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September 11, 2025

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: 2025 Build Application – Request to Hydro to Provide Additional Information – Hydro's Reply

On March 21, 2025, Newfoundland and Labrador Hydro ("Hydro") filed its application for capital expenditures for the purchase and installation of Bay d'Espoir Unit 8 ("BDE Unit 8") and the Avalon Combustion Turbine ("Avalon CT") (collectively, "2025 Build Application"). The Board of Commissioners of Public Utilities ("Board") subsequently engaged their expert, Bates White Economic Consulting, LLC ("Bates White"), to review Hydro's submission and provide a report to the Board. Bates White submitted their report to the Board on June 26, 2025 ("Bates White Report").

In correspondence to Hydro on July 22, 2025,[1] the Board requested additional information on Hydro's application based on conclusions and recommendations identified within the Bates White Report. Please find enclosed Hydro's responses to the Board's request in questions 1 through 14.

Hydro's response to question 2 contains commercially sensitive information that, if made public, would undermine Hydro's ability to obtain goods and services at the lowest possible cost and therefore negatively impact Hydro's customers. Hydro has considered the practices of other utility regulators in Canada in determining the level of redaction to apply to the information. The information Hydro requests to be kept confidential is that which could be reasonably expected to:

- **i.** Result in undue material financial loss or gain to a person or party directly affected by the hearing or other proceeding;
- **ii.** Cause significant harm or prejudice to a party's competitive or negotiating position; or
- **iii.** Interfere with the contractual obligations of a party.

Some of the information redacted within question 2 includes breakdowns of cost estimates for supply options such as Battery Energy Storage Systems ("BESS"), including engineering, construction, escalation, and Owner's costs. This information has been redacted as, if available, it would allow the extrapolation of the same information for the projects proposed in the 2025 Build Application. That information, if available to suppliers or potential suppliers, could provide the suppliers with a competitive advantage

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[1] "Newfoundland and Labrador Hydro - 2025 Capital Budget Supplemental Application -Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine - To Parties – Request to Hydro to Provide Additional Information," Board of Commissioners of Public Utilities, July 22, 2025

and potentially influence future bidding strategies or negotiations. The availability of the information could enhance the suppliers' ability to command higher prices, limit competitive pressure, and ultimately drive an increase in costs for the utility and its customers. Particularly for projects with substantial capital expenditures such as these, Hydro believes that maintaining the confidentiality of information such as this directly supports the best interests of its customers.

The other information redacted within question 2 is consistent with the remainder of the 2025 Build Application record. For further details on the rationale for redaction, please refer to Hydro's response to the Confidential Information Inquiry.[2]

The information contained within Hydro's responses also serves to clarify some of the information upon which Bates White based their assumptions and analysis, to ensure fulsome consideration of the electricity system and its hydrological resources. The following is a high-level synopsis of Hydro's responses to the Board's request and the Bates White Report recommendations.

Additional Expansion Plan Sensitivities

For the purposes of the requested additional information, Hydro ran a total of nine sensitivities; these included removing limitations on combustion turbines ("CT") and including BESS, as recommended by the Bates White Report. None of these sensitivities meet Hydro's planning criteria.

Hydro's analysis ultimately found that in every scenario, the initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8. Hydro's analysis also continues to recommend advancing the Avalon CT from 2035 to 2031, in order to ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a manageable level should a Labrador-Island Link ("LIL") shortfall event occur. In all scenarios where batteries greater than 50 MW are selected by the model, the impacts during the LIL shortfall scenario are worsened beyond the level of previously demonstrated rotating outages, further supporting the need for additional On-Avalon generation.

Load Forecast

In their report, Bates White indicated that Hydro did not incorporate several recommendations made in their review of the 2023 Load Forecast Report, stating:

> While the 2024 Load Forecast addresses our general recommendations for timely updates, it does not incorporate several recommendations made in our review of the 2023 Load Forecast.[3]

However, this is not accurate. The impacts of Bates White's recommendations on the 2024 Slow Decarbonization load forecast compared to the 2023 Slow Decarbonization load forecast were addressed in detail as presented in Technical Conference #1 on September 17, 2024.[4] These changes were incorporated into Hydro's 2024 Load Forecast Report as detailed in response to question 7.

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[2] "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Confidential Information Inquiry – Hydro's Reply," Newfoundland and Labrador Hydro, May 9, 2025.
[3] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025, para. 25, p. 19.
[4] "2024 Resource Adequacy Plan – Technical Conference #1: Load Forecast/Reliability Planning Criteria," Newfoundland and Labrador Hydro, September 17, 2024.

Hydrological Constraints

The Board requested an additional LIL Shortfall Analysis run to address potential hydrological resource constraints identified in the Bates White Report. Alternatively, the Board advised that Hydro could provide additional evidence on the matter.

The hydrological resource constraints outlined in Section III.H of the Bates White Report, particularly Figure 8, appear to be based on a misinterpretation of the information Hydro provided and, therefore, are not valid constraints.

In their analysis, Bates White isolated the Long Pond Reservoir and did not consider the water balance of the Bay d'Espoir system. Reservoir storage in the Long Pond Reservoir, which supplies the Bay d'Espoir Hydroelectric Generating Station, cannot be accurately determined by simply subtracting the maximum operating level from the low supply level from the maximum operating level, regardless of the season. Inflows into that reservoir are comprised of natural inflows from the watershed, turbined flows from the Upper Salmon Hydroelectric Generating Station, and, if necessary, bypass flows from North Salmon Dam. As a result, the reservoir receives a continuous and substantial flow volume of water into the Long Pond Reservoir, and its operation must adhere to defined reservoir operating limits (i.e., the maximum operating level and the low supply level).

Hydro has provided the Hydrology and Feasibility Study for BDE Unit 8, completed by Hatch Ltd. ("Hatch"), within its previously filed evidence; that study confirmed that the Bay d'Espoir system has adequate firm hydrology with the addition of Unit 8.[5] In its 2024 Resource Adequacy Plan, Hydro provided an assessment of the impact of an extended LIL outage on Island reservoir storage by the same independent hydrology expert, Hatch, who determined that the Bay d'Espoir hydrological system can support the addition of up to approximately 150 MW of generation.[6] This analysis considered all historical hydrological data, including critical dry sequences.

Results from <u>all simulations</u>, including the LIL outage case simulations, indicate that the Island system has adequate reservoir storage with the addition of BDE Unit 8. As both of the referenced reports have been previously filed as part of the 2025 Build Application, no additional analysis has been completed.

Uprate of Unit 7

The Board queried whether Hydro would see any merit in including a capacity increase to Bay d'Espoir Unit 7, if Unit 8 were to be delayed beyond the dates proposed in the Build Application. The Board also requested information regarding the reasoning behind Hydro's decision to not include an uprate of Unit 7.

There is a finite amount of hydraulic capacity available in the Bay d'Espoir system, which limits the efficient incremental capacity available for consideration across both Unit 7 and the planned Unit 8.

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[5] *"Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8 – Addendum Report",* Hatch Ltd, March 19, 2025. Provided in "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 1, att. 2.

[6] "Impact of Prolonged Loss of LIL on Island Reservoir Levels," Hatch Ltd, July 2, 2024, provided in "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, att. 5.

Hatch's Hydrology and Feasibility Study for the Potential Bay d'Espoir Hydroelectric Generating Unit No. 8 Study confirmed that the existing system can support an optimized capacity increase of 150.1 MW with Unit 8.[7] This establishes a practical upper limit on incremental capacity, which must be strategically allocated—further supporting the case against diverting capacity to Unit 7.

The Uprate Report identified that an increase in the capacity of Unit 7 may result in less efficient operation over the typical and planned operating range of the unit;[8] resulting in increased water usage in a hydrologically constrained system. As a result of the hydrological constraints, an increase in the capacity of Unit 7 would have significant potential to result in a reduction to the capacity of Unit 8. This reduction would necessitate substantial re-engineering of Unit 8, which would further compound delays in the implementation of both projects.

Given the overall hydrological constraints, Hydro notes that the addition of Unit 8 itself effectively constitutes an uprating of the Bay d'Espoir system to the maximum incremental capacity available from the system. Hydro considers the addition of Unit 8 to be the most efficient and optimal method of achieving this uprate, rather than pursuing a modification to Unit 7, which has the potential to impact overall system efficiency and risk delaying the refurbishment of existing capacity.

Transmission Constraints

As with the hydrological constraints issue above, the Board requested analysis or additional evidence regarding the transmission constraints precluding delivery to the Avalon Peninsula. The transmission constraint outlined in Section III.H of the Bates White Report, specifically the assessment by Bates White, which concluded that only 67 MW could be delivered to the Avalon during normal operation, is incorrect.

With the LIL in service, the total transfer capacity eastward from Bay d'Espoir is 680 MW. Given the observed Bay d'Espoir east flow of 340 MW in Hydro's peak load flow case (Winter 2034–2035), this leaves approximately 50% of the transmission capacity unused during normal operation.

Further, Hydro's analysis (referenced in Hydro's response to part b) of the Board's question 3) confirms that the volumes are deliverable to the Avalon in all hours and are not impacted by transmission constraints under normal operating conditions (i.e., LIL is in-service and Avalon generation is available). **Hydro's analysis clearly demonstrates that the Bay d'Espoir to Soldiers Pond transmission system does not constrain Hydro's ability to deliver BDE Unit 8 power to the Avalon Peninsula, and capacity is fully deliverable during normal operation and even during abnormal operations, with the exception of rare circumstances involving multiple failures.**

Hydro acknowledges the concerns raised by the Board and parties regarding transmission system constraints that may limit supply to the Avalon Peninsula during a LIL bipole outage once the Hardwoods Gas Turbine and Holyrood Thermal Generating Station ("Holyrood TGS") have been retired. As such,

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[7] While this is slightly below Unit 8's full capacity of 154.4 MW due to modeling constraints, Hydro expects that full capacity can be achieved through broader system optimization.
[8] "Uprate Report," Hatch Ltd, June 27, 2024, sec. 3.1.1, pp. 3–4 provided in "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, att. 2.

Hydro will advance the filing of its Remedial Action Scheme ("RAS") Study to the Board and parties in the coming weeks.

Hydro has received the final study from its consultant, TransGrid Solutions Inc., which has concluded the following:

- The RAS is confirmed to be an effective solution in a LIL Shortfall scenario. It enables increased flows to the Avalon Peninsula to meet Hydro's criteria.
- The RAS can be implemented in concert with BDE Unit 8 and the Avalon CT to eliminate the need for additional transmission upgrades in the Minimum Investment Required Case.
- Increased dynamic voltage support would be needed if Hydro were to not develop the Avalon CT.

As a next step, Hydro will work on the engineering and design of the RAS solution. While cost estimates have not yet been developed, it is understood that implementation will involve modifications to protection and controls relaying. As a result, the costs associated with a RAS solution are expected to be significantly lower than those of constructing a new transmission line and have no impact on Hydro's selection of BDE Unit 8 and the Avalon CT as preferred supply solutions.

Based on the developments regarding the RAS, noted above, Hydro will not need to pursue the construction of a new transmission line in the corridor between Bay d'Espoir and Soldiers Pond in the near term. While transmission line construction will not be required in support of the proposed projects in the 2025 Build Application, Hydro will continue with its commitment to work with a consultant on the Transmission Feasibility Study to refresh cost estimates.[9]

Separation of Projects Within the 2025 Build Application

Hydro does not oppose changes in the regulatory process that would improve process efficiency and enable the timely approval of one or both resource options. Hydro is therefore not opposed to the possible separation of the process for review of the two projects, nor an earlier review of the proposed Avalon CT, provided that these changes would not constitute a pause or delay in the review process of BDE Unit 8. Hydro reiterates that its analysis for response to this request for information ultimately found that in every scenario, the initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.

Together, these projects form part of Hydro's recommended Expansion Plan as the first step to meet Island Interconnected System reliability, enable the retirement of aging thermal assets, and provide the additional benefit of diversity of supply, further reinforcing reliable capacity to the system. These proposed assets are complementary to one another, collectively mitigating a number of key risks including: (i) availability of fuel supply through use of hydroelectricity, (ii) availability of hydrological resources and mitigation of transmission constraints through the inclusion of thermal energy near the load center, (iii) providing system reliability during a shortfall of the LIL; and (iv) adherence to Clean Electricity Regulations.

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[9] A new transmission line between Western Avalon Terminal Station and Soldiers Pond Terminal Station was previously identified as a potential upgrade requirement. This transmission line was estimated to cost approximately $150 million.

Delays in the approval of either project risk delaying the retirement of units at the Holyrood TGS, which could result in the continuation of annual costs of up to $120 million, in addition to costs associated with project delays. Hydro believes it is important to consider these costs when contemplating changes in process that could delay the approval of either project, when **both** are required to meet system reliability.

Decision Timeline for the 2025 Build Application

Assuming the procurement commitments estimated in the original early execution budgets do not materially increase, Hydro anticipates that it can continue to execute its early execution work activities into the first quarter of 2026.

If approval by the Board will be delayed beyond that timeframe, an additional early execution application would be required. Hydro anticipates that the magnitude of costs will be much higher, and as such, the application would include a request for cost recovery.

Any delay in approval introduces risk to both projects, particularly from a vendor confidence standpoint. Therefore, Hydro believes that the most efficient and least-cost process for customers to mitigate further cost escalation due to schedule delays remains approval of the 2025 Build Application in the fourth quarter of 2025.

Conclusion

The information provided herein addresses the recommendations made and issues raised by the Bates White Report, including hydrology and transmission constraints related to the installation of BDE Unit 8. **BDE Unit 8 remains the least-cost alternative to reliably meet future electricity demand in an environmentally responsible manner and has been chosen as the first supply resource in every scenario analyzed.**

The Avalon CT is the best supply resource to provide On-Avalon generation at the load centre, is compliant with Clean Electricity Regulations, meets the requirements of the LIL Shortfall Scenario and provides overall system reliability. Hydro's analysis in question 3 clearly demonstrates that **BESS would be less effective than the Avalon CT in a shortfall scenario, and confirms that the system can expect to see more and deeper outages with BESS compared to the Avalon CT**.

These proposed assets provide the additional benefit of diversity of supply options and are complementary to one another, collectively mitigating a number of key risks including: (i) availability of fuel supply through use of hydroelectricity, (ii) availability of hydrological resources and mitigation of transmission constraints through the inclusion of thermal energy near the load center, (iii) providing system reliability during a shortfall of the LIL; and (iv) adherence to Clean Electricity Regulations.

Above all, together, these assets provide the best balance of cost, reliability and environmental responsibility, in line with Hydro's mandate. Hydro's recommended Minimum Investment Required Expansion Plan continues to be the optimal solution for the Island Interconnected System to meet the future demand.

The requested analysis provided herein continues to support Hydro's recommendation for the Minimum Investment Required Expansion Plan as outlined in the 2024 Resource Adequacy Plan and the 2025 Build Application. Hydro continues to recommend the resources and timeline proposed in its 2025 Build Application, with in-service dates for BDE Unit 8 in 2031 and the Avalon CT in 2029.

An unredacted version of question 2 is being provided to the Board on a confidential basis; the parties will be provided with a version in which this information has been redacted. Hydro requests that the Board use the redacted version for posting to its website.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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Q. The Bates White Report identified a possible inconsistency in the modeling of the fuel burn-off issue with respect to the expansion plan scenario data provided by Hydro.[1] Hydro should address and reconcile the potential modeling inconsistency regarding the resource selection identified by Hydro under Scenario 4AEFC.

A. In the Bates White Economic Consulting, LLC ("Bates White") report, Bates White makes the following statement:

> We identified a possible inconsistency in Hydro's reported model results. The estimated cost of the "fuel burn-off" requirement for the Avalon CT is substantial. When the assumed burn-off requirement is removed, the total NPV cost of BDE8 is higher than that of the Avalon CT. However, Hydro's results for Scenario 4AEFC, which excludes the burn-off requirement, still shows BDE 8 selected for a 2031 in-service date and the Avalon CT in 2035. This is counterintuitive and runs contrary to our calculation, which shows the cost of this alternative as $13.7 million *lower* on an NPV basis than for the 4AEFC results provided by Hydro. This does not appear consistent with the expansion model optimizing for the lowest-cost plan.[2]

Under Newfoundland and Labrador Hydro's ("Hydro") Scenario 4AEFC (Fixed Wind Profile, No Batteries, Limit CTs, and No Fuel Burn-Off), the Plexos model has appropriately chosen the least-cost option, which recommends the construction of Bay d'Espoir Unit 8 ("BDE Unit 8") in 2031, taking into consideration the different capacity sizing of the resource alternatives. In the circumstance where there is no fuel burn-off requirement, Bates White's expectation that the model would build the Avalon Combustion Turbine ("Avalon CT") ahead of BDE Unit 8 would be correct, **but only in the scenario where the two resource options had the same firm capacity.** In reality, BDE Unit 8 has approximately 13 MW more firm capacity than the Avalon CT.[3]

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[1] Paragraph (103), pages 50-51.
[2] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025, p. 11.
[3] BDE Unit 8 was modelled with a rated capacity of 154.4 MW, and the Avalon CT was modelled with a rated capacity of 141.6 MW. Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, p. 20, Table 1.

As a result, with no fuel burn-off requirement, if the Avalon CT were to be built first in 2031 as suggested by Bates White, then BDE Unit 8 would be required in 2034 to meet capacity planning criteria, rather than 2035 as Bates White has assumed in their analysis. This one-year advancement of BDE Unit 8 to meet reliability criteria would result in a net present value which is $13 million higher than the least-cost option identified by the Plexos model in Hydro's analysis for this particular scenario.

Q. **a)** Provide three additional capacity expansion model runs for Scenarios 4AEF, 4AEFC, and 4AEFDH. In each run, Hydro should:

i. i. relax the combustion turbine ("CT") constraints and battery energy storage systems ("BESS") prohibition. If there are any methodological differences in updating capital cost assumptions across technologies (for example the methodology for updating BESS capital costs compared to incremental CT capital cost) these differences should be reconciled in the analysis.

ii. ii. relax the constraints around the Avalon CT, including both the 150 MW limit and the 150 MW "blocks" modeled, to allow for smaller, 50 MW blocks, and additions beyond the 150 MW limit.

iii. iii. include BESS resources of 4-hour and 8-hour duration, assuming ELCCs of 60%, using updated capital cost estimates for BESS resources.

A. **a)** For the purpose of this analysis, Newfoundland and Labrador Hydro ("Hydro") ran three additional sensitivity analyses as requested by the Board of Commissioners of Public Utilities ("Board"). Overall, when capital costs were modelled at P50 and P55, for Bay d'Espoir Unit 8 ("BDE Unit 8") and the Avalon Combustion Turbine ("CT") respectively, **the initial least-cost supply options to meet the Minimum Investment requirements results in the same Expansion Plan as Scenario 4AEF (Minimum Investment Required) that was presented in the 2025 Build Application (i.e., BDE Unit 8 in 2031 and the Avalon CT in 2035).**

When capital costs were increased to P85, the model continued to select BDE Unit 8 first in 2031; however, Battery Energy Storage System ("BESS") was selected instead of the Avalon CT in 2035, with additional BESS units added in subsequent years. However, it is important to note that the cost estimate for the BESS and other supply stack alternatives are considered Class 5, compared to Class 3 for the Avalon CT cost estimate.[1] Further, there remain appreciable feasibility concerns surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the Labrador-Island Link ("LIL") bipole. **Hydro's position remains that, given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions should not be included as capacity resources within the 2025 Build Application analysis.**

Please refer to Hydro's response to part a) of question 3 of this proceeding for additional analysis on BESS limitations during a LIL shortfall event.[2]

The results from Hydro's additional capacity expansion model run that incorporates the requested resource options, including BESS and relaxed constraints on CTs, are detailed below as follows:

- Expansion Plan Analysis:
  - o Scenario 4A (Fixed Wind Profile);
  - o Scenario 4AC (Fixed Wind Profile, No Fuel Burn-Off); and
  - o Scenario 4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85).
- Cost Estimates and Modelling Assumptions.
- Expansion Plan Results.
- Conclusion.

<u>Expansion Plan Analysis</u>

Table 1 outlines the three additional Expansion Plan runs completed by Hydro, including a description of each sensitivity for reference.

[1] Association for the Advancement of Cost Engineering ("AACE") Class 3 cost estimates were conducted to support the 2025 Build Application. Whereas the AACE Class 5 estimate is based on conceptual documentation. The accuracy of the AACE Class 5 cost estimate is estimated to be between 50% less to 100% more of the estimated cost.
[2] Hydro is committed to further study of battery effective load carrying capability ("ELCC") to inform the 2026 Resource Adequacy Plan.

Table 1: Expansion Runs From 2025 Build Application

Requested Sensitivity	Description of Scenario
AEF	Fixed wind profile to meet firm energy criteria, removes batteries as a resource option, and limits CT additions to 150 MW in consideration of current diesel fuel supply availability on the Island.
AEFC	A combination of Sensitivities AEF and C to determine the impact of removing forced CT fuel burn-off.
AEFDH	A combination of Sensitivities AEF, D, and H to determine the impact of an increase in costs for both BDE Unit 8 and the Avalon CT, by including the P85 costs for both BDE Unit 8 and the Avalon CT.

In its correspondence dated July 22, 2025,[3] the Board requested the following modifications be made to each of the three additional runs outlined in Table 1:

- Unrestricted CTs (i.e., to allow the model to select more than 141.6 MW);
- Model 47.2 MW CT blocks (e.g., versus 141.6 MW blocks); and
- Allow both 4-hr and 8-hr batteries (i.e., unrestricted BESS).

Following the same naming convention as the analysis completed for the 2025 Build Application, these modified runs are outlined in Table 2. This nomenclature has been used throughout the analysis in this response to maintain consistency with previous analysis in Hydro's 2024 Resource Adequacy Plan and 2025 Build Application proceedings.

Table 2: New Expansion Runs

Modelled Sensitivity	Description of Sensitivity
A	Fixed wind profile to meet firm energy criteria. All other resource options (i.e., BESS and CTs) are included. Other than fixing the wind profile to meet the firm energy criteria, there are no other resource restrictions in the Plexos model.
AC	A combination of Sensitivities A and C to determine the impact of removing forced CT fuel burn-off.
ADH	A combination of Sensitivities A, D, and H to determine the impact of an increase in costs for both BDE Unit 8 and the Avalon CT, by including the P85 costs for both BDE Unit 8 and the Avalon CT.

[3] "Newfoundland and Labrador Hydro - 2025 Capital Budget Supplemental Application -Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine - To Parties – Request to Hydro to Provide Additional Information," Board of Commissioners of Public Utilities, July 22, 2025.

These three additional sensitivities were modelled for Scenario 4 (Minimum Investment Required), which represents the scenario requiring the minimum investment (i.e., the least amount of resource additions) based on a high level of LIL reliability (1% LIL bipole EqFOR[4]) that can reasonably be expected in the long-term, and the lowest load growth (Slow Decarbonization forecast) that can be reasonably anticipated on the Island Interconnected System. This scenario was intended to bookend the Expansion Plan scenarios created in the 2024 Resource Adequacy Plan by identifying the Minimum Investment Required on the Island Interconnected System.

Cost Estimates and Modelling Assumptions

To align with the new sensitivity requests, new cost estimates were developed, which have been provided as Attachments 1 and 2 to this information request.[5] The following resource options were incorporated into the Plexos model:

- 1 x 47.2 MW stand-alone CT project. The cost estimate assumes that no other new CTs are built first.
- 2 x 47.2 MW (94.4 MW total) stand-alone CT project. The cost estimate assumes that no other new CTs are built first.
- 1 x 47.2 MW incremental CT addition. The cost estimate assumes that at least one CT is constructed before this resource option can be selected. This resource has a lower unit cost than the 47.2 MW CT due to sharing some balance of plant with the initial CT build.
- Updated cost estimates for 4-hr and 8-hr batteries were also prepared, and both resource options were included in the additional scenario analysis.
    - An ELCC of 60% was assumed for the 4-hr batteries.
    - An ELCC of 80% was assumed for the 8-hr batteries.

[4] Equivalent Forced Outage Rate ("EqFOR").
[5] Please refer to the Basis of Estimate provided as Attachment 1 of this response for details pertaining to the new cost estimates for CTs. Attachment 2 of this response provides the basis of the cost estimate for BESS resources.

For ease of reference, Table 3 summarizes the resource options considered in the 2025 Build Application analysis and the cost estimates for the new resource options included in the Plexos model in this response, in 2024 CAD dollars.

