@odeaearle.ca
Fax: (709) 726-9600

Justin King
Counsel to the Consumer Advocate
Email: jking@odeaearle.ca