Table 3: Resource Option Cost Estimates (Expected Case)[6]

				Expected Cost of Firm Capacity ($/kW)		Difference	
Resource Type	Resource	Rated Capacity (MW)	Firm Capacity (MW)	2025 Build Application	Additional Analysis	($/kW)	(%)
Hydro	BDE Unit 8	154.4	154.4	[redacted]	[redacted]	0	0
	CAT Arm Unit 3	68.2	68.2	[redacted]	[redacted]	0	0
	Island Pond	36	36	[redacted]	[redacted]	0	0
	Round Pond	18	18	[redacted]	[redacted]	0	0
	Portland Creek	23	23	[redacted]	[redacted]	0	0
Thermal	3 CTs	141.6	141.6	[redacted]	[redacted]	0	0
	2 CTs	94.4	94.4	[redacted]	[redacted]	n/a	n/a
	1 CT	47.2	47.2	[redacted]	[redacted]	n/a	n/a
	Incremental CT	47.2	47.2	[redacted]	[redacted]	n/a	n/a
Wind	100 MW	100	22	9,727	9,727	0	0
Battery	50 MW 4-hr	50	30	3,805	3,468	-337	-8.9
	50 MW 8-hr	50	40	n/a	4,747	n/a	n/a
Solar	20 MW	20	0	n/a	n/a	n/a	n/a
Proxy Capacity	50 MW	50	50	10,000	10,000	0	0

For ease of reference, Table 4 presents the Authorized Budget (P85) cost estimates used in the 2025 Build Application and the recalculated P85 cost estimates[7] used in response to this question, in 2024 CAD dollars. The ratio of Management Reserve to base cost from the BDE Unit 8 capital cost estimate was used to estimate Management Reserve for all other hydro options. Similarly, the ratio of Management Reserve to base cost from the Avalon CT capital cost estimate was used to estimate Management Reserve for the new CT resource options described herein. Table 4 includes only hydro and thermal resource options, as these were the only resource types for which authorized budgets were estimated; however, while not

[6] Note that year and resource-specific escalation factors are applied to these costs within the Plexos model to reflect expected changes in capital cost over time.
[7] For the purposes of this analysis, the P85 values for both the hydro and thermal options were recalculated as per Bates White Economic Consulting, LLC ("Bates White") suggestion to include escalation and interest during construction in the Management Reserve. Please refer to Hydro's response to question 6 of this proceeding for more information on the calculation of Management Reserve.

shown in the table, all other resource options included in Table 3 were included in the Plexos model.

Table 4: Resource Option Cost Estimates (Authorized Budget (P85))[8]

Resource Type	Resource	Rated Capacity (MW)	Firm Capacity (MW)	Authorized Cost of Firm Capacity ($/kW) 2025 Build Application	Additional Analysis	Difference ($/kW)	(%)
Hydro	BDE Unit 8	154.4	154.4	6,990	7,184	+194	+2.8
	CAT Arm Unit 3	68.2	68.2	9,238	9,496	+258	+2.8
	Island Pond	36	36	30,854	31,713	+859	+2.8
	Round Pond	18	18	37,761	38,813	+1,052	+2.8
	Portland Creek	23	23	31,203	32,073	+870	+2.8
Thermal	3 CTs	141.6	141.6	6,295	6,454	+159	+2.5
	2 CTs	94.4	94.4	n/a	7,131	n/a	n/a
	1 CT	47.2	47.2	n/a	10,550	n/a	n/a
	Incremental CT	47.2	47.2	n/a	8,644	n/a	n/a

Results

Scenario 4 (Minimum Investment Required) includes the 2024 Slow Decarbonization load forecast, assumes a LIL bipole EqFOR of 1%, and a probabilistic planning criteria of 2.8 LOLH.[9] The results of the Expansion Plan sensitivities are summarized in Table 5 and Table 6 and include the resources built, their firm capacity and firm energy contributions, the cumulative number of units of the resource required in each year (green highlighting indicates the addition of one or more units in that year), and the total firm capacity and firm energy corresponding to the Expansion Plan, reported on an annual basis. Table 5 and Table 6 show the results for 2030 through 2040 for a complete picture of the resources required in the simulation period, especially when BESS is selected as a resource option. However, the end of the planning horizon remains 2035, as per the 2025 Build Application, to reflect the industry standard of a ten-year planning horizon. No expansion units are required prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets

[8] Note that year and resource-specific escalation factors are applied to these costs within the Plexos model to reflect expected changes in capital cost over time.
[9] Loss of Load Hours ("LOLH").

through the Bridging Period.[10] The firm capacity added to the system in each year may be more than the requirement due to the size of the units selected as the least-cost resource options. For example, a 50 MW unit might be the least-cost option to fill a 20 MW requirement. Lastly, the net present value ("NPV") is included for each Expansion Plan sensitivity and is provided in Table 7.

Scenario 4A (Fixed Wind Profile)

As demonstrated in Table 5, **Scenario 4A (Fixed Wind Profile) resulted in the same expansion build-out as Scenario 4AEF (Fixed Wind Profile, No Batteries, and Limit CTs) from the 2025 Build Application.**[11] That is, when batteries are included as resource options, CTs can be selected in 47.2 MW increments, and the limitation on the number of CTs that can be built is removed. **The Expansion Plan recommendation does not change from Scenario 4AEF (Fixed Wind Profile, No Batteries, and Limit CTs) as provided in the 2025 Build Application.**[12]

Table 5: Scenario 4A (Fixed Wind Profile)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
CT	141.6	0						1	1	1	1	1	1
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	384	384	384	406	406	406
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

[10] The Bridging Period is defined as the period from the present until 2030, the year in which aging thermal assets are planned to be retired. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

[11] The cost estimates developed by Hydro for BDE Unit 8 and the Avalon CT included escalation costs through the construction period of the two units. A separate escalation factor was applied in the Plexos model to account for a shift in the timing of the project, which resulted in an error that saw the double-application of escalation during construction. All scenarios were re-run with this change to the escalation tables. None of the Expansion Plans were affected by this update. Please refer to Attachment 3 of this response for the updated information previously provided to Bates White.

[12] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 5.2.2.1.1.

The Expansion Plan for Scenario 4A includes BDE Unit 8 in 2031 and the Avalon CT in 2035. To meet the firm energy criteria, 100 MW of wind is required in 2030, corresponding to the same year that Holyrood Thermal Generating Station would be retired. The firm energy requirement escalates to 300 MW of wind in 2031, and further escalates to 400 MW by 2033. The NPV of Scenario 4A is $3.1 billion. **The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 in 2031 and the Avalon CT in 2035.**

Wind is the least-cost energy resource (as opposed to solar or small hydro options) to meet the firm energy requirements of the Island Interconnected System. The fixed wind profile was maintained throughout the remainder of the analysis to ensure that firm energy criteria is being met in each Expansion Plan sensitivity for Scenario 4 (Minimum Investment Required). The firm energy requirement is dependent only on the Island Interconnected System load forecast, and the fixed wind profile is consistent for each load forecast scenario.[13]

Scenario 4AC (Fixed Wind Profile, No Fuel Burn-Off)

At this time, Hydro is assuming that ten days of fuel storage associated with the Avalon CT as a resource option must be burned off annually. Further study is ongoing to assess logistical solutions for fuel in storage, including determining whether unused fuel can be cycled via new contractual agreements or partnerships. The Expansion Model is being forced to burn off the fuel annually as a worst-case scenario to ensure Hydro is fully capturing the associated costs. A sensitivity was included to remove this fuel burn-off requirement; instead, fuel costs are reflective of simulated production requirements that are much lower. The results of Scenario 4AC also resulted in the same Expansion Plan as Scenario 4A presented in Table 5, and Scenario 4AEF from the 2025 Build Application. The NPV of Scenario 4AC is $3.0 billion, approximately $0.1 billion less than Scenario 4A. **The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 in 2031 and the Avalon CT in 2035.**

[13] For more information on firm energy requirements, please refer to "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 4.0.

Scenario 4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85)

This sensitivity included increasing both the Avalon CT capital cost and the BDE Unit 8 capital cost to the Authorized Budget P85 cost[14,15] and is reflected in Table 6. The ratio of Management Reserve to base cost from the BDE Unit 8 capital cost estimate was used to estimate Management Reserve for all other hydro options. Similarly, the ratio of Management Reserve to base cost from the Avalon CT capital cost estimate was used to estimate Management Reserve for the new CT resource options described herein.

Table 6: Scenario 4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
Battery 4-hr 50 MW	30	0						1	2	2	3	4	5
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	272	302	302	354	384	414
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

In this scenario, the model continues to construct BDE Unit 8 in 2031, followed by a 4-hour 50 MW BESS in each of 2035, 2036, 2038, 2039, and 2040, instead of the Avalon CT. **The initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8**, which is expected, given the long economic life of a hydro facility, and relatively lower operational costs, compared to other resource options in Hydro's supply stack. The NPV of Scenario 4ADH is $3.2 billion, approximately $0.1 billion more than Scenario 4A, which has the same Expansion Plan as Scenario 4AEF as provided in the 2025 Build Application.

Based on the analysis Hydro performed as part of the *Reliability and Resource Adequacy ("RRA") Study Review*, BESS are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility concerns surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions were not included as capacity resources in the Minimum Investment Required

[14] *Supra,* f.n. 7.
[15] In all other Scenarios, unless otherwise stated, the P50 capital cost for BDE Unit 8 and the P55 capital cost for the Avalon CT is modeled.

Expansion Plan (i.e., the recommended Expansion Plan). This remains Hydro's position. Additional information can be found in response to PUB-NLH-339 of the *RRA Study Review* proceeding. Hydro is committed to further study of battery ELCC to inform the 2026 Resource Adequacy Plan as outlined in response to PUB-NLH-334. Lastly, please refer to part a) of the response to question 3 of this proceeding for additional analysis pertaining to BESS performance during a LIL shortfall situation.

NPV Comparison

The total Expansion Plan costs presented herein include generation capital costs, fixed and variable O&M[16] costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast.[17] Financing costs associated with new capital spending are excluded. The costs of transmission requirements are also not considered in the NPV comparison; however, these costs were addressed in Section 7.3 of the 2024 Resource Adequacy Plan.[18] The annual costs from the PLEXOS model are translated to a NPV using the weighted average cost of capital to discount future financial impacts to today's value. Because the selected generation expansion units will continue to operate well beyond the modelling horizon (the economic life of the resources considered in this study ranges from 20 to 60 years), the objective function used in the PLEXOS model sums the present values of costs beyond the final modelling horizon year. It is assumed that annualized build costs and operational costs are extended into perpetuity beyond the final year of the modelling horizon, and these are discounted and then summed to arrive at the total NPV cost presented herein.

Table 7 presents the NPV of the above Scenario 4 (Minimum Investment Required) sensitivities, including how the result changed from previous results.[19]

[16] Operations and maintenance ("O&M").
[17] It is likely that there will be market revenue associated with resource options that generate energy that could marginally decrease the NPV of each scenario; however, to avoid counting on a potential market revenue forecast that may not occur, it was removed from this analysis.
[18] Hydro is exploring whether lower-cost alternatives can be implemented to maximize transfer capacity through existing assets, including the implementation of a Remedial Action Scheme and/or Dynamic Line Rating technology as technically equivalent options to the transmission requirements.
[19] Please refer to Attachment 4 of this response for information previously provided to Bates White on June 10, 2025.

Table 7: Expansion Plan Costs (NPV, $ Million)

Scenario (New)	NPV ($ Billion)	Scenario (Previous)[20]	NPV ($ Billion)	Delta
4A (Fixed Wind Profile)	$3.1	4AEF (Fixed Wind Profile, No Batteries, Limit CTs)	$3.1	No Change
4AC (Fixed Wind Profile, No Fuel Burn-Off)	$3.0	4AEFC (Fixed Wind Profile, No Batteries, Limits CTs, No Fuel Burn-Off)	$3.0	No Change
4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85)	$3.2	4AEFDH (Fixed Wind Profile, No Batteries, Limit CTs, Increase Hydro and CT Capital Costs to P85)	$3.3	- $100 Million (3%)

The above results suggest that the NPV cost of building BESS instead of the Avalon CT is slightly less costly when the Avalon CT cost is set to the full authorized cost (P85). However, it is important to note that this analysis is comparing a Class 3 cost estimate for both BDE Unit 8 and the Avalon CT that has gone through both front-end engineering design ("FEED") analysis and includes details supporting the proposed Contingency and Management Reserve to support the build application. That estimate represents a significantly higher level of engineering compared to the Class 5 cost estimate for the BESS and other supply stack alternatives.[21] In addition, as stated previously, there remain appreciable feasibility concerns surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Please refer to the response to part a) of question 3 of this proceeding for additional analysis on BESS performance during a LIL shortfall event.

<u>Conclusion</u>

To conclude, by adding both 4-hr and 8-hr batteries, unrestricting CTs, allowing the Plexos model to build 47.2 MW and 94.4 MW CT options, as well as a cheaper 47.2 MW incremental CT, **results in the same Expansion Plan as Scenario 4AEF (Minimum Investment Required) that was presented in the 2025 Build Application.** The model shows

[20] The updated NPV calculations for the capacity expansion runs provided in Attachment 4 assumed no batteries, restricted CTs, and included the P85 costs for Hydro and CT options as represented in the 2025 Build Application.
[21] *Supra,* f.n. 1.

that the following resources are required under the Minimum Investment Required scenario:

- In-service date of 2031 for BDE Unit 8;
- In-service date of 2035 for Avalon CT;[22] and
- 400 MW of Wind by 2035.

The only scenario where the Expansion Plan changed is for Scenario 4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85), where BESS was selected instead of the Avalon CT; however, the model continued to select BDE Unit 8 first. While BDE Unit 8 had an in-service date of 2031, a 4-hr 50 MW BESS was selected instead of the Avalon CT in 2035, with additional BESS units added in subsequent years. Please refer to Hydro's response to part a) of question 3 of this proceeding for additional analysis on BESS limitations during a LIL shortfall event.[23]

[22] While this satisfies Hydro's probabilistic criteria, it does not satisfy the LIL shortfall scenario and, as a result, Hydro continues to recommend the advancement of a CT as early as possible. Further discussion on the requirement for the CT by 2031 to meet the LIL shortfall criteria, in addition to BDE Unit 8, can be found in "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.
[23] Hydro is committed to further study of battery ELCC to inform the 2026 Resource Adequacy Plan.

Avalon Combustion Turbine

Basis of Estimate – Construction of Stand-Alone (50 MW and 100MW) and Incremental 50 MW CT Projects at Holyrood

NLH Doc. No. HRDCT2-NLH-49100-ES-BOE-0002-01

Comments: This Basis of Estimate presents the basis and methodologies used to estimate the direct costs, indirect costs, escalation and cost of borrowing for different project execution philosophies for the ACT Project.	**Total # of Pages (including Cover):** 15
This document contains confidential and commercially sensitive information. Access to this report and the information contained within is restricted and should only be shared with the written approval of the Manager of Project Controls of Major Projects.	

				Bethany Cutler Digitally signed by Bethany Cutler Date: 2025.08.22 14:05:31 -02'30'	Ryan Cooper Digitally signed by Ryan Cooper Date: 2025.08.22 14:13:29 -02'30'	John Walsh Digitally signed by John Walsh Date: 2025.08.25 13:19:56 -02'30'
B0	22-Aug-2025	Issued for Use	Glenn Whalen	B. Cutler for Tony Scott	Ryan Cooper	John Walsh
Status/Revision	**Date (DD-MMM-YYYY)**	**Reason for Issue**	**Prepared By**	**Project Controls Manager Approval**	**Project Manager Approval**	**Sr Mgr Major Proj & Eng Manager Approval**

These signatures are required to confirm compliance with Major Projects procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

Contents

List of Attachments

Attachment 1: " AACE Estimate Classification Matrix" – AACE International. (August 7, 2020) Recommended Practice 18R-97, Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries.

1.0 Executive Summary

In March of 2025, Hydro submitted a Build Application to the Board of Commissioners of Public Utilities, for approval to proceed with the design and construction of a new Combustion Turbine Power Generation Plant in Holyrood, Newfoundland, with an approximate capacity of 150MW. To aid the PUB's assessment of the Build Application, the PUB has requested that expansion modelling be conducted allowing for smaller, 50 MW CT blocks, and additions beyond the 150 MW limit. For this analysis, Hydro have estimated the costs for the following three resource options:

1. Design and build a stand-alone 50MW Combustion Turbine Power Generation Plant in Holyrood.
2. Design and build a stand-alone 100MW Combustion Turbine Power Generation Plant in Holyrood.
3. Design and build an incremental 50 MW Combustion Turbine to be added to either the 50 MW, 100 MW, or 150 MW CT Combustion Turbine Power Generation Plant in Holyrood.

Table 1 compares the estimated costs of these three new resource options to the estimated cost of executing the 150MW Plant as proposed in the 2025 Build Application. The costs listed in Table 1 include the following:

1. Engineering, Procurement and Construction Management (EPCM)
1. Equipment and Materials
2. Construction and Completions
3. Hydro's Costs
4. Escalation and Interest During Construction
5. Contingency
6. Management Reserve

It is important to note that all costs listed in Table 1 are based on each new project starting at the same time the proposed 150MW Plant was planned to start. Therefore, the escalation costs are based on the time that is required to execute each project, and hence does not include escalation costs associated with delaying the start of each project until a later date in the future. The cost impact associated with executing either project in the future will be reflected in the results of the modelling that will be performed by Hydro's Resource and Production Planning department.

It is also important to note, that unlike the 150MW Plant referenced in the 2025 Build Application, FEED was not completed for any of the new resource options discussed herein. Therefore, the estimated costs for each new option are less accurate, but for the purpose of demonstrating how much greater or lower in cost each option is compared to the others, this is an acceptable estimating methodology.

Table 1: Cost Summaries[1] - New Resource Options vs Proposed 150MW Avalon CT

Cost Description	Estimated Cost to Construct the 150MW Plant	Estimated Cost for the Option to Initially Construct a 50MW Plant	Estimated Cost for the Option to Initially Construct a 100MW Plant	Estimated Cost to Increase Either Option, Incrementally, by 50MW
Base Cost (Direct + Indirect) Estimate Sub-Total	[redacted]	[redacted]	[redacted]	[redacted]
Project Contingency				
Base Estimate (with Contingency) Sub-Total				
Escalation				
Interest During Construction (IDC)				
Planned Budget				
Management Reserve				
Total Cost Estimate (Authorized Budget)				
Additional Escalation Cost[3]				
Additional IDC Cost[3]				
Total Cost Estimate; for inclusion of additional Escalation and IDC costs	**$913,899,159[4]**	**$497,948,057[4]**	**$673,170,215[4]**	**$407,978,113[4]**

[1] All costs referenced herein are expressed in Canadian dollars unless noted otherwise.
[2] Total Cost Estimate (Authorized Budget) as proposed in the 2025 Build Application.
[3] Additional Escalation and IDC cost for spending 100% of the Management Reserve.
[4] It is not standard practice to include Management Reserve in the escalation and IDC calculations because Management Reserve, unlike Contingency, is not meant to be spent. However, Total Cost Estimate values for each option include the potential Escalation and IDC costs that would be incurred if Management Reserve was spent; as suggested in the Bates and White Report dated June 24, 2025.

2.0 Abbreviations, Acronyms and Definitions

Abbreviation/Term	Definition
AACE	Association for the Advancement of Cost Engineering International
ACT or Avalon CT	Avalon Combustion Turbine
BoE	Basis of Estimate
BOP	Balance of Plant – All auxiliary and utility systems that are required to operate a Combustion Turbine, and deliver the power generation to the Newfoundland and Labrador power grid.
CAD	Canadian dollars
Conceptual Estimate	An estimate generally prepared based on very limited Information.
Contingency	An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs.
CT	Combustion Turbine
CT1	Combustion Turbine #1 – Existing Industrial Frame Combustion Turbine that was installed at the Holyrood Thermal Generation Station in 2014.
EPCM	Engineering, Procurement, Construction and Management
Escalation	A provision in costs or prices for uncertain changes in technical, economic, and market conditions over time.
FEED	Front-End Engineering Design, a major part of FEP, includes sufficient field investigations and engineering to establish a contracting strategy and Class 3 cost estimate.
Holyrood TGS	Hydro Thermal Generating Station. A Thermal Generating Power Plant located in Holyrood, Newfoundland and Labrador.
HRDCT2	Combustion Turbine Plant #2 – Proposal for the design and construction of a new Combustion Turbine Power Generation Plant at the Holyrood Thermal Generation Station.
Hydro	Newfoundland and Labrador Hydro
IDC	Interest During Construction. The cost for the use of capital; sometimes referred to as the time value of money.
Major Projects	Regulated projects and programs with an anticipated cost of $50 million or greater under the accountability of the Major Projects Department.
Management Reserve	An amount added to a cost estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated. This may include amounts within the defined scope, but for which management does not want to fund as Contingency, or that cannot be effectively managed using Contingency. Management Reserve, as it applies to the ACT Project, is the difference between the expected 85% underrun cost for the project and the 55% underrun cost for the project.
MW	Megawatt

NLH	Newfoundland and Labrador Hydro
Plant	Combustion Turbine Power Generation Plant
PUB	Public Utilities Board - Board of Commissioners of Public Utilities
QRA	Quantitative Risk Assessment
Risk	An uncertain event or condition that, if it occurs, has a positive or negative effect on a project's objectives.
USD	United States dollars

3.0 Reference Documents

The following is a list of documents that either are referenced in this Basis of Estimate document or are relevant to the subject matter contained within.

Title	Reference	Revision	Document Location
Avalon Combustion Turbine Basis of Estimate	HRDCT2-NLH-49100-EP-EST-0001-01	B0	*
150 MW Combustion Turbine FEED Study Basis of Estimate	HRDCT2-HAT-49100-EP-EST-0001-01	B0	*
Parametric QRA Report	HRDCT2-HAT-49100-PC-EST-0001-01	B1	*
Capital Cost Estimate	HRDCT2-HAT-49100-EP-EST-0004-01	B1	*
Project Control Schedule and Basis	HRDCT2-NLH-49100-PC-BOS -0001-01	B0	*
2025 Build Application - Bay d'Espoir Unit 8 and Avalon Combustion Turbine	Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Confidential	Dated March 21, 2025	*
ACT Estimate	Excel Native File	Rev. 0	SharePoint

* Document was formally submitted to Hydro as a stand-alone document therefore it is not contained within this BoE as an attachment.

4.0 Introduction

In response to the recommendations noted in the 2024 Resource Adequacy Plan, Hydro submitted a Build Application to the PUB to build a new 150MW Combustion Turbine Power Generation Plant near the existing Thermal Generation Station in Holyrood, Newfoundland. The PUB is currently in the process of evaluating and assessing the information that was provided with the 2025 Build Application. In order to assess whether the proposed build is the best value solution, the PUB requested that expansion modelling be conducted allowing for smaller, 50 MW CT blocks, and additions beyond the 150 MW limit. For this analysis, Hydro have estimated the costs for three new resource options listed in Section 1.0, and these are the basis for the project cost estimates discussed herein.

Throughout the remainder of this BoE, the word “Plant” will mean “Combustion Turbine Power Generation Plant”.

5.0 Purpose

The purpose of this BoE is to describe the basis and the estimating methodologies that were used to estimate the cost of designing and constructing the three CT projects listed in Section 1.0.

6.0 Project Scope

The project scope for the initial construction of a 50MW Plant is similar to the project scope for the 150MW Plant. The only differences being:

1. The main powerhouse will be sized for one 50MW CT, as oppose to three CT’s.
2. The BOP sizing is based on supporting one 50MW CT.

The cost estimate referenced herein, for the initial build of a 50MW Plant, includes costs for the engineering, procurement, construction and commissioning of all works associated with the Project, including but not limited to:

1. Standalone nominal 50MW CT generating unit, including all necessary auxiliary systems and controls equipment.
2. A dedicated switchyard connection with 13.8 kV/230 kV transformer and standard terminal structures and facilities for connecting 230 kV transmission lines and standard 600 V and 120 V station service utilized for auxiliaries and building services.
3. Fuel storage and supply infrastructure, with 10 days of on-site fuel storage for a 50MW CT. Fuel deliveries will be via road truck, but a new line between the new CT Plant and the existing Jetty is also included for a future option to supply fuel from the marine jetty. Note that the refurbishment or replacement of the existing Jetty in not included in the scope of work for this project, hence the associated costs are excluded.

4. Station Services for the new plant and the existing Combustion Turbine Power Generation Plant (CT1) at the Holyrood TGS site.
5. Black Start Generator.
6. Site Retaining Wall.
7. Relocation of Newfoundland Power Lines.
8. Connection to the TL218 main transmission line.
9. Spare Transformer.

The project scope for the initial build of the 100MW Plant is similar to the initial build of a 50MW Plant. The differences being the Powerhouse for the 100MW Plant will house two 50MW CT's, versus one 50MW CT, and the BOP sizing will be designed for a 100MW Plant.

Regardless of the initial plant being 50MW, 100MW, or 150MW, the work listed below must be executed as part of the initial project execution, but will not be required to increase the capacity of any plant in 50MW increments. Hence, the work scopes listed below are the only differences between the initial build of a 50MW Plant and increasing the plants capacity in 50MW increments.

1. Station Services for the new plant(s) described herein and the existing Holyrood Combustion Turbine Power Generation Plant (Also referred to as CT1) at the Holyrood TGS site.
2. Black Start Generator.
3. Purchase of a spare transformer.
4. Jetty Line
5. Site Retaining Wall
6. Relocation of Newfoundland Power Lines
7. Connection to the TL218 main transmission line.

It is assumed that each time a new 50MW CT is added to increase the plants capacity, the following infrastructure and modifications are required:

1. New powerhouse.
2. New fuel storage tanks.
3. New raw water storage tank.
4. Expansion of Raw Water Pump House.
5. Destruct existing Quarry Brook supply intake to Raw Water Pump House, and upgrade to larger intake for increased capacity.
6. Associated civil works for the above infrastructure, and
7. Remaining BOP to support a stand alone 50MW CT.

7.0 Estimate Methodology

The cost estimates for each resource option were derived from the cost estimate file for the approximate 150MW Plant, that was submitted with the 2025 Build Application (Avalon CT). The quantities of materials, equipment, labour and third-party services listed in the Class 3 cost estimate, that was submitted with the 2025 Build Application, were adjusted for the smaller plant sizes discussed herein; the respective unit dollar rates for materials, labour, etc. remained the same.

Even though each new cost estimate was derived from the Class 3 cost estimate for the 150MW Plant, the estimates cannot be considered to have the same accuracy. Based on the estimator's experience, the cost estimates can be considered a Class 4. In order to achieve a Class 3 level of accuracy, a new FEED study for each option would have to be completed, and the magnitude of contingency and management reserve would have to be qualified and quantified by completing a Quantitative Risk Assessment, and processing the resulting data with a Monte Carlo Simulation.

7.1 Indirect Costs

In the cost estimate file, for the proposed 150MW Plant that is referenced in the 2025 Build Application, indirect costs were calculated two ways. Indirects were calculated as a percentage of direct costs, or are a function of the planned project duration. Therefore, indirects that are calculated as a percentage of directs costs, were adjusted automatically when the quantities of direct costs were changed. To estimate the indirect costs that are dependent on project duration, Hydro's project planner evaluated the schedule for the 150MW Plant and determined the order of magnitude relative changes to the ACT schedule, included with the Build Application, were as follows:

1. The initial construction of a 50MW Plant could be completed approximately 150 days earlier than the initial design and build of a 150MW Plant.
2. The initial construction of a 100MW Plant could be completed approximately 75 days earlier than the initial design and build of a 150MW Plant.
3. Each incremental 50MW increase in the plant capacity could be completed approximately 150 days earlier than the initial design and build of a 150MW Plant.

7.1.1 Insurance

The reduction in the cost of insurance for each option was prorated against the reduction in the direct costs.

7.1.2 FEED

The FEED cost that was incurred for the ACT Project is included in the Total Cost Estimate (Authorized Budget) value referenced in Table 1 for the 150MW Plant Project. The same FEED costs are also included in the cost estimates for each of the new resource options, because another FEED would have to be performed for each new project, due to the changes in plant design, such as interface changes, utility sizing, etc.

7.2 Escalation and IDC

The same methodology that was used to estimate the escalation and IDC costs for the 150MW Plant, was used to estimate the escalation and IDC costs for each new project discussed herein this BoE. As recommended in the Bates and White report, dated June 24, 2025, the additional escalation and IDC costs for expending the Management Reserve were estimated, and are listed in Table 1. However, the Planned Budget estimates referenced in Table 1 does not include the additional escalation and IDC costs that could be potentially incurred due to spending the Management Reserve.

The cost estimates completed for each new project are presented in 2024 dollars. This means the estimated costs are based on the planned start date for each project being the same as the planned start date for the proposed 150MW Plant. Hence, the escalation costs referenced in this BoE are due to the duration of time that is required to execute each project, and does not include cost escalations resulting from delaying the project start date. The cost impacts due to delaying the start of any project will be reflected in the results of the Plexos modelling that will be performed by Hydro's Resource and Production Planning department, and therefore is excluded from the estimated costs presented herein this BoE.

8.0 Planning Basis

Refer to Section 7.1.

8.1 Committed and Planned Spend Profiles

The annual committed and planned spend profiles for each of the new resource options were derived from the weighting of annual committed and planned spend profiles for the 150MW Plant.

9.0 Cost Basis

The cost basis for each of the cost estimates discussed herein are the same as the cost basis for the 150MW Plant presented in the Build Application; units rates remained the same for materials, equipment, labour, etc., and the planned start date for the new projects matched the planned start date for the approximate 150MW Plant.

9.1 Exchange Rates

All costs referenced herein this document are expressed in Canadian dollars. At the time the cost estimate for the 150MW Plant was completed, [redacted] and [redacted]. For each new cost estimate, these rates were not changed. The benefit of keeping the exchange rates the same, permits a more direct comparison of costs with the cost estimate of the approximate 150MW Plant.

10.0 Allowances

The allowances for material wastage, labour productivity, etc. were percentages of direct costs, in the cost estimate for the proposed 150MW Plant. Hence, since the cost estimates for the new projects were derived from the original cost estimate file, the same percentages were applied to the estimated direct costs for each resource option.

11.0 Contingency

The contingency in the cost estimate for the proposed 150MW Plant equated to [redacted] of the base cost estimate value. This same percentage was applied to the estimated base cost for each new resource option. Hydro chose to not change the contingency allowance for two reasons:

1. Contingency can only be qualified and quantified with a quantitative risk assessment, and the resulting Quantitative Risk Assessment data being processed using a statistical model such as a Monte Carlo Simulation.
2. It permits a more direct comparison of costs with the cost estimate of the originally proposed 150MW Plant.

12.0 Management Reserve

The Management Reserve in the cost estimate for the proposed 150MW Plant equated to [redacted] of the base cost estimate value. This same percentage was applied to the estimated base cost value for each new resource option. Hydro chose to not change the management reserve for the same reasons the contingency percentage was not changed (see Section 11.0).

13.0 Estimate Classification

The expected accuracy of the cost estimates for the new resource options suggests the cost estimates could be deemed Class 4 according to AACE guideline 18R-97. A copy of the estimate classification table that is found in 18R-97 is contained in Attachment A.

14.0 Assumptions and Exclusions

The same assumptions and exclusions that were noted in the basis of estimate for the construction of the proposed 150MW Plant remain the same for each of the new resource options discussed herein. However, unlike the 150MW Plant referenced in the 2025 Build Application, it is important to note FEED was not completed for any of the new resource options. Therefore, the estimated costs for each new option are less accurate, and are considered conceptual cost estimates. Conceptual cost estimates are acceptable for the purpose of demonstrating which options are greater or lower in cost, and require less manpower and money to make the determination.

15.0 Risks and Opportunities

The same risks and opportunities that existed for the construction of the 150MW Plant remain the same for each of the new resource option discussed herein.

16.0 Estimating Team

Each cost estimate was completed by Hydro's Senior Cost Estimator for Major Projects.

17.0 Conclusion

The estimating norms, and percentages for contingency, management reserve, currency exchange, etc., that were used to estimate the total installed cost for the 150MW Plant were also used to estimate the total installed cost for each new resource option. Hence, the cost differences between the new resource options and the current proposal to build a 150MW Plant (the Avalon CT), is due to the change in the size of the plant as well as whether or not the project is stand-alone or incremental to a previously constructed CT. It is worth noting that it is more likely the contingency and management reserve allowances for the new resource options would be greater than what is listed in this BoE because the cost estimates are less accurate. As well, the estimated escalation costs for increasing the plant capacity in 50MW increments would also be greater because the associated work will be executed at a later date. Hence, the estimated costs provided herein for the new project options should be considered lowest possible cost. Any adjustment in the estimated costs due to when the 50MW increases are assumed to be implemented will be reflected in the results of the modelling that is performed by Hydro's Resource and Production Planning department.

The total potential plant capacity of the site will depend on the capacity of the original plant constructed. If a 50 MW Plant is constructed first, the total future plant capacity would be limited to 150MW because the footprint of the site would start encroaching on the neighboring access road, Quarry Brook or the main transmission lines on the opposite side. In the case of 100MW Plant being constructed first, the plant capacity would likely max out at 200 to 250MW, before the plant footprint starts to encroach on existing infrastructure. The currently proposed plan for building the 150MW Plant would allow Hydro to increase the future plant capacity to somewhere in the range of 300MW to 350MW.

Attachment A – AACE Estimate Classification Matrix

AACE Estimate Class	Primary Characteristic Maturity Level of Project Definition (Expressed as % of complete definition)	Secondary Characteristic End Usage (Purpose of estimate)	Methodology (Estimating method)	Expected Accuracy Range (Variation low / high ranges in 80% confidence interval)
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgement, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	**10% to 40%**	**Budget authorization or control**	**Semi-detailed unit costs with assembly level line items**	**L: -10% to -20% H: +10% to +30%**
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

MEMO

Date: September 03, 2025

To: Samantha Tobin, Senior Manager, Resource & Production Planning

From: Doug Maloney, Senior Estimator, Major Projects and Asset Management

Copy: John Walsh, Director, Major Projects and Asset Management

Tony Scott, Project Controls Manager, Major Projects and Asset Management

Marc Cullen, Program Manager, Major Projects and Asset Management

Crystal O'Dea, Project Manager, Major Projects and Asset Management

Subject: Battery Energy Storage System (BESS) Cost Escalation and Adjustment

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This memo describes the methodology and results of an update to a cost estimate for a 50MW 4-hour BESS, and an estimate for a 50MW 8-hour BESS, consisting of an escalation from 2023 to 2024 and also considering potential technology improvements and cost reductions.

Background

Wood Canada Limited (Wood) issued a BESS Project Preliminary Cost Estimate in Sept 2023, which included an estimate for a 50MW 4-hour BESS. (258257-0000-DF00-STY-0001 BESS Project Preliminary Cost Estimate)

In July 2025, NLH Resource and Production Planning requested an update of this estimate, to escalate costs from 2023 to 2024, and also to consider possible cost reductions due to improved BESS technology. An estimate for a 50MW 8-hour BESS was also requested for comparative purposes.

Methodology

The methodology used for the preparation of the BESS estimates included the following:

- Review of Wood base cost estimate
- Escalation of costs (other than BESS Area) from 2023 to 2024 using Hydro's July 2025 Corporate Assumptions.
- Review of available information on cost forecasts for BESS
- Application of cost reduction factor to BESS Area costs
- Scaling from 4-hour to 8-hour BESS as per factor provided by Wood

Assumptions / Information Sources

In conducting this analysis, the following assumptions and information sources were used:

- Escalation – the sub-project types for escalation modelling were assumed as shown in Table 1:

DESCRIPTION	*SUB-PROJECT TYPE (for Escalation Model)*
Engineering and Permitting	[redacted]
BESS Area	[redacted]
Terminal Station Upgrades (69 kV)	[redacted]
Owners Cost [redacted]	[redacted]
Contingency [redacted]	[redacted]

Table 1: Assumed Sub-Project Types for Escalation Modelling

- Cost reduction factor due to potential technology improvements:

  The factor was developed from information at the National Renewable Energy Lab website https://atb.nrel.gov/electricity/2024/data

  The Moderate Case for Utility-Scale Battery Storage was taken as the basis, with the Overnight Capital Cost for 2024 over 2023 resulting in a factor of 0.928.

- Scaling from the 4-hour to 8-hour case:

  A factor of 1.9 was applied to the BESS Area cost, as per information provided in the Wood cost estimate report. Engineering and Terminal Station costs were unadjusted, also per the Wood cost estimate report.

- Estimate Class:

  This estimate is considered Class 5, which aligns with the original Wood estimate.

Results

Results of the BESS estimate update are shown in Table 2.

DESCRIPTION	SUB-PROJECT TYPE (for Escalation Model)	50MW 4-hour BESS Base Cost 2023 $CAD (1)	Allowance for Reduction in BESS Cost (2)	50MW 4-hour BESS Adjusted Base Cost 2024 $CAD (3)	4-hour to 8-hour Scaling Factor (4)	50MW 8-hour BESS Base Cost 2024 $CAD
Engineering and Permitting	[redacted]	$ [redacted]		$ [redacted]	1	$ [redacted]
BESS Area	[redacted]	$ [redacted]	0.928	$ [redacted]	1.9	$ [redacted]
Terminal Station Upgrades (69 kV)	[redacted]	$ [redacted]		$ [redacted]	1	$ [redacted]
Owners Cost [redacted]	[redacted]	$ [redacted]		$ [redacted]		$ [redacted]
Contingency [redacted]	[redacted]	$ [redacted]		$ [redacted]		$ [redacted]
		$ 111,044,157		**$ 104,025,641**		**$ 189,875,431**

(1) Source: 2023-09-29_NLH_RRA Study_BESS Study
The total estimated cost is presented in 2023 dollars and does not include escalation, land costs, transmission upgrades, or any additional project costs that may be required.

(2) Source: National Renewable Energy Lab
https://atb.nrel.gov/electricity/2024/data
Utility-Scale Battery Storage - 4Hr, Moderate Case
0.928 is the Overnight Capital Cost factor for 2024 over 2023.

(3) All items other than BESS Area are escalated using Hydro's July 2025 Corporate Assumptions.

(4) Page 20/116 of 2023-09-29_NLH_RRA Study_BESS Study

Table 2: BESS Estimate Update

Q. **Reference: (Session 4)**

Please provide the NPV/DCF annuity model for both BDE 8 and the Avalon CT that were used to determine the levelized cost of these resources used in NLH’s models.

A. The levelized cost of resources is calculated by the Plexos model using capital costs, escalation factors, the economic life of the unit, and the discount rate. Please see the attached for a re-creation of the calculation that is performed by Plexos for Bay D’Espoir Unit 8 and the Avalon CT.

	BDE 8	Avalon CT	
Discount Rate	[redacted]		
Build Cost			$/kW
Capacity	154.4	141.6	MW
Economic Life	60	35	years
Annuity Factor	16.4	14.7	

Annualized Build Cost

Year Built	2	3
2030	[redacted]	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		

YEAR	Hydraulic Plant Escalation	CT Escalation
2024	1	1
2025	[redacted]	
2026		
2027		
2028		
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2031		
2032		
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Capital Cost Comparison - 2025 Build Application to 2024 Resource Adequacy Plan

Expansion Unit Capital Cost ($/kw) [1,2]

Unit	2024 RAP	2025 BA	2025 BA P85	2025 BA with ITC Tax Credits
Bay D'Espoir Unit 8	3345	[redacted]	6990	5142
Avalon CT	3205	[redacted]	6295	
Hydro - CAT - Unit 3	4662	[redacted]	9238	6796
Hydro - Island Pond	15570	[redacted]	30854	22698
Hydro - Portland Creek	15746	[redacted]	31203	22956
Hydro - Round Pond	19055	[redacted]	37761	27780
Proxy Capacity Resource	10000	10000		
Wind - 100 MW	2082	[redacted]		

[1] Costs are in 2023 dollars for the 2024 RAP and 2024 dollars for the 2025 Build Application. Costs are escalated on an annual basis based on Hydro's Corporate Assumptions.

[2] For all expansion options in the 2024 RAP and the Proxy Capacity Resource and Wind in the 2025 Build Application costs are evenly distributed over the build horizon, so that Plexos accounts for interest during construction. In all other options interest during construction has been calculated outside of Plexos and included in the capital cost estimate.

Q. **b)** Should either of these capacity expansion model runs result in CT capacity additions above 150 MW, provide additional information as to the fuel supply issue, including a discussion of the marine terminal option.

A. **b)** As demonstrated in part a) of this response, neither capacity expansion model run resulted in a combustion turbine ("CT") capacity requirement above approximately 150 MW. There are currently no identified issues with fuel supply for the existing Holyrood CT facility and the proposed 150 MW facility; however, to mitigate any potential issues with fuel availability that may arise in the future, Newfoundland and Labrador Hydro ("Hydro") is continuing to study storage options. Hydro plans to leverage an external expression of interest ("EOI") to explore potential partnerships that may help mitigate fuel risks. In addition to this planned EOI, Hydro is currently completing a concept design to explore optimization of fuel facility integration between the existing and proposed fuel system.[1]

While not a near-term requirement, a marine terminal at the site of the Avalon CT, along with the associated commercial supply agreements, was identified as a future option to further ensure the long-term fuel security for the existing, proposed, and any future CTs. Without confirmed expansion of fuel supply investments on the Island, Hydro would not have a reliable supply of fuel that additional CTs, beyond the 150 MW Avalon CT proposed in the 2025 Build Application, would require to run reliably. This is a primary consideration for the 2026 Resource Adequacy Plan and future resource planning.

As discussed during Technical Conference #2,[2] Hydro has been evaluating the upgrade or potential replacement of the Holyrood Marine Terminal to alleviate long-term fuel security. In January 2025, Artelia Canada Inc. ("Artelia") was awarded a contract to complete an initial concept design, including a condition assessment of the existing marine jetty and provide a report outlining the inspection findings, an Advancement of Cost Engineering

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[1] Hydro will provide an update on fuel supply in its semi-annual report to the Board and parties in the fourth quarter of 2025.
[2] "2024 Resource Adequacy Plan – Technical Conference #2 – Issue #4: Resource Supply Options," Newfoundland and Labrador Hydro, October 2, 2024.

("AACE") Class 4 cost estimate and a recommendation to either refurbish or replace. In its report, Artelia has recommended a refurbishment of the existing jetty to extend the service life in parallel with the planned life of the new CT facility. Hydro is reviewing the report; however, should Hydro decide to proceed with a project, additional work is required to produce front-end engineering design ("FEED") deliverables and an AACE Class 3 estimate for inclusion in a capital application.

As outlined in the CT Feasibility Study, Hydro believes there is sufficient fuel available for the planned 150 MW Avalon CT[3] Should the 2026 Reliability and Resource Adequacy Study analysis indicate the need for additional CTs, or the outcome of the planned EOI indicate that a marine terminal would be required, Hydro would consider the advancement of the project to FEED at that time.[4] Hydro will provide an update in its semi-annual report to the Board of Commissioners of Public Utilities and parties in the fourth quarter of 2025.

[3] "Newfoundland and Labrador Hydro Conception Design Report – Final Report," Hatch Ltd., September 28, 2023.
[4] As outlined in Hydro's response to question 11 of this proceeding, as is the practice with FEED documentation, applicable FEED documentation will be filed with a future capital application for Marine Terminal Station, if necessary, and not stand-alone reporting.

Q. Provide three additional LIL Shortfall Analysis runs to address BESS resources, potential hydrological resource constraints at Bay d'Espoir and the life extension of Hydro's thermal generation.

a) One LIL Shortfall Analysis run should be conducted using BESS resources that are selected as part of expansion plans identified in the additional capacity expansion model run associated with Scenario 4AEF, identified in (2)(a) above. If no BESS resources are selected in that model run, this additional LIL Shortfall Analysis run would be unnecessary.

A. **a)** For purposes of this analysis, Newfoundland and Labrador Hydro ("Hydro") conducted the additional shortfall analysis for the applicable Expansion Plans created for question 2 of this proceeding, as requested by the Board of Commissioners of Public Utilities ("Board"). In addition, as the shortfall analysis was conducted with an in-service date for Battery Energy Storage System ("BESS") technology after Hydro's reference year of 2032, Hydro also performed further shortfall analysis whereby the BESS technology was advanced into 2031, like the Avalon Combustion Turbine ("CT") in the 2025 Build Application. This demonstrates the comparative impact of the CT versus BESS technology on the amount of unserved energy on the system in a Labrador-Island Link ("LIL") shortfall scenario.

Hydro ran the latter analysis using two combinations of BESS resources: a single 50 MW battery ("Combination A") and five 50 MW batteries[1] ("Combination B"). The analysis showed that the effectiveness of BESS decreases as more BESS capacity is added. This indicates that batteries are effective when there is sufficient capacity to fully charge them, but their effectiveness is limited by the amount of surplus capacity available to charge the batteries in off-peak hours.

Overall, Hydro's analysis demonstrated that **under average conditions, the system can expect to see more and deeper outages with BESS compared to the Avalon CT**, with an

[1] On a firm capacity basis this would be comparable to advancing the 141.6 MW CT to 2031.

average of 8 more outage hours, 1.1 GWh of additional unserved energy, and a peak shortfall of 49 MW greater.

Under severe conditions, the system can expect to see an average of 34 more outage hours, 4.0 GWh of additional unserved energy, and a peak shortfall of 48 MW greater. **This clearly demonstrates that BESS would be less effective than the Avalon CT in a shortfall scenario.**

The results from Hydro's additional LIL shortfall analysis are detailed below.

<u>Expansion Plan Analysis</u>

Hydro conducted three additional Expansion Plans in response to part a) of question 2.

- Scenario 4A (Fixed Wind Profile);
- Scenario 4AC (Fixed Wind Profile, No Fuel Burn-Off); and
- Scenario 4ADH (Fixed Wind Profile, Increase Hydro and CT Capital Costs to P85).

For reference, a description of the Expansion Plan sensitivities modeled are summarized in Table 1.

Table 1: Expansion Plan Sensitivities

Modelled Sensitivity	Description of Sensitivity
4A	Fixed wind profile to meet firm energy criteria. All other resource options (i.e., BESS and CTs) are included. Other than fixing the wind profile to meet the firm energy criteria, there are no other resource restrictions in the Plexos model.
4AC	A combination of Sensitivities A and C to determine the impact of removing forced CT fuel burn-off.
4ADH	A combination of Sensitivities A, D, and H to determine the impact of an increase in costs for both Bay d'Espoir Unit 8 ("BDE Unit 8") and the Avalon CT, by including the P85 costs for both BDE Unit 8 and the Avalon CT.

Two of the three scenarios, 4A and 4AC, had the same outputs as Scenario 4AEF (Fixed Wind Profile, No Batteries, Limit CTs) from the 2025 Build Application, which did not select BESS as a resource option; therefore, there is no change to the LIL Shortfall Analysis results that was provided in the 2025 Build Application.[2]

[2] Represented as Combination 1 in "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.1.

As outlined in Hydro's response to part a) of question 2 of this proceeding, Scenario 4ADH identified a 4-hour 50 MW BESS as the least cost supply addition in 2035 in place of the Avalon CT. In this scenario, the model continues to construct BDE Unit 8 in 2031. The Expansion Plan recommendations for Scenario 4ADH would be the same as Scenario 4AEF in the 2032 reference year; therefore, the results of the shortfall analysis for Scenario 4ADH would also be the same as the shortfall analysis for Scenario 4AEF, as BESS is not chosen to be required by the 2032 reference year.[3]

For reference, the estimated unserved energy during the peak day of the 2032 reference year for Scenario 4AEF can be seen in Chart 1.

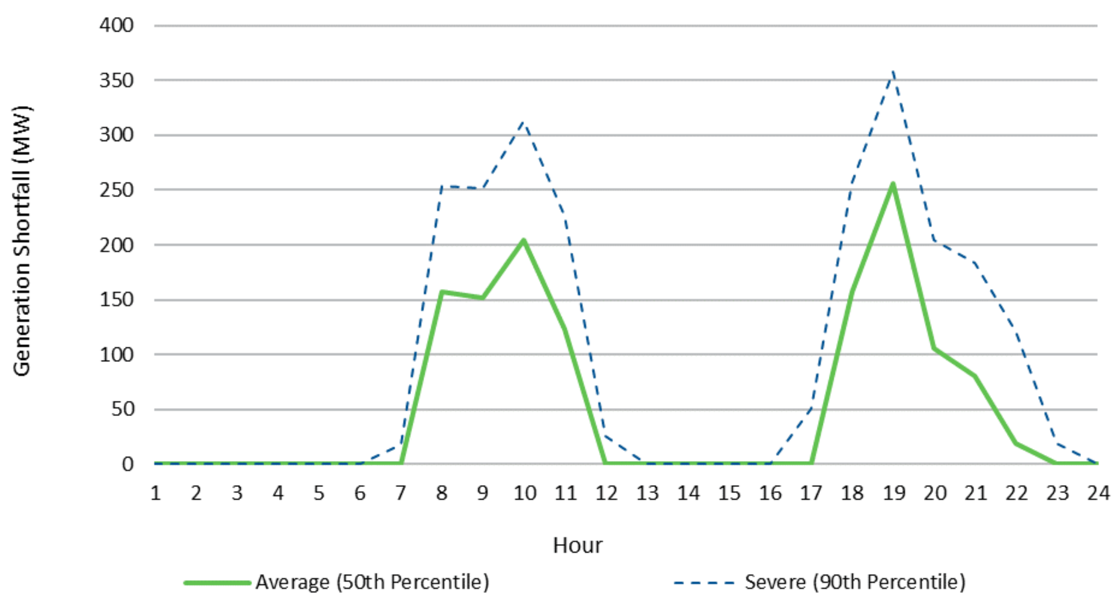

Chart 1: Shortfall on Peak Day (Slow Decarbonization Load, Scenario 4AEF (Fixed Wind Profile, No Batteries, Limit CTs) Expansion Plan)[4]

It should be noted that neither scenario presented in part a) of question 2 of this proceeding, nor Scenario 4AEF, meets all the Island Interconnected System resource planning criteria.[5] The addition of BDE Unit 8 only, in combination with retiring Hydro's

[3] *Supra,* f.n. 2.
[4] *Supra,* f.n. 2.
[5] For information on Hydro's resource planning criteria, please refer to "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 1.0.

aging thermal assets, is insufficient to mitigate a supply shortfall of less than 100 MW,[6] and therefore is in violation of the Shortfall Criteria.

As identified in the 2024 Resource Adequacy Plan and confirmed in the 2025 Build Application, Scenario 4AEF was not sufficient to mitigate supply shortfall to within a manageable level in the case of a LIL shortfall event.[7] **Therefore, Hydro continues to recommend advancing the Avalon CT from 2035 to 2031, in order to ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a manageable level.** This is referred to as Scenario 4AEF(ADV) and is the recommended Minimum Investment Required Expansion Plan.[8] The estimated unserved energy during the peak day of the 2032 reference year for Scenario 4AEF(ADV) (Minimum Investment Required) can be seen in Chart 2 and is summarized in Table 2 and Table 3.

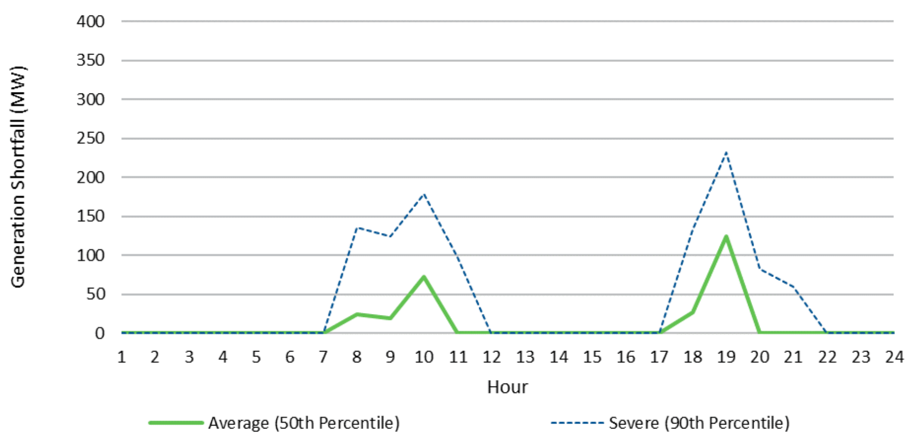

Chart 2: Shortfall on Peak Day (Slow Decarbonization Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)[9]

Table 2 and Table 3 illustrate the comparison of the scenarios under the Average and Severe conditions, respectively.

[6] Newfoundland Power Inc. was able to rotate 100 MW during the 2014 loss-of-load event.
[7] The loss of the LIL bipole is considered a high-consequence event impacting the Island Interconnected System. While it does not have specified planning criteria, planning to mitigate the consequences of a prolonged LIL outage is essential, and Hydro continues to evaluate the reliability implications of an extended LIL outage as part of the resource planning process.
[8] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.2.
[9] Represented as Combination 2 in "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.2.

Table 2: Comparison of Shortfall Statistics Under Average Case[10]

Load Scenario	Slow Decarbonization	Slow Decarbonization
Expansion Plan Scenario	4AEF; 4A; 4AC; 4ADH	4AEF(ADV)
Hours of Shortfall	142	24
Total Energy Shortfall (GWh)	10	1
Peak Shortfall (MW)	256	124
% of Time Shortfall > 100 MW	4%	0.1%

Table 3: Comparison of Shortfall Statistics Under Severe Case[11]

Load Scenario	Slow Decarbonization	Slow Decarbonization
Expansion Plan Scenario	4AEF; 4A; 4AC; 4ADH	4AEF(ADV)
Hours of Shortfall	351	102
Total Energy Shortfall (GWh)	35	7
Peak Shortfall (MW)	358	232
% of Time Shortfall > 100 MW	14%	3%

To ensure that the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a previously demonstrated level in the case of a LIL shortfall event, advancing the Avalon CT from 2035 to 2031 is required, as demonstrated in Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan.

<u>Additional Analysis for Information</u>

Using the same logic as the recommendation to advance the Avalon CT, Hydro believed that it would be beneficial for information purposes to conduct a LIL shortfall analysis where BESS are advanced to 2031 instead of the recommended Avalon CT. In this comparison, Scenario 4ADH was used as the basis for comparison, as this is the only scenario in response to part a) of question 2 of this proceeding where BESS were selected by the model.

For this analysis, two shortfall runs were completed:

- **Combination A:** Slow Decarbonization load forecast and Scenario 4ADH, and a single 50 MW 4-hour BESS advanced from 2035 to 2031.

[10] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.3.
[11] *Supra,* f.n. 10.

- **Combination B:** Slow Decarbonization load forecast and Scenario 4ADH, and five 50 MW 4-hour BESS advanced from 2040 to 2031.[12]

Combination A Results

Combination A assumes the Slow Decarbonization load forecast with Scenario 4ADH with the single 50 MW 4-hour BESS advanced from 2035 to 2031. This combination provides an assessment of the supply shortfall that could be expected if the BESS resource option were advanced by a few years.

As Chart 3 demonstrates, under the Average Case (green line), unserved energy would be expected to occur in 105 hours over the six-week period, representing 6.5 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 212 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 315 MW with 270 hours of unserved energy over the period, representing 24 GWh of energy shortfall.

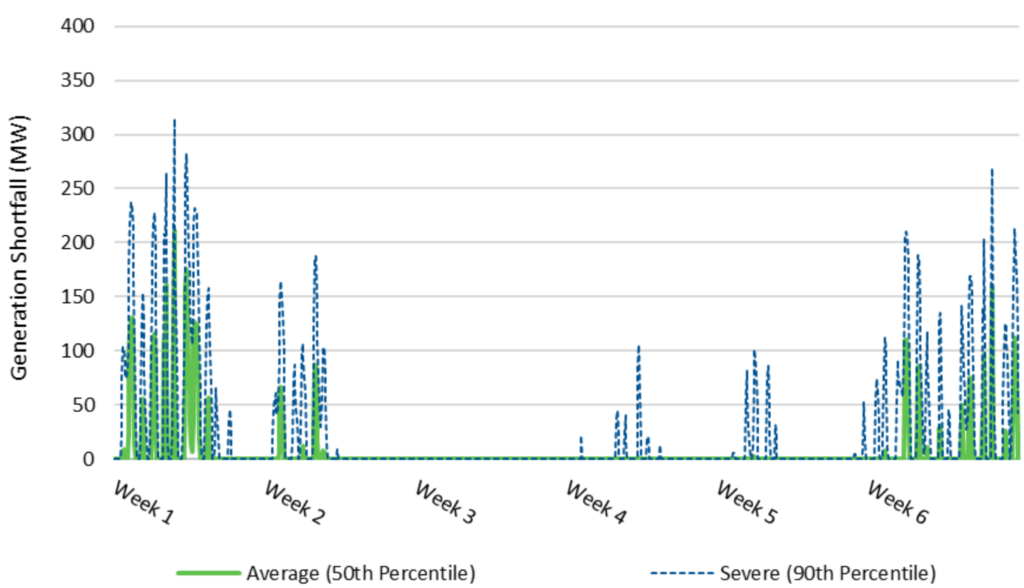

Chart 3: Shortfall over Six Weeks (Combination A: Slow Decarbonization Case Load, Scenario 4ADH and 50 MW BESS Advanced to 2031)

The estimated unserved energy during the peak day of the 2032 reference year for Combination A**:** Slow Decarbonization load forecast and Scenario 4ADH with 50 MW of BESS capacity advanced to 2031 can be seen in Chart 4.

[12] On a firm capacity basis this would be comparable to advancing the 141.6 MW CT to 2031.

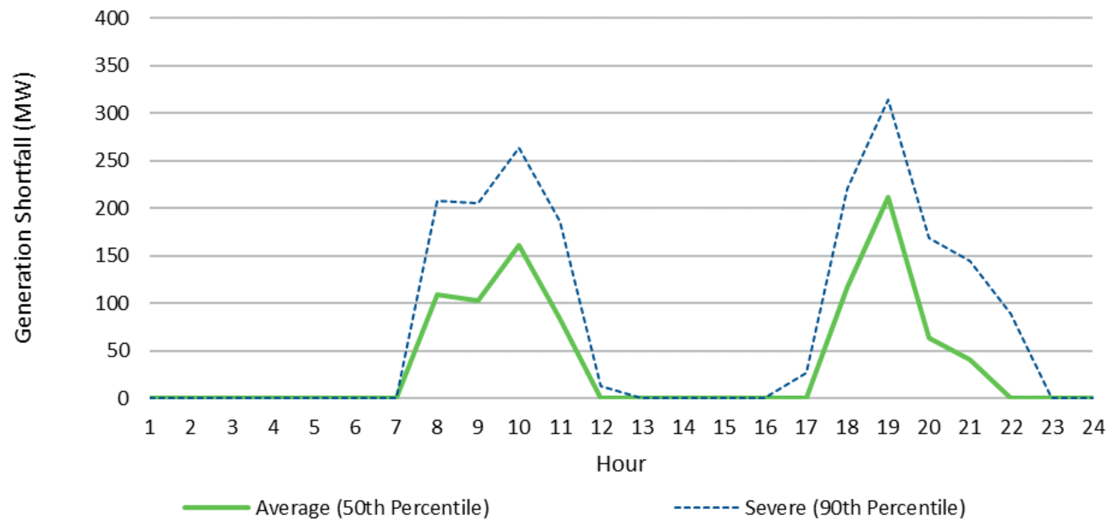

Chart 4: Shortfall on Peak Day (Combination A: Slow Decarbonization Case Load, Scenario 4ADH and 50 MW BESS Advanced to 2031)

Chart 5 depicts the shortfall duration curve for Combination A: Slow Decarbonization load forecast and Scenario 4ADH with 50 MW of BESS capacity advanced to 2031. In the Average Case (green line), a supply shortfall of over 100 MW occurs in approximately 2.5% of the time. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 10% of the time.

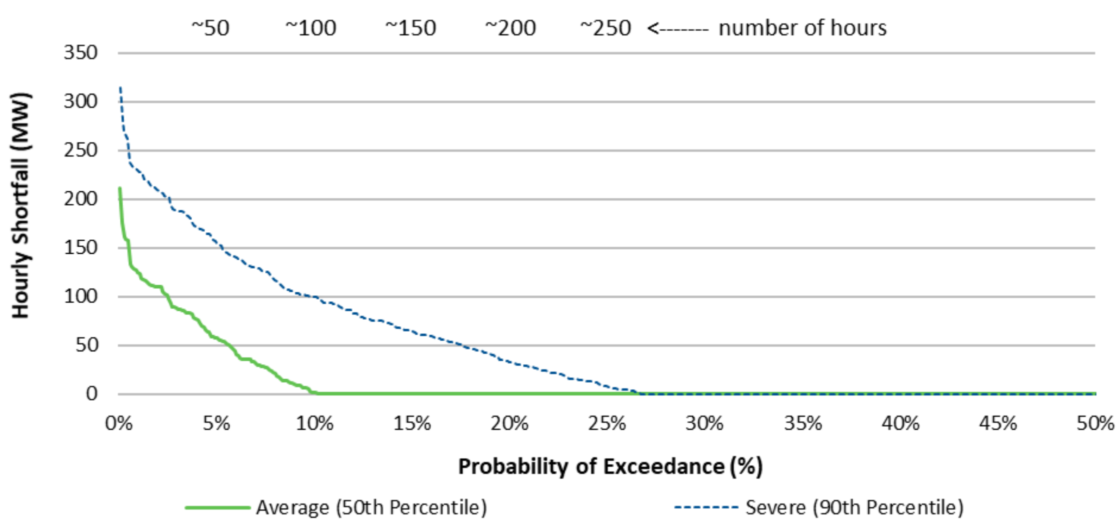

Chart 5: Shortfall Duration Curve (Combination A: Slow Decarbonization Case Load, Scenario 4ADH and 50 MW BESS Advanced to 2031)

The reduction in the peak shortfall between Scenario 4ADH (which is the same as Scenario 4AEF since the shortfall analysis is completed for 2032, before any differences in the Expansion Plans from these two scenarios), compared to Scenario 4ADH with 50 MW of BESS capacity advanced, is approximately 44 MW. This result indicates that 50 MW of BESS capacity would be comparable to other forms of dispatchable capacity when it comes to reducing generation shortfall. This relationship was demonstrated in the 2024 Resource Adequacy Plan.[13]

For ease of reference, Table 4 summarizes the results described in Combination A above.

Table 4: Summary of Combination A Shortfall Statistics

	Average Case	Severe Case
Hours of Shortfall	105	270
Total Energy Shortfall (GWh)	6.5	24
Peak Shortfall (MW)	212	315
% of Time Shortfall > 100 MW	2.5%	9.9%

Combination B Results

The results of the shortfall analysis for Combination B**:** Slow Decarbonization load forecast and Scenario 4ADH with 250 MW of BESS capacity[14] advanced to 2031 can be seen in Chart 6.

Under the Average Case (green line), unserved energy would be expected to occur in 32 hours over the six-week period, representing 1.8 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 173 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 280 MW with 136 hours of unserved energy over the period, representing 11 GWh of energy shortfall.

[13] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, sec. 6.2.1.1.5.
[14] On a firm capacity basis this would be comparable to advancing the 141.6 MW CT to 2031.

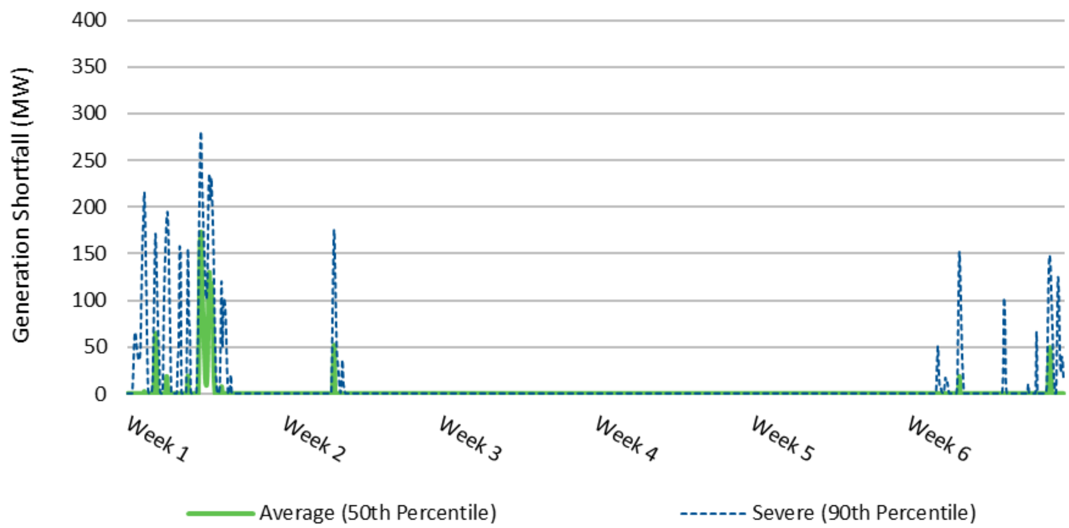

Chart 6: Shortfall over Six Weeks (Combination B: Slow Decarbonization Case Load, Scenario 4ADH and 250 MW BESS Advanced to 2031)

1 The estimated unserved energy during the peak day of the 2032 reference year for
2 Combination B: Slow Decarbonization load forecast and Scenario 4ADH with 250 MW of
3 BESS capacity advanced to 2031 can be seen in Chart 7.

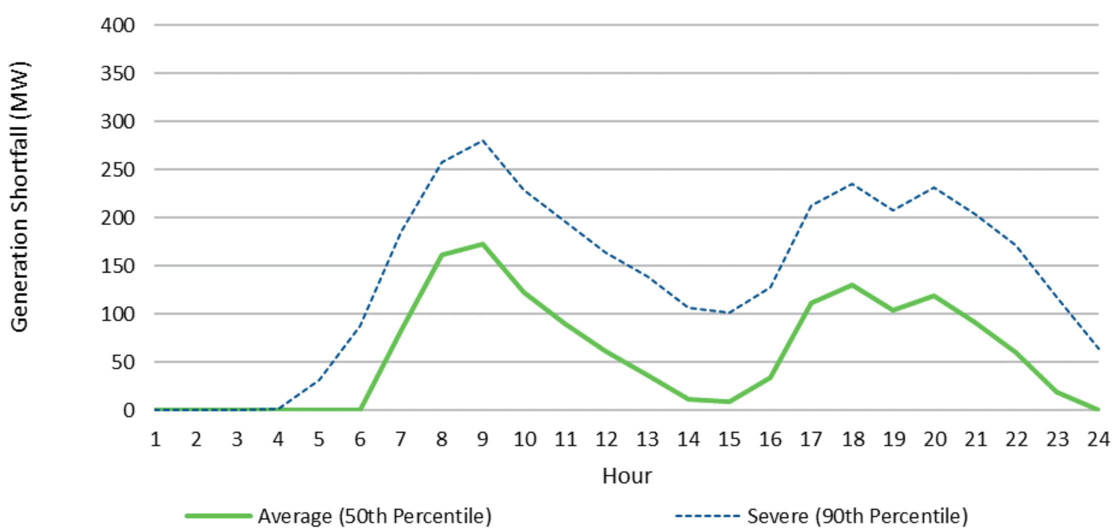

Chart 7: Shortfall on Peak Unserved Energy Day (Combination B: Slow Decarbonization Case Load, Scenario 4ADH and 250 MW BESS Advanced to 2031)[15]

[15] This graph represents the unserved energy on the peak unserved energy day (January 4) rather than the peak load day (January 3).

It is important to note that with the addition of 250 MW of BESS, the peak unserved energy day shifts from the day with the highest peak (January 3) to the following day (January 4), which has the highest daily energy requirements. **This reflects the fact that during high load days, there likely will not be enough available capacity on the system to charge the batteries, leading to shortages in energy rather than shortages in capacity.**

Chart 8 depicts the shortfall duration curve for Combination B: Slow Decarbonization load forecast and Scenario 4ADH with 250 MW of BESS capacity advanced to 2031. In the Average Case (green line), a supply shortfall of over 100 MW occurs approximately 0.7% of the time. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 5.0% of the time.

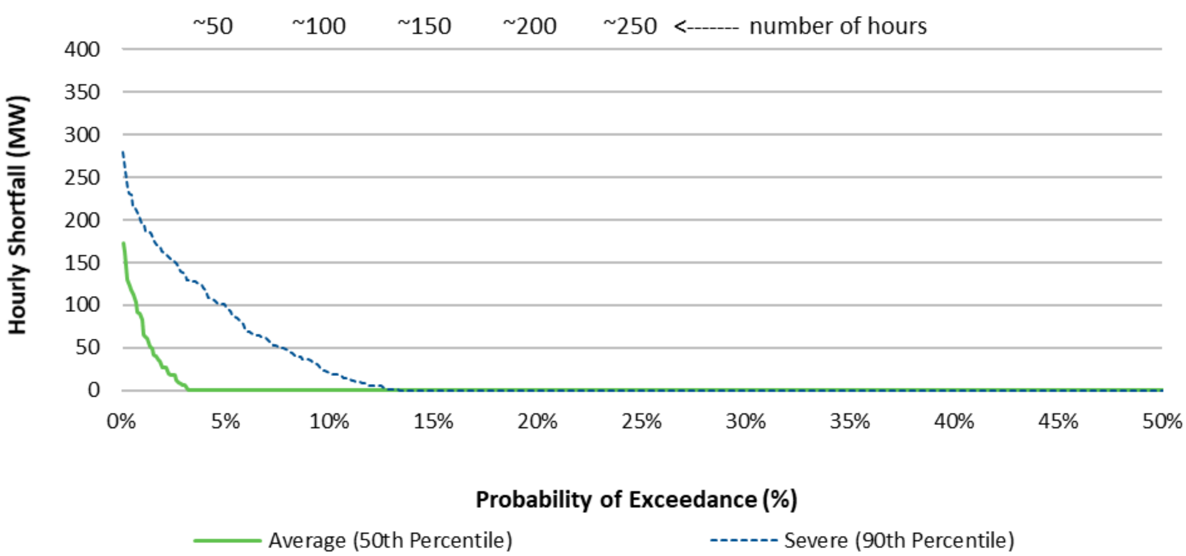

Chart 8: Shortfall Duration Curve (Combination B: Slow Decarbonization Case Load, Scenario 4ADH and 250 MW BESS Advanced to 2031)

As demonstrated by Chart 7, the effectiveness of BESS decreases as more BESS capacity is added. With the advancement of 250 MW of BESS capacity, the unserved energy is reduced by only 83 MW. **This indicates that batteries are effective when there is sufficient capacity to fully charge them, but their effectiveness is limited by the amount of surplus capacity available to charge the batteries in off-peak hours.**

For ease of reference, Table 4 summarizes the results described in Combination B above.

Table 4: Summary of Combination B Shortfall Statistics

	Average Case	Severe Case
Hours of Shortfall	32	136
Total Energy Shortfall (GWh)	1.8	10.9
Peak Shortfall (MW)	173	280
% of Time Shortfall > 100 MW	0.7%	5.0%

<u>Comparison to the Recommended Minimum Investment Required Expansion Plan</u>

The comparison of Scenario 4AEF(ADV) (Minimum Investment Required) with the results of the shortfall analysis for Combination B illustrates the relative effectiveness of BESS and Combustion Turbines in a shortfall scenario. Scenario 4AEF(ADV) (Minimum Investment Required) advances 141.6 MW of CT capacity to the reference year of 2032, while Combination B advances 250 MW of BESS capacity, equivalent to approximately 150 MW of firm capacity, to the same reference year. The shortfall statistic comparison between these scenarios is provided in Table 5.

Table 5: Summary of Scenario 4AEF(ADV) (Minimum Investment Required) and Combination B Shortfall Statistics

	Average (50th Percentile)			Severe (90th Percentile)		
	S4AEF (ADV)	Combination B	Delta	S4AEF (ADV)	Combination B	Delta
Peak Shortfall (MW)	124	173	+49	232	280	+48
Total Shortfall (GWh)	0.7	1.8	+1.1	6.9	10.9	+4.0
Hours of Shortfall (hr)	24	32	+8	102	136	+34

Under average conditions, the system can expect to see more and deeper outages with BESS compared to the Avalon CT, with an average of 8 more outage hours, 1.1 GWh of additional unserved energy and a peak shortfall of 49 MW greater.

Under severe conditions, the system can expect to see an average of 34 more outage hours, 4.0 GWh of additional unserved energy and a peak shortfall of 48 MW greater. **This clearly demonstrates that BESS would be less effective than the Avalon CT in a shortfall scenario.**

Q. Provide three additional LIL Shortfall Analysis runs to address BESS resources, potential hydrological resource constraints at Bay d'Espoir and the life extension of Hydro's thermal generation.

b) One LIL Shortfall Analysis run should be conducted that limits the output of Bay d'Espoir to match potential hydrological resource constraints identified in the Bates White Report.[1] Alternatively, Hydro could provide additional evidence that Bay d'Espoir will be able to produce at the collective output levels assumed in the LIL Shortfall Analysis runs included in the Application, and that those volumes can be deliverable to the Avalon Peninsula in all hours.

A. **b) Newfoundland and Labrador Hydro ("Hydro") confirms that the Bay d'Espoir ("BDE") system has adequate hydrology supply with the addition of BDE Unit 8, and has provided supplemental evidence that those volumes can be deliverable to the Avalon Peninsula in all hours under normal operating conditions.**

Discussion of the BDE system hydrology and the delivery of volumes via transmission is detailed below.

Bay d'Espoir System Hydrology

The hydrological resource constraints outlined by Bates White Economic Consulting, LLC ("Bates White") in Section III.H of the Bates White Report[2] appear to be based on a misinterpretation of the information Hydro provided, and, therefore, are not valid constraints. Hydro has already provided an assessment of the impact of an extended Labrador-Island Link ("LIL") outage on Island reservoir storage by an independent hydrology expert, Hatch Ltd. ("Hatch"), which confirmed that the system has adequate reservoir storage, including the addition of Unit 8, to make up for the loss of LIL imports to the Island

[1] Section III.H. LIL Shortfall Analysis, page 63.
[2] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025 ("Bates White Report").

by increasing generation from other sources until the start of spring freshet ("2024 Hatch Report").[3] In addition, the Hydrology and Feasibility Study for BDE Unit 8 was completed by the same independent hydrology expert, Hatch, who confirmed that the BDE system has adequate firm hydrology with the addition of Unit 8.[4] This study was completed in isolation of other generation sources that could positively impact resource storage and focused solely on the firm hydrology of the BDE system with the addition of Unit 8. Therefore, no additional analysis has been completed.

The Bates White Report stated:

> First, the LIL Shortfall Analysis assumes no new hydrological constraints associated with output from the Bay d'Espoir generating facility.[5] Hydro states that the maximum output of Bay d'Espoir, including BDE Unit 8, would be 767.8 MWh.[6] Hydro's LIL Shortfall Analysis results are consistent with this limitation, with no hours in which Bay d'Espoir's collective output exceeds 767.8 MW.[7] Hydro states that Bay d'Espoir produces 432.9 MWh for each million cubic meter ("MCM") of water consumed.[8] The LIL Shortfall Analysis results show that Bay d'Espoir is modeled to produce an average of 685.9 GWh during the six week outage across all model runs in the Combination 2 scenario,[9] which translates to consumption of approximately 1,597 MCM of water.
>
> Hydro also explains that the Maximum Operating Level of the Long Pond Reservoir (which supplies Bay d'Espoir) is 738 MCM in the winter season.[10] That amount is further limited by the minimum storage level of 355 MCM.[11] This suggests that the Long Pond Reservoir would have a maximum volume of 738 MCM entering winter and could release up to 383 MCM for consumption at Bay d'Espoir, far less than the 1,597 MCM modeled to be consumed at Bay d'Espoir in the LIL Shortfall Analysis. This gap is shown below in Figure [8]. Since the existing storage at Long Pond is insufficient to support Bay d'Espoir's modeled output during a LIL shortfall, the reservoir will necessarily require substantial inflows to support modeled output at the plant. Notably, these inflows would be needed just to support the existing Bay d'Espoir units (1-7), let alone any

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[3] "Impact of Prolonged Loss of LIL on Island Reservoir Levels," Hatch Ltd, July 2, 2024. Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, att. 5.

[4] *"Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8 – Addendum Report,"* Hatch Ltd, March 19, 2025. Please refer to "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 1, att. 2.

[5] Information Provided to Bates White.

[6] Information Provided to Bates White.

[7] Information Provided to Bates White.

[8] Hydro May 27, 2025 email to Bates White.

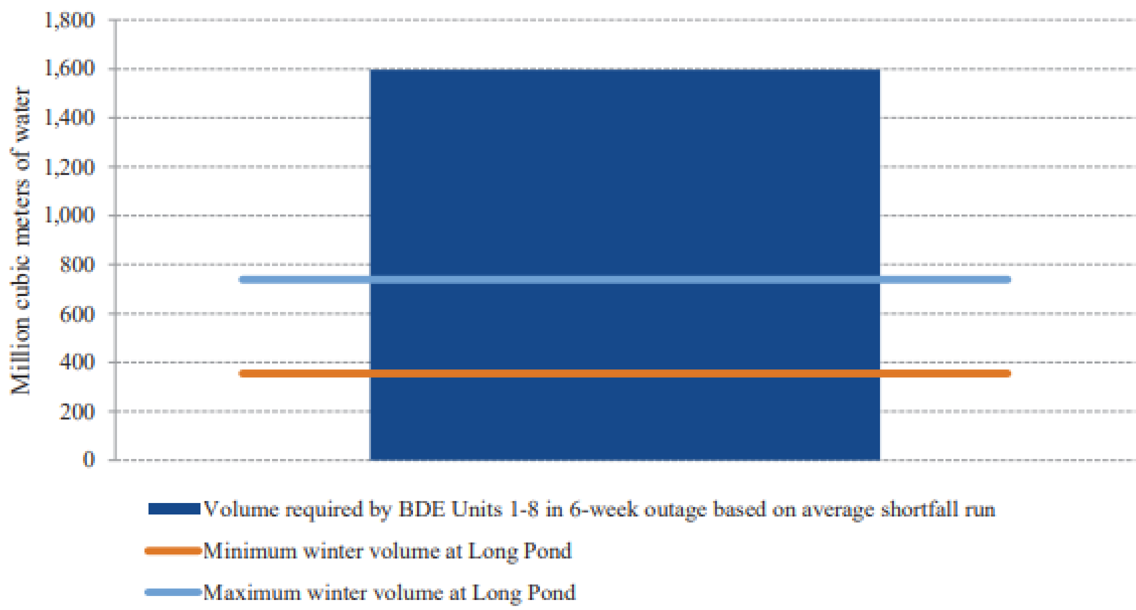
[9] Information Provided to Bates White.

[10] Information Provided to Bates White.

[11] Information Provided to Bates White.

incremental output from BDE Unit 8. Hydro has described winter as the "low inflow season"[12] and the "dry winter period (January and February),"[13] meaning the plant would need to tap its limited storage resources, including any supply from other reservoirs, to operate as planned.

Figure 8: Implied water consumption at BDE and Long Pond storage volumes during LIL shortfall[307]



Hydro has not fully addressed this issue in detail in its Build Application. The March 2025 Hatch study (included in the Build Application)[14] contained historical inflow data at BDE.[15] However, that data was provided on an annual average basis which prevents assessment of seasonal inflows. In its 2024 RAP, Hydro also provided Bay d'Espoir's average and firm energy capability given the most adverse three-year sequence of inflows in its historical record, which suggested average annual capability of 2,650 GWh and average annual firm capability of 2,096 GWh.[16] But this data, while useful, does not contain any seasonal granularity.

Even ignoring seasonality, the annual inflow data suggests that there may be hydrological limitations to Bay d'Espoir's ability to generate at output levels assumed in the LIL Shortfall Analysis. The LIL Shortfall Analysis shows that the

[12] Hydro, "Reliability and Resource Adequacy Review – Island Hydro Electric Supply Refresh Study," October 1, 2024, page 6 line 19.
[13] Hydro, "Reliability and Resource Adequacy Review – Island Hydro Electric Supply Refresh Study," October 1, 2024, Attachment 1, page 36.
[14] Build Application, Schedule 1, Attachment 2.
[15] Build Application, Schedule 1, Attachment 2, Figure 2-3.
[16] 2024 RAP, Appendix B, Table 13.

Bay d'Espoir generating plant will need to consume 1,597 MCM for the six-week period, or about 266 MCM/week. The March 2025 Hatch study contains a figure that suggests annual inflows were just over 500 cubic meters/second in 2019 and just under 400 cubic meters/second in 2017.[17] Converting these to weekly inflow units results in average weekly inflows of about 242 MCM/week (in 2017) and 302 MCM/week (in 2019).[18] These average annual inflows may not be enough to sustain Bay d'Espoir's operations as contemplated in the LIL Shortfall Analysis. Adjusting these average annual data for winter inflows, the "low inflow season" and "dry winter period (January and February)," as described by Hydro, only increases the risk.

As it stands, therefore, and absent additional evidentiary support from Hydro, the LIL Shortfall Analysis may overstate the reliability contribution of BDE Unit 8 to an extended bipole outage of the LIL. It is not clear from the data that the collective plant can produce the level of output assumed in the analysis. Hydro should address this issue in this proceeding to enhance confidence that its hydrological resources and expected inflows are sufficient to meet the demands of producing 685.9 GWh in a six-week winter outage, as is modeled in the LIL Shortfall Analysis.[19] To the extent that hydrological limitations bind the output of Bay d'Espoir in such a scenario, the incremental addition of another generating unit (i.e., BDE Unit 8) would seem to have limited positive impact.

Second, even ignoring any hydrological constraints, the assumed output of Bay d'Espoir in the LIL Shortfall Analysis is far above the historical average generation of the plant. Since January 1, 2015, the highest rolling six-week output of the collective Bay d'Espoir plant (units 1-7) is 464.21 GWh.[20] This six-week output from the plant would still be about 33 percent below the modeled output in the LIL Shortfall Analysis (691.4 GWh).[21] A review of Bay d'Espoir's historical and projected capacity factors underscores this point. Since 2015, Bay d'Espoir's collective capacity factor has averaged 49.4%.[22]The LIL Shortfall Analysis results in a collective capacity factor for the plant of 89.3% over the six-week period.[23] All this suggests that the LIL Shortfall Analysis is conditioned upon unprecedented performance from Bay d'Espoir. […]

Third, and even assuming that the Bay d'Espoir facility would have sufficient water resources to achieve the six-week output modeled in the LIL Shortfall Analysis, it would seem likely that at the end of the outage, Bay d'Espoir's

[17] Build Application, Schedule 1, Attachment 2, Figure 2-3.
[18] The conversion for 2017 equals 400 cubic meters/second * 60 seconds * 60 minutes * 24 hours * 7 days ÷ 1,000,000 = 241.92 MCM/week. For 2019, 500 cubic meters/second * 60 seconds * 60 minutes * 24 hours * 7 days ÷ 1,000,000 = 302.40 MCM/week.
[19] Information Provided to Bates White.
[20] This output occurred between February 14, 2022 and March 27, 2022. Over this six-week period, 19,342.20 MW were generated. 19,342.20 MW * 24 hr ÷ 1000 MWh/GWh = 464.21 GWh. Information Provided to Bates White.
[21] Information Provided to Bates White.
[22] Information Provided to Bates White.
[23] Information Provided to Bates White.

> hydrological resources would be exhausted and in need of replenishment. This takes time, and as storage levels are restored, it is possible that the plant would be derated (due to limited water), which could cause resource adequacy and reliability issues on the system.[24]

In their analysis in Figure 8, Bates White isolated the Long Pond Reservoir and failed to consider the water balance of the BDE system. Reservoir storage in the Long Pond Reservoir, which supplies the BDE Hydroelectric Generating Station, cannot be accurately determined by simply subtracting the maximum operating level from the low supply level, regardless of the season. Inflows into that reservoir are comprised of natural inflows from the watershed, turbined flows from the Upper Salmon Hydroelectric Generating Station, and, if necessary, bypass flows from North Salmon Dam. As a result, the reservoir receives a continuous and substantial volume of water into the Long Pond Reservoir, and its operation must adhere to defined reservoir operating limits (i.e., the maximum operating level and the low supply level).

Further, Hydro clarifies that the “minimum storage level of 355 MCM” referenced in paragraph 142 of the report is not a minimum operating level for the Long Pond Reservoir, but instead the lowest Maximum Operating Limit of the reservoir during the winter season. The Maximum Operating Limit of the Long Pond Reservoir varies seasonally due to variances in flood handling requirements in each season. In winter, the Maximum Operating Limit is a function of the snow pack, or snow water equivalent (“SWE”), in the Long Pond Watershed. The limit goes from a maximum of 738 MCM with a SWE from 0–50 mm to a minimum of 355 MCM with a SWE greater than 215 mm. SWE is a measurement of the water contained within the snowpack, expressed as the amount of liquid water that would result if the snow were melted into a liquid state. These limits are to ensure sufficient storage capacity to handle the Probable Maximum Flood event. The Probable Maximum Flood is defined as the largest theoretical flood event that could occur at a specified location. The Low Supply Level is at Elevation 178.31 m (0 MCM storage) as shown in Attachment 1 of this response.[25] It is also important to note, the Low Supply Level represents the lowest reservoir elevation at

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[24] “Export Report of Vincent Musco and Collin Cain,” Bates White Economic Consulting, LLC, June 26, 2025, sec. III. H., para. 141–147, pp. 64–68.
[25] Please refer to Attachment 1 for information previously provided to Bates White.

which the BDE plant can achieve its full rated capacity. The plant may continue to operate at lower elevations; however, it would be at a derated capacity.

The Plexos Reliability Model was used to conduct the LIL Shortfall Analysis as it is the appropriate model to quantify generation shortfall due to unit outage(s) and subsequent loss of load events; however, it is not an appropriate model to test the hydrology consequences of such events in a hydro-dominant system. Instead, Hydro contracted Hatch to use a hydrology-specific model, Vista, to complete an assessment of the impact a prolonged loss of LIL has on Island reservoir levels. This 2024 Hatch Report was provided within the 2024 Resource Adequacy Plan as Appendix C, Attachment 5.

This study fully assessed the impact of a prolonged loss of the LIL (i.e., six-week shortfall) on Island reservoir levels using the full hydrological record since 1958. To be clear, the full hydrological record includes all low inflow sequences that the system has experienced since 1958 and is input into the model on a daily timestep. In this study, two six-week outage scenarios were considered; one beginning in January when demand is at its highest, and one in March before spring freshet, when system hydrology is historically at its weakest. Both scenarios were completed for the existing system today, as well as the future system in 2032, based on the recommended Minimum Investment Required Expansion Plan as reported in the 2024 Resource Adequacy Plan. The Vista model was also run using the assumption that a LIL outage did not occur, to enable a comparison of the impact that the LIL loss has on thermal and hydro generation on the system in this extreme circumstance.

Results from <u>all simulations</u>, including the outage case simulations, indicate that the BDE system has adequate hydrology supply with the addition of BDE Unit 8. The low supply level of the reservoirs in the BDE system, including Long Pond, was not violated. In addition, in no scenario was the bypass of North Salmon Dam required, which is an additional option to supply Long Pond and thus further support the BDE Hydroelectric Generating Station, if necessary.

Further, the projected production of the BDE Hydroelectric Generating Station in the analysis provided by Hydro, compared to the historic average generation from this plant, is not a reasonable approach for two reasons:

i. The BDE Hydroelectric Generating Station is considered a "swing plant," meaning that as demand on the system fluctuates throughout the day, the BDE plant generation is reduced or increased to match changes in load, and to accommodate variations in LIL deliveries, Maritime Link imports, Maritime Link exports, or any other reductions or increases in generation, on the Island Interconnected System. Comparing generation data from this plant during a period when the Holyrood Thermal Generating Station was operating continuously during the winter period, against a materially different resource composition in the future where this 490 MW thermal facility is retired, is not an appropriate comparison. This is one of the primary reasons why the 2024 Hatch Report included scenarios for the existing system today as well as the future system in 2032.[26] The Vista model was also run using the assumption that a LIL outage did not occur, to enable a comparison of the impact that the LIL loss has on thermal and hydro generation on the system in this extreme circumstance. The addition of BDE Unit 8 will not change the way the plant is operated as a "swing plant" on the Island Interconnected System.

ii. Hydro plans for the availability of 10-minute and 30-minute operational reserves for the Newfoundland and Labrador Interconnected System.[27] All hydroelectric generating stations on the Island, including the BDE plant, contribute to reserve requirements in some respect. The 10-minute reserve requirement takes into consideration each hydroelectric unit's start-up time, ramp rate, and availability. During normal operation of the Island Interconnected System, the historic generation of the BDE plant will not reflect full output because it would violate Hydro's operational reserve requirement. Maximized units severely reduce or eliminate reserve contribution capability. Because the BDE plant is the "swing plant" on the Island Interconnected System, these units often contribute heavily to Hydro's reserve requirements to allow other hydroelectric units on the Island to be optimized and system energy in storage to be effectively managed. The addition of BDE Unit 8 will positively contribute to Hydro's 10-minute reserve requirements and

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[26] Based on the recommended Minimum Investment Required Expansion Plan as reported in the 2024 Resource Adequacy Plan.
[27] Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, sec. 3.5 for details on the operational capacity criterion.

will be a material benefit for generation outage planning during Hydro's annual maintenance season.

<u>Volume Delivery</u>

Hydro confirms that the volumes are deliverable to the Avalon in all hours and are not impacted by transmission constraints under normal operating conditions (i.e., LIL is in service and Avalon generation is available). Capacity from the BDE Hydroelectric Generating Station, including BDE Unit 8, is fully deliverable during normal operation.

The assessment by Bates White, which concluded that only 67 MW can be delivered to the Avalon during normal operation, is incorrect.

Bates White makes the following statement in its report:

> The 230 kV Bay d'Espoir-Soldiers Pond transmission segment is currently limited to 680 MW (normal operations) or 603 MW (during a LIL bipole outage), which can limit the maximum collective output of the existing Bay d'Espoir units 1-7 (613 MW). Absent transmission solutions, this constraint prevents transmission of any incremental output from BDE 8 during a LIL bipole outage, exactly when that output is needed most. Even during normal operations with the LIL in service, just a fraction (67 MW out of 154.4 MW) of the incremental output from BDE 8 is deliverable.[28]

Bates Whites' methodology did not account for several fundamental factors that influence power transfer from BDE to Soldiers Pond ("SOP") during normal operation. Specifically, the assessment omitted considerations such as LIL imports, Avalon generation, and overall Island demand. Under normal operating conditions with BDE Unit 8 in service, there are no scenarios in which the 680 MW transfer limit would be exceeded.

An essential dynamic that was not reflected in Bates White's analysis is that Avalon generation and LIL imports help reduce the flow on the 230 kV corridor from BDE to SOP.

To demonstrate that BDE volumes at the collective output levels assumed in the LIL Shortfall Analysis runs included in the 2025 Build Application are deliverable during all hours, Hydro

[28] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025, sec. II, para. 12, p. 10.

has provided the 2034–35 Peak Load Flow Cases presented in the 2025 NLSO[29] Annual Assessment (Appendix B).[30] As shown in Figure 1, the eastward power flow from BDE would be the combined flow of Transmission Lines TL202, TL206 and TL267 of approximately 340 MW.[31] In this example, LIL imports are assumed to be 720 MW[32] and the total output of the existing Holyrood CT and proposed Avalon CT is set to approximately 340 MW.[33] This would be considered a normal operating scenario during peak conditions.

Figure 1 shows that BDE Unit 7 and 8 are at full capacity (154 MW each), while the Units 1 to 6 are at 78% of their capacity. With the LIL in service, the total transfer capacity eastward from BDE is 680 MW. Given the observed flow of 340 MW, this leaves approximately 50% of the transmission capacity unused during normal operation.[34] **This analysis clearly demonstrates that the BDE to SOP transmission system does not constrain Hydro's ability to deliver BDE Unit 8 power to the Avalon Peninsula.**

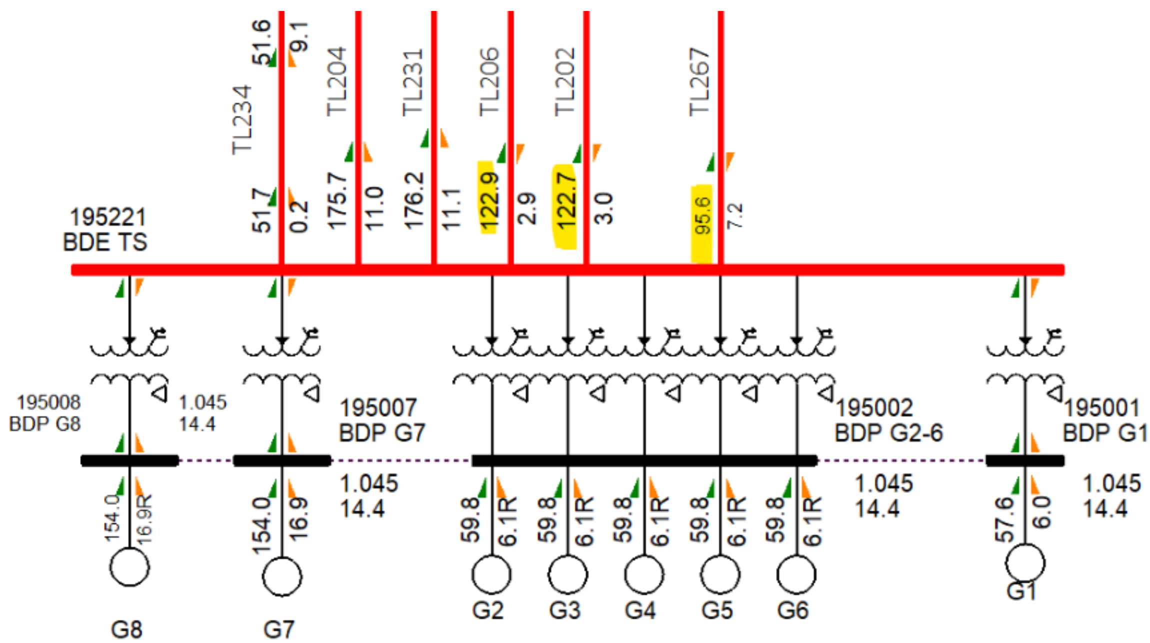

Figure 1: Load Flow Diagram – 2034-35 Peak Load Case

[29] Newfoundland and Labrador System Operator ("NLSO").
[30] "NLSO Report – 2025 Annual Planning Assessment – Doc # TP-R-092," Newfoundland and Labrador Hydro, May 6, 2025, app. B.
[31] TL202 (122.7 MW) + TL206 (122.9 MW) + TL267 (95.6 MW) = 341.2 MW.
[32] Measured at Muskrat Falls.
[33] It is also assumed that there is an additional 39 MW of Newfoundland Power Inc. Avalon Generation and 6 MW of wind generation at Fermeuse, which is not included in the 340 MW total.
[34] Transfer capacity eastward from BDE (680 MW) – output of Holyrood CT and future Avalon CT (340 MW) = 340 MW.

Figure 2 presents the load flow results for the same scenario with the existing Holyrood CT and the proposed Avalon CT offline. This would **not** be considered normal operation. The flow east out of BDE would be the combined flow of TL202, TL206 and TL267 of approximately 585 MW,[35] which would be approximately 86% of full capacity.[36] Under abnormal operating conditions with BDE Unit 8 in service, the 680 MW transfer limit may only be reached in exceptional circumstances.[37]

In conclusion, outside of a LIL shortfall, the existing transmission is sufficient to deliver the energy from BDE 8 to the Avalon Peninsula in normal operating conditions and most abnormal operating conditions.

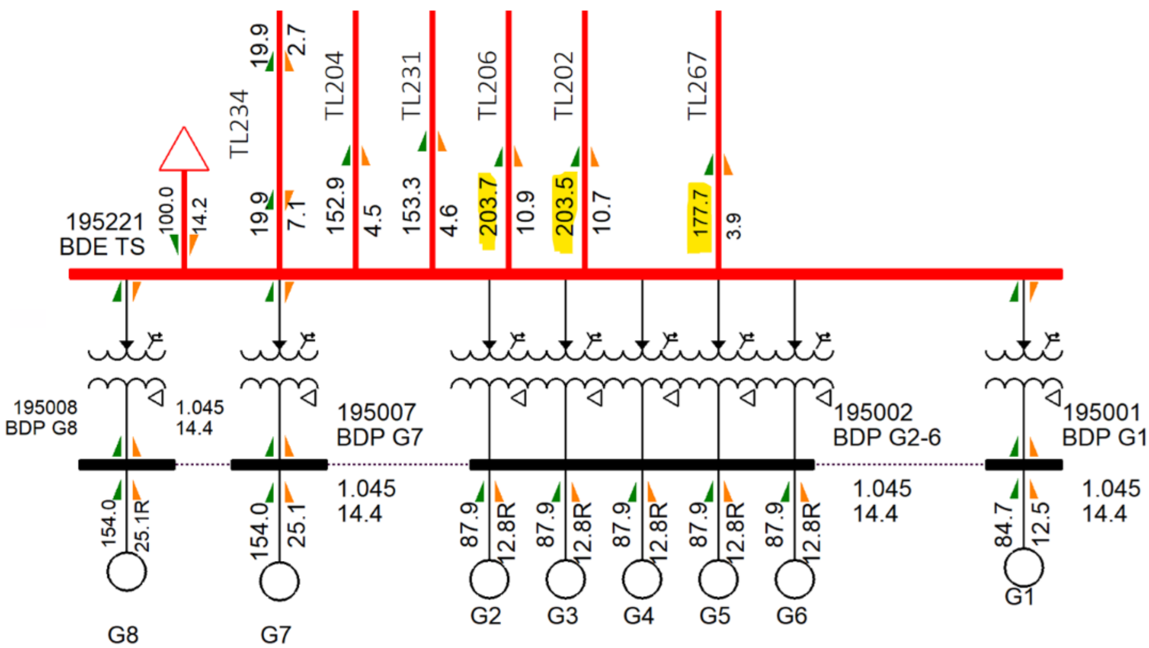

Figure 2: Load Flow Diagram – 2034–35 Peak Load Case (No Avalon Thermal Generation)

During a LIL shortfall, required volumes will be deliverable through expanded transmission capacity. Hydro has received the final study from its consultant, TransGrid Solutions Inc., which has concluded that the Remedial Action Scheme can be implemented in concert with BDE Unit 8 and the Avalon CT to eliminate the need for additional transmission upgrades in

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[35] TL202 (203.5 MW) + TL206 (203.7 MW) + TL267 (177.7 MW) = 584.9 MW.
[36] 585 MW combined flow/transfer capacity eastward from BDE (680 MW) = 86% of full capacity.
[37] Under an extremely rare situation during peak conditions in which there is limited Avalon generation available **and** LIL imports are significantly de-rated, BDE to SOP flow could reach the 680 MW transfer limit.

the Minimum Investment Required Case. For further information, please refer to question 12 of this proceeding. Hydro will file a report on this solution in October 2025, as noted in its response to question 11 of this proceeding.

Q. **Reference: (Sessions 1, 4)**

For BDE (1-8, collectively), please provide:

- **a)** Maximum operating level (in both cubic meters of water/hour and GWh)
- **b)** Minimum reservoir storage limit (in both cubic meters and GWh)
- **c)** Highest daily output from BDE (collective, units 1-7) since January 1, 2019

Average daily output, by calendar day, for 10-year historical period used in NLH’s modeling (collective, units 1-7)

a) The Maximum Operating Level (MOL) of the Long Pond Reservoir which supplies the Bay d’Espoir Hydroelectric Generating Station varies seasonally from 355 MCM (154 GWh) to 829 MCM (359 GWh) due to variances in flood handling requirements in each season. In winter, the MOL is a function of the snowpack in the Long Pond basin and is a maximum of 738 MCM (319 GWh) with a snow water equivalent[1] (SWE) from 0-50 mm and a minimum of 355 MCM (154 GWh) with a SWE greater than 215 mm. In spring, the MOL begins increasing on April 1 until it reaches its maximum of 829 MCM (359 GWh) by June 1. It remains at this elevation until July 1 when the MOL begins decreasing to its fall maximum of 738 MCM (319 GWh) by September 1. The MOL of the Long Pond reservoir will remain unchanged with the addition of Bay d’Espoir Unit 8. The maximum output of Bay d’Espoir Units 1 through 8 is 767.8 MW, which is expected can be sustained as required, provided storage is available in the Long Pond reservoir.

In terms of maximum plant output, assuming Bay d’Espoir Unit 8 has the same output capability as Unit 7, the total maximum output capability of Bay d’Espoir Units 1-8 would be 0.7678 GWh or 1.77 MCM/hour.

[1] Snow water equivalent quantifies the volume of water that is in melted snow. It is the depth of water that would cover the ground if the snowpack was in a liquid state. The SWE is less than the depth of snow on the ground because snow contains a mix of water (ice and liquid) and air.

b) Minimum reservoir storage limits are developed annually to provide guidance in the reliable operation of Hydro's major reservoirs—Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage limit is designed to indicate the minimum level of aggregate storage required each month such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, Hydro's load can still be met through the use of the available hydraulic storage supplemented with maximized deliveries of power from the Muskrat Falls Hydroelectric Generating Station (MFGS) over the Labrador-Island Link (LIL). Hydro's long-term critical dry sequence is defined as January 1959 to March 1962 (39 months). Other dry periods are also considered during this analysis to ensure that no other shorter-term historic dry sequence could result in insufficient storage.

The monthly aggregate reservoir storage limits are developed each year with consideration of the historic inflow sequences, generating plant availability, Labrador Island Link availability, and system load forecasts. Total system storage, including storage from the Long Pond reservoir which feeds into the Bay d'Espoir Hydroelectric Generating Station, is continuously monitored against the established minimum limits. Power deliveries from MFGS via the LIL can be increased when necessary to improve system storage to the extent energy is available from Muskrat Falls under the existing agreements. Other factors, such as the distribution of storage among the reservoirs, weather forecasts, and approximations of the water equivalent in snowpack would also be considered in making the decisions related to delivering more power to the island.

This is different from the Low Supply Level which is at El. 178.31 m (0 MCM). This is the lowest elevation at which a rated flow of 397 m^3/s can be maintained.

c) Since January 1, 2019, the highest daily output from the Bay d'Espoir Hydroelectric Generating Station has been 31.25 MCM on January 13, 2023. This equates to approximately 13.5 GWh. Historical daily output from the Bay d'Espoir Hydroelectric Generating Station, in average MW, can be seen in the attached spreadsheet.

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1-Jan	498	404	349	446	381	394	324	414	298	476	264
2-Jan	461	285	340	423	322	385	414	355	332	458	257
3-Jan	496	364	340	448	394	403	380	364	374	480	225
4-Jan	510	370	406	480	430	393	375	447	381	489	347
5-Jan	454	371	313	365	293	393	385	424	474	485	264
6-Jan	462	355	377	446	193	420	347	240	484	451	146
7-Jan	479	359	392	497	265	418	288	310	427	465	202
8-Jan	481	366	424	519	390	413	277	342	444	429	314
9-Jan	462	371	444	490	397	411	283	430	494	430	328
10-Jan	496	387	436	479	293	468	318	332	506	467	371
11-Jan	491	382	398	482	225	412	380	469	500	413	365
12-Jan	480	350	373	364	208	422	465	438	538	361	385
13-Jan	473	398	383	175	347	431	475	378	529	404	372
14-Jan	464	388	501	246	306	477	463	242	432	448	464
15-Jan	468	365	418	409	326	479	436	246	356	321	464
16-Jan	468	319	418	401	389	423	393	456	436	360	430
17-Jan	431	316	405	394	405	407	340	468	352	388	444
18-Jan	479	283	396	395	472	408	316	430	416	380	435
19-Jan	431	271	394	412	431	505	348	437	421	390	393
20-Jan	386	338	338	444	449	387	423	426	426	349	305
21-Jan	440	363	389	458	292	440	450	452	436	283	410
22-Jan	459	400	412	522	257	423	441	491	439	335	470
23-Jan	444	394	423	486	279	401	461	427	416	425	470
24-Jan	443	368	399	443	255	330	456	365	413	481	408
25-Jan	394	385	394	456	133	394	466	332	406	434	418
26-Jan	438	383	348	434	292	338	434	364	462	455	406
27-Jan	481	286	343	432	346	269	400	500	455	398	347
28-Jan	406	358	330	379	331	251	423	501	466	337	285
29-Jan	378	389	340	373	372	274	449	426	435	341	362
30-Jan	412	362	333	447	445	285	392	380	440	403	367
31-Jan	393	390	401	393	390	349	386	431	416	411	391
1-Feb	347	265	433	456	456	366	414	452	496	383	393
2-Feb	448	228	418	318	486	361	390	486	472	381	412
3-Feb	454	350	420	345	454	300	332	425	486	374	453
4-Feb	446	336	464	483	470	254	255	383	498	406	313
5-Feb	409	227	499	445	393	315	301	393	489	403	433
6-Feb	410	229	478	394	395	375	282	484	466	401	436
7-Feb	439	319	483	432	436	370	326	496	482	432	400
8-Feb	381	381	483	427	433	349	376	454	440	440	462
9-Feb	429	371	377	468	391	364	396	392	412	418	448
10-Feb	444	339	426	495	454	378	412	356	446	440	456
11-Feb	407	324	429	425	461	272	489	307	358	349	461
12-Feb	491	361	412	383	445	342	458	280	413	359	483
13-Feb	452	410	439	437	457	361	409	250	466	366	415
14-Feb	453	377	440	504	411	440	422	424	470	379	398
15-Feb	509	427	425	412	404	463	403	460	417	365	433
16-Feb	461	445	406	434	411	379	413	500	479	393	338
17-Feb	511	331	333	473	325	293	391	481	492	338	333
18-Feb	457	238	343	501	400	348	398	344	474	404	336
19-Feb	442	328	383	449	373	406	443	411	501	395	292
20-Feb	422	373	388	379	430	399	471	448	461	399	340
21-Feb	421	376	408	456	442	467	479	466	296	429	377
22-Feb	444	306	383	405	382	423	461	478	360	443	357
23-Feb	422	336	373	473	389	284	400	447	422	277	380
24-Feb	448	369	396	471	396	251	334	424	510	271	336
25-Feb	445	346	406	413	380	227	301	495	522	275	323
26-Feb	471	148	347	436	262	231	280	492	516	375	336

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
27-Feb	496	206	306	377	362	318	322	464	475	297	291
28-Feb	503	280	341	313	375	325	367	455	464	130	315
29-Feb		211				230				160	
1-Mar	489	166	377	419	331	313	303	468	418	283	301
2-Mar	451	217	389	394	317	288	314	486	434	307	300
3-Mar	444	222	396	387	354	341	363	410	365	157	431
4-Mar	481	349	480	394	305	228	346	476	324	312	511
5-Mar	458	350	509	446	297	227	281	507	376	310	417
6-Mar	465	254	443	487	374	249	332	494	438	328	366
7-Mar	443	310	424	451	391	350	380	439	411	259	261
8-Mar	430	321	416	458	413	288	379	456	501	313	319
9-Mar	435	371	355	412	428	394	385	456	500	255	316
10-Mar	480	367	356	435	427	467	362	505	489	411	343
11-Mar	431	369	412	407	420	451	396	483	492	429	365
12-Mar	440	378	472	397	310	420	308	481	482	300	394
13-Mar	472	336	406	373	322	336	278	413	466	184	426
14-Mar	470	392	403	487	340	323	299	519	472	254	463
15-Mar	446	356	419	464	305	377	393	464	498	354	378
16-Mar	463	332	308	386	298	441	418	492	483	342	432
17-Mar	422	284	393	421	291	415	424	476	448	316	297
18-Mar	403	289	374	399	362	358	371	395	420	356	219
19-Mar	383	304	373	463	440	329	346	375	418	324	331
20-Mar	407	387	399	416	446	370	324	464	462	277	352
21-Mar	407	385	412	388	354	286	296	468	403	308	302
22-Mar	437	371	374	402	298	402	170	463	413	380	260
23-Mar	467	415	431	397	254	388	202	482	480	364	325
24-Mar	426	412	459	456	266	377	244	473	531	398	322
25-Mar	415	404	412	482	289	370	258	482	503	364	360
26-Mar	381	364	456	460	309	326	244	481	480	358	388
27-Mar	338	364	434	416	328	327	405	446	454	373	426
28-Mar	379	329	396	443	322	279	459	362	449	314	438
29-Mar	396	291	400	438	330	329	424	389	443	197	440
30-Mar	356	260	420	379	322	376	375	435	445	251	405
31-Mar	347	258	445	375	271	314	321	399	423	339	349
1-Apr	332	224	418	402	259	327	321	434	380	358	254
2-Apr	404	90	428	389	323	249	206	392	373	345	261
3-Apr	407	82	415	467	334	308	154	417	369	430	248
4-Apr	388	278	398	472	323	383	190	362	376	348	345
5-Apr	354	335	399	441	359	423	207	404	340	386	282
6-Apr	374	335	399	428	365	437	248	430	355	336	319
7-Apr	370	305	400	467	371	411	232	435	379	319	248
8-Apr	430	204	368	416	433	425	224	489	351	370	323
9-Apr	414	133	318	449	415	411	188	517	420	403	369
10-Apr	397	161	353	370	384	444	291	450	386	398	341
11-Apr	326	253	347	415	368	348	307	435	310	308	292
12-Apr	330	329	392	392	348	324	345	419	318	334	297
13-Apr	342	249	393	439	286	334	312	387	397	207	312
14-Apr	309	255	382	434	277	318	363	422	344	182	336
15-Apr	323	345	407	479	377	381	373	414	346	201	326
16-Apr	409	338	349	393	367	413	336	392	321	181	352
17-Apr	398	347	380	369	399	447	299	301	352	212	326
18-Apr	375	362	416	386	417	411	351	301	260	341	320
19-Apr	348	348	397	369	416	453	283	320	354	301	342
20-Apr	354	416	422	406	324	400	384	412	414	260	316
21-Apr	349	403	407	348	261	418	371	393	371	279	343
22-Apr	343	368	369	340	184	348	277	383	364	298	341
23-Apr	336	324	305	315	277	349	264	386	366	304	277

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
24-Apr	321	356	271	271	413	380	273	390	381	341	329
25-Apr	368	361	301	227	372	374	265	342	365	217	336
26-Apr	268	384	327	256	322	314	276	304	348	286	381
27-Apr	292	392	307	236	275	393	338	358	325	287	371
28-Apr	267	380	292	213	262	431	311	358	340	274	347
29-Apr	277	374	198	187	337	416	284	363	309	249	343
30-Apr	274	366	251	242	412	375	318	353	270	264	372
1-May	279	326	307	322	424	320	304	354	313	319	
2-May	200	340	363	265	397	279	255	386	331	326	
3-May	214	335	383	312	385	313	342	431	328	351	
4-May	151	330	272	338	293	368	323	451	343	283	
5-May	114	343	220	335	245	394	321	430	380	270	
6-May	107	335	222	239	272	367	356	396	385	258	
7-May	317	243	225	292	328	341	290	361	303	220	
8-May	342	168	303	297	322	350	286	297	299	244	
9-May	326	207	318	209	320	287	287	292	366	248	
10-May	281	272	291	256	329	284	302	266	303	297	
11-May	313	252	303	257	323	305	265	248	295	338	
12-May	334	308	261	279	330	346	301	191	297	301	
13-May	324	325	296	278	297	370	258	239	230	249	
14-May	293	275	237	241	244	413	270	290	224	267	
15-May	342	287	215	246	351	433	257	331	274	305	
16-May	332	275	248	254	347	377	283	335	247	240	
17-May	331	309	211	301	314	333	253	311	211	269	
18-May	343	265	172	273	297	385	301	286	233	274	
19-May	295	228	199	236	330	386	301	273	242	258	
20-May	209	189	276	237	305	277	323	212	195	195	
21-May	297	178	328	253	352	163	292	149	165	242	
22-May	330	259	299	269	443	140	289	153	256	244	
23-May	282	275	241	314	409	257	296	122	312	266	
24-May	244	227	292	336	373	177	370	229	286	254	
25-May	206	223	278	333	195	218	391	307	300	301	
26-May	154	223	276	332	184	136	371	256	319	366	
27-May	201	251	329	326	251	207	290	282	284	352	
28-May	248	290	318	277	238	166	310	285	213	317	
29-May	235	295	373	246	213	160	266	292	313	277	
30-May	261	232	280	318	146	148	236	252	293	230	
31-May	227	254	230	340	213	167	254	290	248	287	
1-Jun	279	277	249	220	273	232	227	313	292	309	
2-Jun	286	294	234	236	234	281	208	316	340	245	
3-Jun	285	283	307	272	203	265	199	290	346	225	
4-Jun	275	232	280	303	165	216	240	335	352	258	
5-Jun	245	265	274	237	202	130	221	345	329	256	
6-Jun	252	277	299	260	264	163	273	285	339	246	
7-Jun	257	196	259	239	192	237	329	316	313	214	
8-Jun	246	293	267	240	209	242	246	344	191	189	
9-Jun	253	330	212	267	254	310	217	306	175	241	
10-Jun	246	338	176	182	249	303	327	272	224	262	
11-Jun	228	306	206	211	240	279	356	189	186	226	
12-Jun	210	216	170	212	234	260	304	173	215	207	
13-Jun	219	269	275	248	189	182	311	223	212	186	
14-Jun	237	311	209	243	164	213	319	305	283	225	
15-Jun	232	313	251	219	271	254	350	239	263	267	
16-Jun	214	271	245	245	288	203	366	257	272	255	
17-Jun	232	323	219	220	290	194	280	273	263	244	
18-Jun	179	346	192	257	214	135	227	244	275	210	
19-Jun	183	305	214	249	188	190	189	197	340	212	

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
20-Jun	159	203	213	197	202	223	238	221	301	167	
21-Jun	200	222	140	178	218	282	261	226	262	140	
22-Jun	230	219	185	184	212	224	246	238	247	140	
23-Jun	225	233	165	119	197	198	266	208	205	147	
24-Jun	257	248	174	154	214	192	260	201	199	160	
25-Jun	266	242	122	241	222	176	305	191	192	182	
26-Jun	249	232	147	273	215	151	284	248	221	182	
27-Jun	226	246	135	245	204	161	233	206	255	188	
28-Jun	201	243	170	230	177	129	207	163	218	272	
29-Jun	201	250	180	217	143	139	238	180	178	272	
30-Jun	180	247	172	211	136	132	247	219	211	235	
1-Jul	155	240	138	223	174	100	207	199	182	219	
2-Jul	155	241	127	225	203	250	231	212	191	240	
3-Jul	162	247	100	248	190	233	260	166	211	212	
4-Jul	133	282	118	274	214	244	284	163	212	207	
5-Jul	146	280	163	266	178	250	333	159	174	211	
6-Jul	231	290	165	214	151	221	271	153	179	169	
7-Jul	239	307	159	204	129	242	245	175	167	166	
8-Jul	218	296	166	246	159	214	271	145	161	179	
9-Jul	167	294	164	217	167	231	322	164	189	129	
10-Jul	221	288	258	253	191	242	246	178	292	112	
11-Jul	225	284	239	252	224	212	244	229	275	104	
12-Jul	236	254	191	241	156	195	254	224	267	115	
13-Jul	222	300	177	229	136	227	276	307	274	79	
14-Jul	254	276	193	247	168	266	221	278	274	98	
15-Jul	242	271	170	267	219	283	246	295	217	114	
16-Jul	227	261	174	248	168	324	308	242	271	184	
17-Jul	186	216	205	270	149	301	320	248	297	204	
18-Jul	170	260	215	259	192	273	300	245	295	231	
19-Jul	224	252	212	223	174	237	337	246	284	230	
20-Jul	239	254	177	283	161	266	335	230	321	226	
21-Jul	252	256	207	258	163	292	375	224	305	241	
22-Jul	238	221	187	243	196	235	336	214	259	216	
23-Jul	167	174	134	275	160	202	348	221	223	205	
24-Jul	236	176	162	268	163	193	295	205	252	226	
25-Jul	226	216	141	252	248	169	251	199	250	246	
26-Jul	263	239	200	266	166	206	274	217	221	224	
27-Jul	179	250	197	260	234	251	280	229	165	139	
28-Jul	200	251	185	287	248	257	243	231	173	156	
29-Jul	187	203	191	249	253	257	111	233	195	189	
30-Jul	213	211	236	245	268	238	112	216	193	178	
31-Jul	215	216	245	213	250	227	101	188	178	189	
1-Aug	200	234	262	244	276	215	103	207	211	180	
2-Aug	222	257	259	221	227	214	132	221	202	228	
3-Aug	233	283	256	235	206	188	124	220	203	241	
4-Aug	255	271	272	231	262	202	139	223	181	260	
5-Aug	247	256	264	237	254	226	218	207	197	268	
6-Aug	260	264	269	282	229	221	231	197	198	233	
7-Aug	234	223	310	285	206	209	223	182	194	169	
8-Aug	220	237	275	293	237	220	241	229	215	187	
9-Aug	247	260	295	318	242	242	242	263	176	205	
10-Aug	259	252	294	272	216	273	251	252	232	163	
11-Aug	296	248	317	263	225	264	258	276	192	208	
12-Aug	268	226	321	237	223	303	289	233	153	211	
13-Aug	290	207	278	273	234	292	292	223	144	249	
14-Aug	232	237	259	290	194	247	287	166	179	251	
15-Aug	153	244	291	284	236	241	284	177	185	250	

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
16-Aug	138	200	273	249	234	295	288	279	182	353	
17-Aug	187	208	300	279	203	295	251	277	215	300	
18-Aug	226	268	263	269	191	316	248	302	186	252	
19-Aug	192	244	242	233	209	307	244	262	132	303	
20-Aug	143	237	231	304	228	312	266	247	141	301	
21-Aug	183	212	219	288	219	258	239	254	167	293	
22-Aug	170	253	232	288	259	217	198	280	151	294	
23-Aug	162	254	275	284	234	237	253	264	161	288	
24-Aug	178	279	241	295	171	273	229	286	228	240	
25-Aug	172	280	231	249	190	281	235	263	245	259	
26-Aug	166	220	163	242	198	263	266	206	225	289	
27-Aug	190	174	128	292	194	252	266	144	156	313	
28-Aug	178	221	163	296	209	258	230	139	157	280	
29-Aug	142	199	144	294	210	216	226	232	176	319	
30-Aug	172	242	151	346	192	260	247	213	165	273	
31-Aug	184	252	150	315	136	269	286	284	193	261	
1-Sep	172	285	157	299	147	237	257	287	152	260	
2-Sep	157	259	167	283	178	235	310	251	160	288	
3-Sep	176	303	165	308	168	243	250	274	137	244	
4-Sep	158	314	198	280	212	244	140	280	180	245	
5-Sep	154	245	157	264	222	242	150	312	171	299	
6-Sep	196	277	146	300	222	235	124	319	199	255	
7-Sep	225	329	159	306	178	249	141	292	172	212	
8-Sep	258	301	145	319	175	282	219	301	177	207	
9-Sep	316	310	143	302	214	269	200	274	173	223	
10-Sep	285	280	172	295	196	271	172	273	220	229	
11-Sep	280	320	179	333	189	252	92	295	285	238	
12-Sep	256	302	189	324	183	220	180	273	297	273	
13-Sep	248	214	162	312	182	166	206	256	267	291	
14-Sep	241	227	145	380	192	147	141	242	220	260	
15-Sep	234	221	143	285	166	180	162	306	225	219	
16-Sep	234	229	145	282	147	216	131	245	168	370	
17-Sep	253	188	160	214	201	196	209	272	195	333	
18-Sep	239	164	170	342	222	183	160	270	214	326	
19-Sep	230	220	181	372	161	207	159	302	240	365	
20-Sep	158	249	172	329	114	221	214	287	239	343	
21-Sep	216	265	127	314	122	245	236	353	251	384	
22-Sep	191	243	188	301	131	230	227	259	281	359	
23-Sep	241	260	184	239	136	204	251	267	299	424	
24-Sep	220	237	228	288	144	200	287	184	292	388	
25-Sep	221	246	229	329	172	204	311	203	321	443	
26-Sep	266	248	189	365	158	200	261	222	345	404	
27-Sep	259	275	296	230	111	189	234	177	323	402	
28-Sep	160	256	229	235	100	189	231	230	269	317	
29-Sep	227	272	195	188	100	229	284	221	267	277	
30-Sep	254	231	257	193	140	180	235	228	260	304	
1-Oct	242	226	293	240	165	194	268	178	257	323	
2-Oct	231	250	292	237	200	187	242	251	239	352	
3-Oct	285	226	318	299	158	182	234	286	238	420	
4-Oct	291	237	288	210	169	205	267	280	243	274	
5-Oct	230	184	271	198	164	317	333	288	274	214	
6-Oct	182	175	212	221	174	325	300	307	264	236	
7-Oct	229	164	219	279	151	261	292	329	269	296	
8-Oct	237	205	200	276	156	268	298	311	178	211	
9-Oct	285	174	170	283	173	269	337	220	156	254	
10-Oct	280	182	193	300	167	293	326	226	137	233	
11-Oct	269	298	191	287	104	291	310	231	116	174	

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
12-Oct	272	298	243	307	54	327	348	239	140	83	
13-Oct	253	324	280	256	55	342	351	216	98	80	
14-Oct	207	304	234	240	132	260	343	133	138	97	
15-Oct	251	299	174	276	137	233	293	119	131	109	
16-Oct	278	315	156	273	154	258	330	123	118	126	
17-Oct	254	329	176	203	162	215	315	142	131	111	
18-Oct	340	299	243	310	77	245	333	117	158	177	
19-Oct	357	332	277	344	84	222	303	122	201	115	
20-Oct	381	307	297	284	103	243	274	152	233	136	
21-Oct	361	360	307	177	119	283	236	196	195	128	
22-Oct	371	295	279	249	144	279	257	224	180	114	
23-Oct	342	241	239	347	164	350	202	224	237	213	
24-Oct	364	262	234	377	257	276	117	300	284	173	
25-Oct	372	245	203	272	119	295	240	278	283	138	
26-Oct	330	268	204	283	89	379	295	267	248	155	
27-Oct	420	268	199	358	61	383	325	252	286	92	
28-Oct	421	291	231	376	42	446	350	255	249	133	
29-Oct	424	298	291	261	104	432	351	300	226	187	
30-Oct	237	191	273	237	185	447	294	258	302	176	
31-Oct	356	240	218	346	101	464	310	230	295	104	
1-Nov	357	296	226	392	101	454	300	298	277	133	
2-Nov	326	277	272	320	105	353	283	270	280	105	
3-Nov	341	199	178	331	140	355	383	397	283	88	
4-Nov	374	198	146	334	157	448	374	350	284	230	
5-Nov	382	221	206	387	203	467	395	208	292	290	
6-Nov	395	285	162	369	234	350	380	254	293	202	
7-Nov	293	283	165	247	225	218	328	176	299	163	
8-Nov	331	300	280	164	348	367	307	179	279	171	
9-Nov	361	293	289	224	353	439	334	382	295	140	
10-Nov	341	285	304	342	380	292	310	394	368	171	
11-Nov	346	263	272	297	336	292	294	356	392	146	
12-Nov	320	260	210	369	306	268	366	384	349	107	
13-Nov	398	281	207	330	193	361	363	376	358	158	
14-Nov	388	230	213	388	331	426	237	349	357	202	
15-Nov	387	284	257	422	358	388	299	332	366	108	
16-Nov	405	273	275	437	343	364	242	353	404	109	
17-Nov	415	257	270	424	383	340	291	310	384	133	
18-Nov	416	175	217	413	382	385	354	332	345	139	
19-Nov	367	248	243	462	347	449	284	391	252	103	
20-Nov	366	175	180	419	318	455	182	408	377	134	
21-Nov	339	216	249	325	297	353	245	394	379	142	
22-Nov	326	171	259	306	245	443	321	430	408	285	
23-Nov	267	270	237	471	234	445	315	421	424	285	
24-Nov	276	316	231	467	244	372	214	431	342	268	
25-Nov	287	341	146	435	273	420	203	385	369	317	
26-Nov	332	333	125	402	253	312	196	339	367	314	
27-Nov	316	316	128	348	254	270	190	280	357	400	
28-Nov	292	255	255	348	275	291	239	336	316	387	
29-Nov	348	305	307	384	279	306	293	382	373	366	
30-Nov	413	332	274	332	231	366	281	453	434	359	
1-Dec	379	368	321	327	341	351	381	304	412	360	
2-Dec	345	385	300	346	419	235	380	264	429	364	
3-Dec	314	379	322	373	386	177	309	281	425	368	
4-Dec	373	338	314	339	245	285	323	302	446	430	
5-Dec	416	379	256	398	335	295	401	329	444	461	
6-Dec	379	394	253	487	349	240	398	366	442	442	
7-Dec	362	408	233	443	388	263	358	370	407	416	

Average Daily Generation for the Bay d'Espoir Hydroelectric Facility (MW)

Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
8-Dec	400	411	288	439	437	354	388	374	402	434	
9-Dec	357	323	333	392	429	390	368	388	379	415	
10-Dec	406	319	236	435	318	353	392	399	372	435	
11-Dec	380	388	277	432	283	387	363	416	253	394	
12-Dec	296	392	292	356	411	381	348	424	327	249	
13-Dec	270	426	219	453	491	408	349	369	405	326	
14-Dec	364	431	283	400	425	429	390	341	387	394	
15-Dec	393	369	333	328	284	400	402	346	397	334	
16-Dec	386	376	429	304	369	458	394	374	422	259	
17-Dec	393	421	419	316	482	442	377	367	445	402	
18-Dec	381	365	392	251	475	400	362	317	350	297	
19-Dec	326	342	399	264	423	353	415	273	284	304	
20-Dec	380	391	323	280	447	386	414	283	233	382	
21-Dec	413	336	353	276	389	376	425	358	285	403	
22-Dec	377	315	384	229	430	267	385	366	329	401	
23-Dec	368	328	405	181	458	243	353	378	426	411	
24-Dec	373	336	356	285	413	327	455	314	440	430	
25-Dec	312	295	412	286	404	246	468	252	429	459	
26-Dec	285	382	415	371	429	173	388	329	428	333	
27-Dec	364	387	485	390	440	192	409	360	461	325	
28-Dec	398	326	518	433	435	345	410	395	471	361	
29-Dec	439	351	478	419	395	446	355	465	486	339	
30-Dec	414	349	481	317	420	420	333	468	403	340	
31-Dec	401	337	468	400	395	397	465	372	401	324	

Q. Provide three additional LIL Shortfall Analysis runs to address BESS resources, potential hydrological resource constraints at Bay d'Espoir and the life extension of Hydro's thermal generation.

c) One LIL Shortfall Analysis run should be conducted that assumes Holyrood Thermal Generating Station, Stephenville Gas Turbine, and Hardwoods Gas Turbine are not retired, the Avalon CT is in service, and BDE Unit 8 is not in service.

A. **c)** The results of the shortfall analysis for the scenario with Holyrood Thermal Generating Station ("Holyrood TGS"), Stephenville Gas Turbine ("GT"), Hardwoods GT and the Avalon Combustion Turbine ("CT") in service, with Bay d'Espoir ("BDE") Unit 8 not in service, can be seen in Chart 1. Under the Average Case (green line), there would be no unserved energy. Under the Severe Case (blue line), the peak shortfall is estimated to be 120 MW with 19 hours of unserved energy over the period, representing 0.4 GWh of energy shortfall.

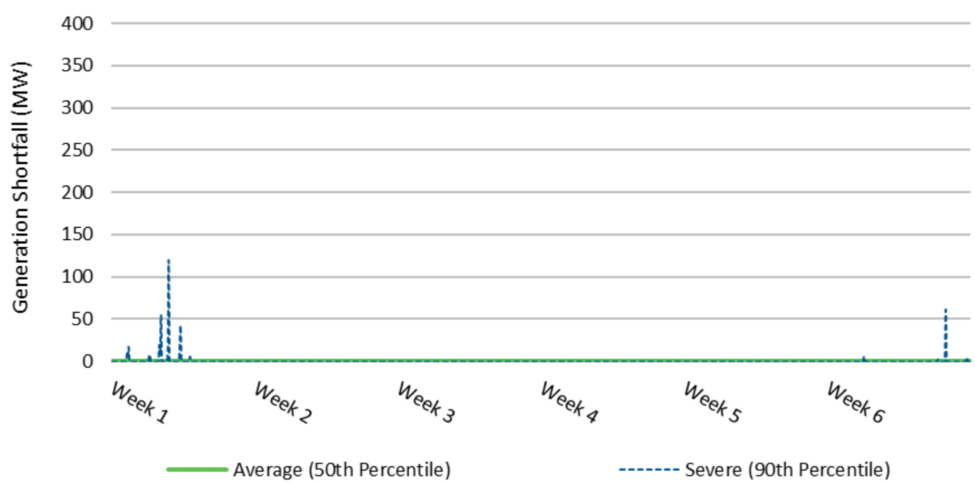

Chart 1: Shortfall over Six Weeks (Slow Decarbonization Load, Holyrood TGS, Stephenville GT, Hardwoods GT, and Avalon CT in service in 2032)

The estimated unserved energy during the peak day of the 2032 reference year for the scenario with Holyrood TGS, Stephenville GT, Hardwoods GT and the Avalon CT in service, with BDE Unit 8 not in service, is presented in Chart 2.

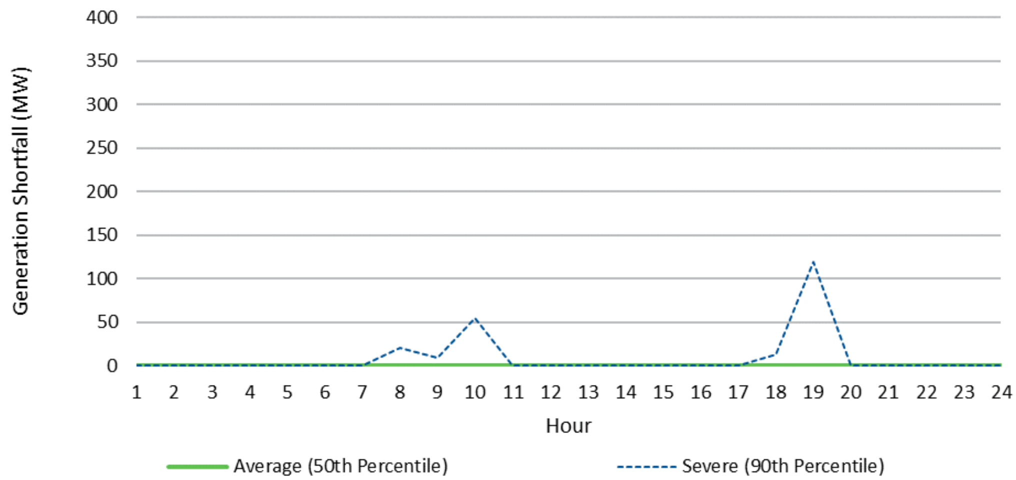

Chart 2: Shortfall on Peak Day (Slow Decarbonization Load, Holyrood TGS, Stephenville GT, Hardwoods GT, and Avalon CT in service in 2032)

Chart 3 depicts the shortfall duration curve for the scenario with Holyrood TGS, Stephenville GT, Hardwoods GT and the Avalon CT in service, with BDE Unit 8 not in service. In the Average Case, there is no unserved energy. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected in one hour.

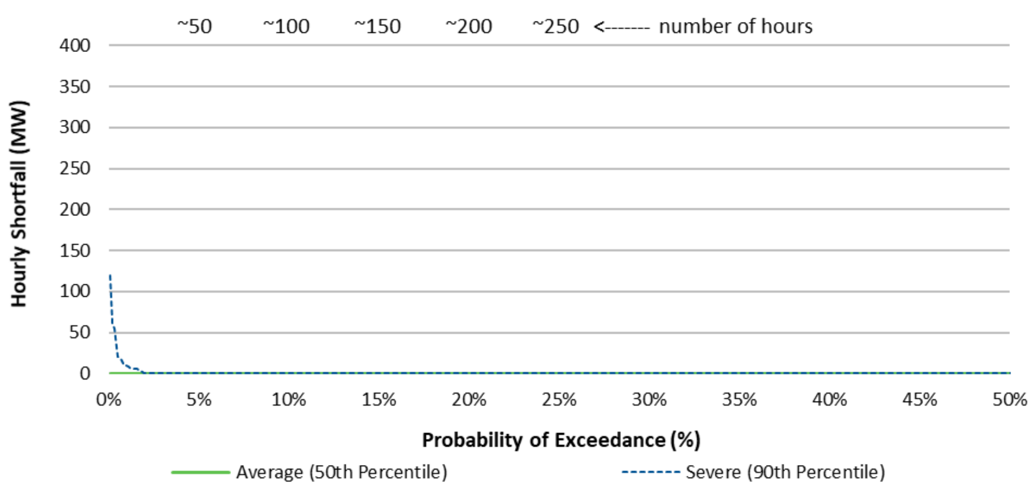

Chart 3: Shortfall Duration Curve (Slow Decarbonization Load, Holyrood TGS, Stephenville GT, Hardwoods GT, and Avalon CT in service in 2032)

For ease of reference, Table 1 summarizes the results presented above.

Table 1: Summary of Shortfall Statistics

	Average Case	Severe Case
Hours of Shortfall	0	19
Total Energy Shortfall (GWh)	0	0.4
Peak Shortfall (MW)	0	120
% of Time Shortfall > 100 MW	0	0.1%

As expected, with the extended operation of Newfoundland and Labrador Hydro's ("Hydro") aging thermal assets, there is no risk of rotating outages in the Average Case. The continuation of Holyrood TGS, Stephenville GT, and Hardwoods GT through to 2030, until new generation can be reliably integrated into the Island Interconnected System with the specific purpose to reduce the risk of loss of load hours, is the basis for the Bridging Plan, which was first presented in the 2022 Reliability and Resource Adequacy Study.[1]

It is important to note that for this scenario, the risk of generation shortfall is eliminated in the Average Case; however, there is still a potential for significant shortfall, and therefore unreliability for customers, in the Severe Case.

This is indicative of a more volatile and less reliable Island Interconnected System due to the high forced outage rates of the Holyrood TGS, Hardwoods GT, and the Stephenville GT, as appropriately reflected due to the age of these assets. Hydro will continue to invest in its thermal assets and make every effort to maintain current levels of reliability while they remain in operation and until new generation can be approved and constructed. Given the age of the assets, however, an increasing level of volatility in their reliability is expected, which has been demonstrated in the annual near-term reliability results when a Holyrood Unit has been unavailable for a portion of the period analyzed.[2,3] Hydro further notes that the federal Clean Electricity Regulations prohibit the operation of the Holyrood TGS beginning in 2035.

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[2] "Reliability and Resource Adequacy Study Review – 2023 Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2023.
[3] "Reliability and Resource Adequacy Study Review – 2024 Near-Term Reliability Report," Newfoundland and Labrador Hydro, November 20, 2024.

Q. Provide an additional capacity expansion model run and LIL Shortfall Analysis which incorporates Newfoundland Power's plans to extend the lives of its gas turbines in 2028 and 2029.[1]

A. For the purpose of this analysis, Newfoundland and Labrador Hydro ("Hydro") assumed that an additional 48 MW of firm capacity exists on the Island Interconnected System. This extra capacity reflects the possibility that Newfoundland Power Inc. ("Newfoundland Power" or "NP") will refurbish its Greenhill and Wesleyville combustion turbines ("CT"). This assumption differs from assumptions used in the analysis completed for the 2025 Build Application and the analysis completed in Hydro's response to part a) of question 2 of this proceeding, which both assume that Newfoundland Power's Greenhill and Wesleyville CTs will be retired in 2030.

The results from Hydro's additional capacity expansion model run and Labrador-Island Link ("LIL") shortfall analysis that incorporates Newfoundland Power's plan to extend the lives of the Wesleyville and Greenhill CTs are detailed below as follows:

- Expansion Plan Analysis for two sensitivities that include Newfoundland Power's CT additions:
  - Scenario 4AK (Fixed Wind Profile, and Include NP CT Additions); and
  - Scenario 4AEK (Fixed Wind Profile, No Batteries, and Include NP CT Additions).
- Shortfall Analysis.
- Two Additional Sensitivities, including Newfoundland Power's CTs as a resource option.
- Reference Case Considerations.
- Transmission Considerations.
- Conclusion.

[1] Newfoundland Power's 2026 Capital Budget Application, 2026-2030 Capital Plan, pages 12 and 19.

Hydro's analysis ultimately found that in every scenario, the initial resource selected as part of the least-cost portfolio of resources remains Bay d'Espoir ("BDE") Unit 8. While the addition of 48 MW of Newfoundland Power's CT as an assumption in this analysis reduces the generation shortfall statistics compared to a scenario where Newfoundland Power's CTs were assumed to have reached their end of life in 2030, neither scenario meets Hydro's shortfall criteria.

In addition, the results continue to demonstrate that both BDE Unit 8 and the Avalon CT continue to represent the least-cost first steps to meeting the Reference Case reliability requirements. Further, the combination of assets provides diversity to the system and a holistic approach to balancing cost, reliability, and environmental considerations. Should Newfoundland Power's proposal to refurbish Newfoundland Power's CTs be approved by the Board of Commissioners of Public Utilities ("Board"), they can help support the Island Interconnected System, including during a LIL shortfall event, provided the appropriate transmission upgrades are implemented.[2]

Expansion Plan Analysis

Newfoundland Power's CTs in Wesleyville and Greenhill, totaling 28 MW of firm capacity, are used to support regional reliability. While Newfoundland Power was previously intending to retire these units,[3] it has since expressed that there may be justification to replace and/or refurbish these units based on long-term regional transmission reliability requirements.[4] Hydro has been working with Newfoundland Power to explore these solutions and to understand the benefits in terms of provincial supply. At the time of the 2024 Resource Adequacy Plan, Hydro included a sensitivity analysis exploring the addition of 75 MW of firm capacity from

[2] Load flow analysis has not been completed for these Expansion Plans. Therefore, it cannot be assumed that the recommended transmission solution of a third line from Western Avalon ("WAV")–Soldier's Pond ("SOP") or the Remedial Action Scheme ("RAS") remains the least-cost solution for these Expansion Plans.
[3] Since 2022, Newfoundland Power's corporate plan has included the retirements of both its Greenhill and Wesleyville CTs, as they are nearing the end of their planned service lives with no plans for refurbishment. Hydro's base assumption in the 2024 Resource Adequacy Plan and the 2025 Build Application was that these units were retiring in 2030.
[4] Newfoundland Power's 2025 Capital Budget Application ("CBA") referenced the forecast refurbishment of the Greenhill and Wesleyville CT over the next five years. Please refer to "Newfoundland Power's 2026 Capital Budget Application," Newfoundland Power Inc., 2026–2030 Capital Plan, p. 1.

Newfoundland Power's CTs,[5] including the transmission requirements to support the Avalon in the event of a LIL shortfall situation for such a scenario.[6]

Through discussions with Newfoundland Power since Hydro's filing of the 2024 Resource Adequacy Plan and the 2025 Build Application, Hydro understands the forecast refurbishment program for the Greenhill and Wesleyville CTs include a potential increase in firm capacity, to 32 MW and 16 MW, respectively, in addition to life extension. As a result, this sensitivity outlined in this response considers an increase in Greenhill and Wesleyville CT's total firm capacity to 48 MW by 2030[7] and assumes their life extension to the end of the modeling horizon (2040). All analyses previously completed for the 2025 Build Application had assumed that Greenhill and Wesleyville CTs were retired in 2030. The amount of capacity forecast to be added to these sites can change based on the results of a joint system planning study being undertaken by the utilities and the outcome of Hydro's recent call for power, which included 150 MW of firm capacity.

For the purposes of this study, the forced outage rates of these units were assumed to be 4.9%[8] to reflect improvements in reliability associated with the replacement of the units. Consistent with the sensitivity analysis included in the 2024 Resource Adequacy Plan, it was assumed that the additional firm capacity exists on the Island Interconnected System, at no cost to Hydro. Therefore, the cost of refurbishing Newfoundland Power's CT is not reflected in the net present value ("NPV"). Following the same naming convention as the analysis completed for the 2024 Resource Adequacy Plan, a new letter "K" was assigned to this sensitivity, and was applied to two sensitivities as outlined in Table 1.

[5] The assumption in the 2024 Resource Adequacy Plan sensitivity was a 25 MW CT operational in 2028, another 25 MW in 2029, and the final 25 MW in 2030. The results of the analysis can be found in "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, sec. 6.2.1.1.13, and 6.2.2.1.12.
[6] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, sec.7.3.2.
[7] While Newfoundland Power plans on the potential refurbishment program for Wesleyville and Greenhill CTs to be completed in 2028 and 2029, Hydro modelled the additional firm capacity to occur in 2030. Modelling these units prior to the retirement of the Holyrood Thermal Generating Station in 2030 would not change the Expansion Plan results, as new capacity resources are not required until post-2030.
[8] A forced outage rate of 4.9% aligns with the forced outage rate of the Holyrood CT. Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, att. 1, for details on Hydro's Forced Outage Rate Methodology.

Table 1: New Expansion Runs

Modelled Sensitivity	Description of Sensitivity
AK	Fixed wind profile to meet firm energy criteria with the addition of the potential Newfoundland Power CTs. All other resource options (i.e., Battery Energy Storage Solution ("BESS") and CTs) are included. Other than fixing the wind profile to meet the firm energy criteria, there are no other resource restrictions in the Plexos model.
AEK	A combination of Sensitivities A, K, and E to determine the impact of excluding batteries in combination with the addition of the potential Newfoundland Power CTs.

These two additional sensitivities were modelled for Scenario 4 (Minimum Investment Required), which represents the scenario requiring the minimum investment (i.e., the least amount of resource additions) based on a high level of LIL reliability (1% LIL bipole EqFOR[9]) that can reasonably be expected in the long term, and the lowest load growth (Slow Decarbonization forecast) that can be reasonably anticipated on the Island Interconnected System.

Wind is the least-cost energy resource (as opposed to solar or small hydro options) to meet the firm energy requirements of the Island Interconnected System. The fixed wind profile was maintained throughout the analysis to ensure that firm energy criteria is being met in each Expansion Plan sensitivity for Scenario 4 (Minimum Investment Required). The firm energy requirement is dependent only on the Island Interconnected System load forecast, and the fixed wind profile is consistent for each load forecast scenario.[10]

Unless otherwise stated, the cost estimates and modeling assumptions are aligned with the additional analysis that was completed for part a) of question 2 of this proceeding.

Results

The results of the Expansion Plan sensitivities are summarized in Table 2 and Table 3, respectively and include the resources built, their firm capacity and firm energy contributions, the cumulative number of units of the resource required in each year (green highlighting indicates the addition of one or more units in that year), and the total firm capacity and firm

[9] Equivalent Forced Outage Rate ("EqFOR").
[10] For more information on firm energy requirements, please refer to "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 4.0.

energy corresponding to the Expansion Plan, reported on an annual basis. Table 2 and Table 3 show the results for 2030 through 2040 for a complete picture of the resources required in the simulation period, particularly when BESS as a resource option is selected. However, the end of the planning horizon remains 2035 as in the 2025 Build Application, to reflect the industry standard of a ten-year planning horizon. No expansion units are required prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets through the Bridging Period.[11] The firm capacity added to the system in each year may be more than the requirement due to the size of the units selected as the least-cost resource options. For example, a 50 MW unit might be the least-cost option to fill a 20 MW requirement. Lastly, the NPV is included for each Expansion Plan sensitivity.

Scenario 4AK (Fixed Wind Profile, and Include NP CT Additions)

As demonstrated in Table 2, Scenario 4AK results in BDE Unit 8 being built in 2031, and a 4-hr 50 MW BESS built in each of 2037, 2039, and 2040, instead of the Avalon CT. The initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.

Table 2: Scenario 4AK Expansion Plan (Fixed Wind Profile, and Include NP CT Additions)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
Battery 4-hr 50 MW	30	0								1	1	2	3
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	242	242	272	294	324	354
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

The NPV of Scenario 4AK is $2.8 billion. However, the costs associated with Newfoundland Power's additional 48 MW of capacity is not included in the Plexos model, which calculates the NPV. Rather, this analysis assumes that an additional 48 MW of firm capacity exists on the Island Interconnected System,[12] compared to the analysis completed for the 2025 Build Application, or the analysis completed in response to part a) of question 2 of this proceeding. Rather, in this

[11] The Bridging Period is defined as the period from the present until 2030, the year in which aging thermal assets are planned to be retired. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.
[12] Newfoundland Power would incur this cost and recovery from customers.

scenario, it is assumed that Newfoundland Power's requirement to refurbish Wesleyville and Greenhill CTs is approved based on regional reliability requirements. **Therefore, this Expansion Plan is not comparable to any other Expansion Plan presented as part of this proceeding based on a NPV comparison.** Additional sensitivity analysis is provided later in this response that considers these resources and their costs, as expansion options for comparison purposes.

Scenario 4AEK (Fixed Wind Profile, No Batteries, and Include NP CT Additions)

Table 3 shows the Expansion Plan for Scenario 4AEK, which results in BDE Unit 8 being built in 2031 and one 94 MW CT in 2037. Compared to Scenario 4A (Fixed Wind Profile) from pat a) of question 2 of this proceeding, this reflects a reduction in total expansion capacity by 2040 of approximately 50 MW, and a delay in the second resource addition of about two years. These results are expected due to the 48 MW increase in Newfoundland Power CT capacity contribution from 2030 onwards. **The initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.**

Table 3: Scenario 4AEK Expansion Plan (Fixed Wind Profile, No Batteries, and Include NP CT Additions)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
CT	94.4	0								1	1	1	1
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	242	242	337	359	359	359
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

The NPV of Scenario 4AEK is $2.9 billion. Once again, the costs associated with Newfoundland Power's additional 48 MW are not included in the Plexos model, which calculates the NPV. Rather, this analysis assumes that an additional 48 MW of firm capacity exists on the Island Interconnected System,[13] compared to the analysis completed for the 2025 Build Application, or the analysis completed for part a) of question 2 of this proceeding. **Therefore, this Expansion Plan is not comparable to any other Expansion Plan presented as part of this proceeding based on an NPV comparison.** Additional sensitivity analysis is provided later in this response that considers these resources as expansion options for comparison purposes.

[13] *Supra,* f.n. 12.

While the Expansion Plan analysis meets the firm energy criteria and the probabilistic planning criteria, the analysis is limited when considering the reliability of the Island Interconnected System, which faces most of its supply shortage risk during the winter period, should a prolonged loss of the LIL bipole occur. As seen in the Planning Reserve Margin results summarized in the 2025 Build Application,[14] the Island Interconnected System reserve margin and the associated capacity requirements are highly dependent on the reliability of the LIL. Even if the LIL consistently has a LIL bipole EqFOR towards the bottom end of the analyzed range (1%), there is still the risk of an extended LIL bipole outage due to line icing or other failure modes. As a result, it is important to deterministically assess an extended outage of the LIL and the associated risk of supply shortfall events. This analysis is provided in the section below.

Shortfall Analysis

The extended outage scenario assumes the LIL is unavailable for six weeks[15] during the coldest period of the year (i.e., January and February). The LIL extended outage is intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line; however, the extended outage scenario could generally apply to any prolonged outage event. There is a risk that such an outage could have a duration lasting longer than six weeks.

The analysis was completed on a probabilistic basis[16] and results are presented as 50th and 90th percentiles representing average and severe scenarios. The amount of shortfall is defined as the amount of load shedding required to restore to a minimum regulating reserve of 70 MW.[17] The average and severe shortfall cases are described as follows:

- **Average Case (50th Percentile):** Represents a generation shortfall that reflects a combination of average probabilistic outcomes, such as typical weather and unit availability, that would be expected to be exceeded 50% of the time in the analysis.

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[14] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 5.1, Table 2.
[15] Hydro used the output of the assessments completed by Haldar in combination with the information provided in the Emergency Response and Restoration Plan as the basis for considering the potential length of a significant outage of the LIL. Please refer to "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 5.2.
[16] The probabilistic analysis considers 2,400 random combinations of weather-driven loads, unit outage profiles, and renewable generation.
[17] Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, sec. 5.1.5.

- **Severe Case (90th Percentile):** Represents a generation shortfall that reflects a combination of severe probabilistic outcomes, such as severe weather and poor unit availability, that would be expected to be exceeded 10% of the time in the analysis.

This analysis does not consider On-Island transmission constraints but generation (supply) constraints only. **It is assumed in this analysis that the transmission system reinforcements to permit Off-Avalon generation to get to the load centre on the Avalon have been implemented prior to 2032.**[18]

Three charts, showing both Average and Severe Cases (as defined above), are presented for each of the above-noted combinations. The three charts illustrate the following:

a) Hourly generation shortfall in MW over the full six-week LIL outage in the 2032 winter period;

b) Hourly generation shortfall in MW over the peak day of the 2032 winter period; and

c) Duration curves showing the shortfall amount (in MW) for every hour over the six-week period. The data is ordered from highest to lowest, and the probability of exceedance is calculated based on the rank of every hour. The approximate number of hours corresponding to each vertical gridline is shown at the top of each plot.

The shortfall analysis was performed for the Expansion Plans identified in Scenarios 4AK and 4AEK, which are the same in the 2032 reference year. As Chart 1 demonstrates, under the Average Case (green line), unserved energy would be expected to occur in 95 hours over the six-week period, representing 6.0 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 219 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 324 MW with 279 hours of unserved energy over the period, representing 24 GWh of energy shortfall.

[18] *Supra,* f.n. 2.

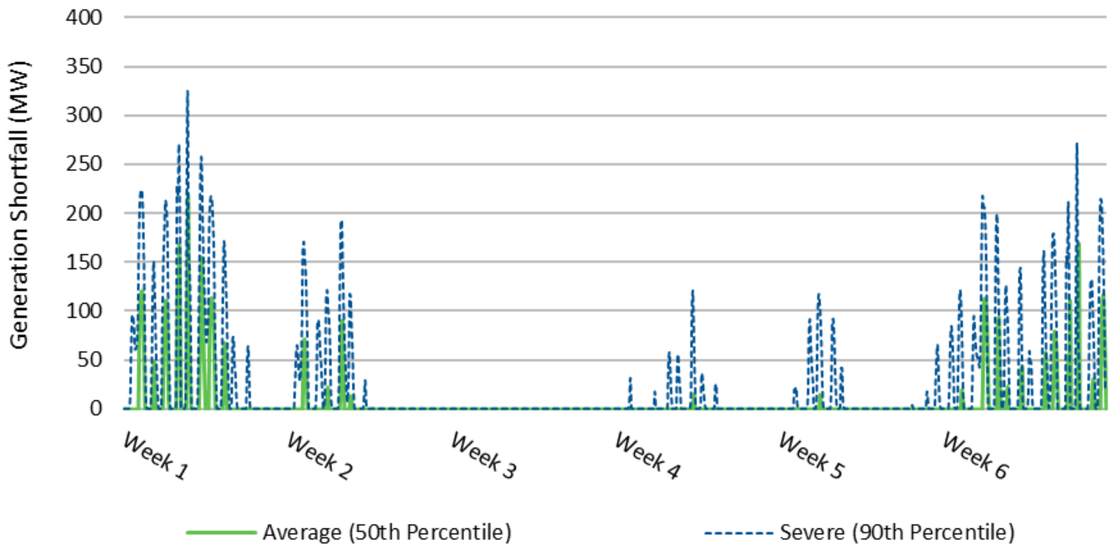

Chart 1: Shortfall over Six Weeks (Scenarios 4AK (Fixed Wind Profile, and NP CT Additions)/4AEK (Fixed Wind Profile, No Batteries, and NP CT Additions))

The estimated unserved energy during the peak day of the 2032 reference year can be seen in Chart 2.

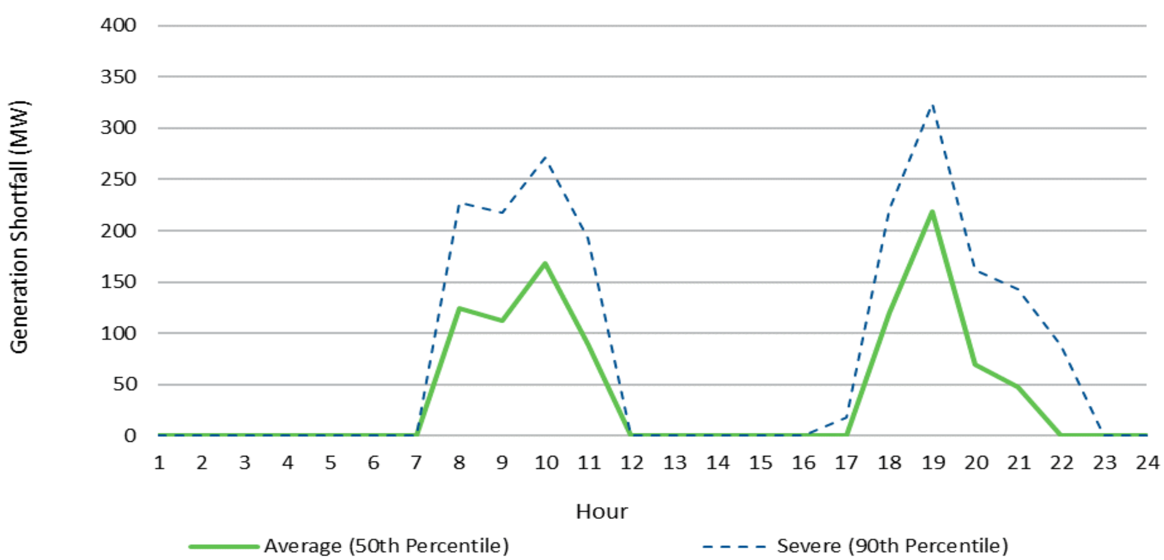

Chart 2: Shortfall on Peak Day (Scenarios 4AK (Fixed Wind Profile, and NP CT Additions)/4AEK (Fixed Wind Profile, No Batteries, and NP CT Additions))

Chart 3 depicts the shortfall duration curve for Scenarios 4AK and 4AEK. In the Average Case (green line), a supply shortfall of over 100 MW occurs in approximately 2.3% of the time. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 9.5% of the time.

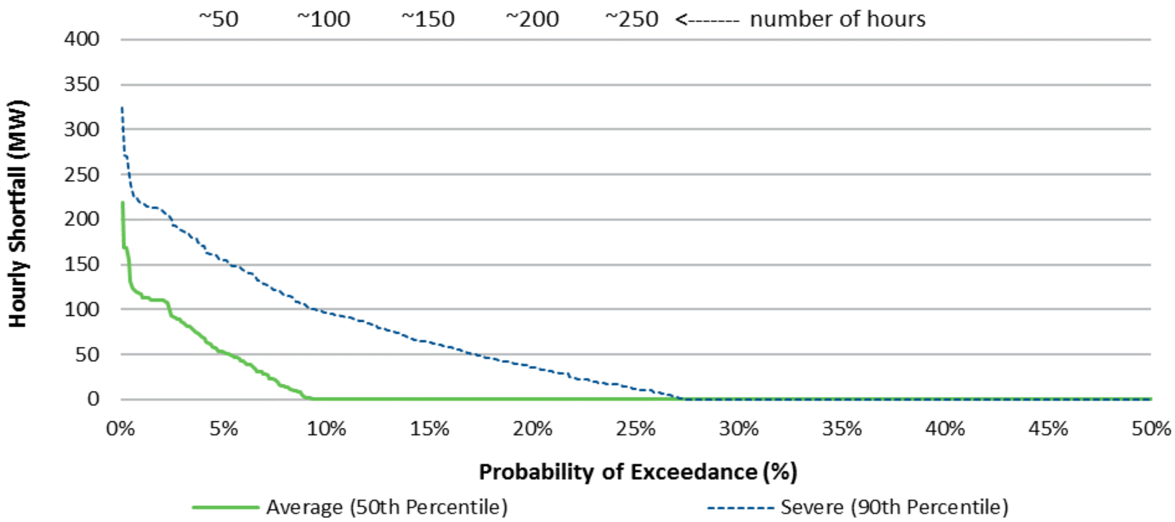

Chart 3: Shortfall Duration Curve (Scenarios 4AK (Fixed Wind Profile, and NP CT Additions)/4AEK (Fixed Wind Profile, No Batteries, and NP CT Additions))

Table 4 and Table 5 illustrate the comparison of the scenarios under the Average and Severe conditions, respectively. In addition, the shortfall statistics that were provided in the 2025 Build Application for Scenario 4AEF (Fixed Wind Profile, No Batteries, and Limit CTs), where it was assumed that both Wesleyville and Greenhill CTs are retired, is included for comparison purposes.[19]

Table 4: Comparison of Shortfall Statistics Under Average Case

Load Scenario	Slow Decarbonization	Slow Decarbonization	Delta
Expansion Plan Scenario	4AEF	4AK; 4AEK	
Hours of Shortfall	142	95	-47
Total Energy Shortfall (GWh)	10	6	-4
Peak Shortfall (MW)	256	219	-37
% of Time Shortfall > 100 MW	4.3%	2.3%	-2.0%

[19] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.3.

Table 5: Comparison of Shortfall Statistics Under Severe Case

Load Scenario	Slow Decarbonization	Slow Decarbonization	Delta
Expansion Plan Scenario	4AEF	4AK; 4AEK	
Hours of Shortfall	351	279	-72
Total Energy Shortfall (GWh)	35	24	-11
Peak Shortfall (MW)	358	324	-34
% of Time Shortfall > 100 MW	14.2%	9.5%	-4.7%

The reduction in unserved energy is consistent with the additional capacity available from Newfoundland Power's Greenhill and Wesleyville CTs. **While the addition of 48 MW of Newfoundland Power's CTs reduces the shortfall statistics compared to a scenario where Newfoundland Power's existing CTs were assumed to have reached their end of life in 2030, neither scenario meets the shortfall criteria**. To ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a previously demonstrated level in the case of a LIL shortfall event, advancing the Avalon CT from 2035 to 2031 is required, as demonstrated in the Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan.[20]

It is also important to note that this analysis assumes that the transmission system reinforcements to permit Off-Avalon generation to get to the load centre on the Avalon have been implemented prior to 2032.[21] Further discussion on the transmission requirements is included later in this response.

<u>Additional Sensitivity Analysis</u>

Additional Expansion Plan sensitivities were conducted with the Newfoundland Power CT refurbishment included as a resource option, instead of assumed already included on the system as per the previous analysis in this response. To complete this additional analysis, two sensitivities were assessed:

- **Sensitivity 1:** Same as Scenario 4AK (Fixed Wind Profile, and Include NP CT Additions); however, the costs of the Newfoundland Power CTs, as provided in Newfoundland

[20] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 6.2.2.
[21] *Supra,* f.n. 2.

Power's 2026 CBA, are input into the Plexos model, and the model selects the least cost resources to meet the Island Interconnected System probabilistic capacity criteria.

- **Sensitivity 2:** Same as Scenario 4AEK (Fixed Wind Profile, No Batteries, and Include NP CT Additions); however, the costs of the Newfoundland Power CTs, as provided in Newfoundland Power's 2026 CBA, are input into the Plexos model, and the model selects the least cost resources to meet the Island Interconnected System probabilistic capacity criteria.

Results

Sensitivity 1

Sensitivity 1 includes costs based on Newfoundland Power's high-level estimate of $2,500/kW, and operations and maintenance ("O&M") costs equivalent to the other CT options.[22]

As demonstrated in Table 6, Scenario 4AK results in BDE Unit 8 being built in 2031, Newfoundland Power's CTs required in 2035, and a 4-hr 50 MW BESS built in each of 2037, 2039, and 2040, instead of the Avalon CT. **The initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.**

Table 6: Scenario 4AK Expansion Plan (Fixed Wind Profile, and Include NP CT Additions as an Option)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
NP CT	48	0						1	1	1	1	1	1
Battery 4-hr 50 MW	30	0								1	1	2	3
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	290	290	320	342	372	402
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

The NPV of Scenario 4AK is $2.9 billion.

[22] Fixed O&M was estimated at $20.57/kW annually, and variable O&M was estimated at $6.17/MWh. Both values are escalated annually based on Hydro's corporate O&M assumptions.

Sensitivity 2

Table 7 shows the Expansion Plan for Scenario 4AEK, which results in BDE Unit 8 being built in 2031, Newfoundland Power CTs in 2035 and one 94 MW CT in 2037. **The initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.**

Table 7: Scenario 4AEK Expansion Plan (Fixed Wind Profile, No Batteries, and Include NP CT Additions as an Option)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
NP CT	48	0						1	1	1	1	1	1
CT	94.4	0								1	1	1	1
Wind 100 MW	22	350	1	3	3	4	4	4	4	4	5	5	5
Firm Capacity (MW)			22	220	220	242	242	290	290	385	407	407	407
Firm Energy (GWh)			350	1050	1050	1400	1400	1400	1400	1400	1750	1750	1750

The NPV of Scenario 4AEK is $3.0 billion.

In both Scenario 4AK and 4AEK, the Newfoundland Power CT was selected after a resource that is more expensive on a $/kW basis. The reason for this is the size of the resource. If the Newfoundland Power CTs were to be built in 2031, the model would have to pair it with another more expensive resource to fill the capacity gap. It is less costly to build the larger BDE Unit 8 first, since its capacity will ultimately be needed anyway.

Newfoundland Power's cost estimate for refurbishing Wesleyville and Greenhill CTs is considered high-level at this point and could very well increase once they undergo formal Association for the Advancement of Cost Engineering classified cost estimates. To provide a "book-end" scenario reflecting the higher end of the range of potential costs, it is useful to consider the Expansion Plan runs completed in Hydro's response to part a) of question 2 of this proceeding, which included a new stand-alone 47 MW CT resource option. The cost of that resource could be considered representative of a high-end range of the cost to refurbish and extend the life of both Wesleyville and Greenhill CTs. In Scenario 4A (Fixed Wind Profile), this 47 MW CT was not selected as part of the least-cost portfolio. The NPV of Scenario 4A (Fixed Wind Profile) is $3.1 billion.

In all analyses to date in response to this question, BDE Unit 8 has been consistently selected as the initial resource as part of the least-cost portfolio of resources. It is also important to note that **neither scenario presented in part a) of question 2 of this proceeding, nor the scenarios presented in response to this question, meet all the Island Interconnected System resource planning criteria.[23] The addition of BDE Unit 8 and Newfoundland Power's CTs, in combination with retiring Hydro's aging thermal assets, is insufficient to mitigate a supply shortfall of less than 100 MW;[24] and therefore is in violation of Hydro's Shortfall Criteria. As outlined in Hydro's response to part a) of question 3 of this proceeding, BESS would be less effective than the Avalon CT in a shortfall scenario. Therefore, Hydro continues to recommend advancing the Avalon CT from 2035 to 2031, to ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a manageable level.**

Reference Case Requirements

It is also important to acknowledge that the Minimum Investment Required Expansion Plan does not meet the reliability requirements of the Reference Case or Expected Case.[25] Rather, the Minimum Investment Required Expansion Plan is the first step to meeting these requirements. To provide a fulsome response to this question, Hydro has simulated two additional Expansion Plan scenarios under expected load and LIL reliability conditions, with Newfoundland Power's CTs included as a resource option using the cost information provided in their CBA. The results are presented in Table 8 and Table 9, respectively.

As demonstrated in Table 8, Scenario 1AK results in both BDE Unit 8 and the Avalon CT being built in 2031, Newfoundland Power's CTs in 2032, and a 4-hr 50 MW BESS built in each of 2033, 2035, 2036, 2037, 2038, two in 2039, and 2040. Although less expensive on a $/kW cost basis compared to other resource options, as stated above, Newfoundland Power's cost estimate for refurbishing Wesleyville and Greenhill CTs are considered high-level at this point and may increase as the estimates are further refined.

[23] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, sec. 1.0.
[24] Newfoundland Power was able to rotate 100 MW during the 2014 loss-of-load event.
[25] Scenario 1 (Reference Case): Represents the expected case, or the scenario that incorporates assumptions that are considered most reasonable at this time by combining the Reference Case load forecast for the Island Interconnected System and the expected LIL bipole EqFOR of 5%. The expected case has historically formed the foundation of the recommended Expansion Plan.

Table 8: Scenario 1AK Expansion Plan (Fixed Wind Profile, NP CT Expansion Option)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
CT	141.6	0		1	1	1	1	1	1	1	1	1	1
NP CT	48	0			1	1	1	1	1	1	1	1	1
Battery 4-hr 50 MW	30	0				1	1	2	3	4	5	7	8
Wind 100 MW	22	350	2	4	4	4	5	5	5	6	6	6	6
Firm Capacity (MW)			44	384	432	462	484	514	544	596	626	686	716
Firm Energy (GWh)			700	1400	1400	1400	1750	1750	1750	2100	2100	2100	2100

The NPV of Scenario 1AK is $5.0 billion.

Table 9 presents the Expansion Plan for Scenario 1AEK, reflecting the expansion when batteries are excluded from the resource options. This Expansion Plan results in both BDE Unit 8 and the Avalon CT being built in 2031, Newfoundland Power's CTs in 2032, an additional standalone 94.4 MW CT in 2033, and an additional 141.6 MW CT in 2037.

The NPV of Scenario 1AEK is $5.1 billion.

Table 9: Scenario 1AEK Expansion Plan (Fixed Wind Profile, No Batteries, NP CT Expansion Option)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BDE Unit 8	154.4	0		1	1	1	1	1	1	1	1	1	1
CT	141.6	0		1	1	1	1	1	1	2	2	2	2
NP CT	48	0			1	1	1	1	1	1	1	1	1
CT	94.4	0				1	1	1	1	1	1	1	1
Wind 100 MW	22	350	2	4	4	4	5	5	5	6	6	6	6
Firm Capacity (MW)			44	384	432	562	548	548	548	712	712	712	712
Firm Energy (GWh)			700	1400	1400	1400	1750	1750	1750	2100	2100	2100	2100

These results demonstrate that both BDE Unit 8 and the Avalon CT continue to represent the least-cost first steps to meeting the Reference Case reliability requirements. Should Newfoundland Power's proposal to refurbish the Newfoundland Power CTs be approved by

the Board, they can help support the Island Interconnected System, including during a LIL shortfall event, provided the appropriate transmission upgrades are implemented.[26]

As demonstrated by TransGrid Solutions Inc.'s Study and reported in the 2024 Resource Adequacy Plan, On-Avalon generation has a significant benefit to system reliability during a LIL shortfall event.[27] **If the proposed capacity of the Avalon CT were to be displaced by generation outside of the Avalon Peninsula, there would be an increased shortfall during a LIL bipole outage. In addition, analysis completed in support of the RAS has demonstrated that a reduction in supply on the Avalon Peninsula would likely drive a requirement for increased reactive support in the Western Avalon region.**

Note On Transmission Requirements

The amount of power transferred between BDE and SOP is dependent on LIL imports, the amount of Avalon generation dispatched and the magnitude of Avalon load. There are currently transmission constraints that limit the amount of BDE–SOP power transfer during a LIL bipole outage ("LIL Shortfall Scenario") that are defined based on specific 230 kV line contingencies that can cause thermal overloads and/or abnormal low voltages. During a LIL Shortfall Scenario, there is more power flow between BDE–SOP because there are no LIL imports being delivered to SOP, and the Avalon load must be supplied from Off-Avalon resources. The increased BDE–SOP flows during high load conditions increase the likelihood of exceeding the existing transmission constraint limits. It is worth noting that the **transmission constraints are not a concern during normal operation when the LIL is in service and would not restrict Hydro's ability to transfer any Off-Avalon generation (i.e., BDE Unit 8) to the Avalon.**

The proposed Avalon CT is intended to be dispatched to offload the BDE–SOP transmission system during a LIL Shortfall Scenario with the objective of serving more customer load on the Avalon while avoiding the transmission constraint limits. **A reduction in the Avalon CT capacity would put more strain on the BDE–SOP transmission system during a LIL Shortfall Scenario and would likely lead to a requirement for incremental transmission system upgrades.**

[26] *Supra,* f.n. 2.
[27] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, sec. 7.3.

Conclusion

The Avalon CT will solve two problems: it will provide the needed supply to the Island Interconnected System and alleviate strain on the BDE–SOP transmission during a LIL Shortfall Scenario. Whereas the addition of BDE Unit 8 is a renewable resource that remains the initial resource selected as part of the least-cost portfolio of resources and has the ability to support Hydro's annual maintenance outage requirements. Both resource options are expected to adhere to the final Clean Electricity Regulations and provide strength in the diversity of the asset combination of thermal and hydro resources. In combination, these resource options continue to provide a holistic approach to balancing cost, reliability, and environmental considerations to meet the needs of the Island Interconnected System.

Q. Bates White filed an expert assessment of the 2024 Resource Adequacy Plan with the Board on August 30, 2024, providing over sixty action items for Hydro to consider before moving forward in the resource planning process. In the Bates White Report, they reiterate their recommendation for Hydro to consider employing competitive solicitation for its energy and capacity needs. Please detail Hydro's response to this recommendation.

A. Bates White Economic Consulting, LLC ("Bates White"), in its August 30, 2024 report, suggested that Newfoundland and Labrador Hydro ("Hydro") pursue *". . . competitive solicitation for energy and capacity in a variety of ways that would allow for direct competition between supply options such as PPA extensions, third-party offers, and utility development options."*[1] Bates White noted that Hydro had not included market purchases as a supply resource option, and while referencing Hydro's statement that it *"has not secured any capacity support from external markets for a duration longer than one month and does not have a basis to assume that such solutions would be available to meet long-term planning requirements"* further noted that it might be useful for Hydro to invite offers from parties in other provinces and markets to offer energy and capacity in a competitive solicitation.

Hydro confirms that it has explored external market purchases and has also initiated a Request for Expression of Interest ("RFEOI") process to investigate third-party supply options. As summarized below, there are no feasible external market solutions that could support Hydro's firm supply requirements in the study period. There is potential for third-party solutions to be developed on the Island Interconnected System to meet supply requirements. However, timelines for the feasibility assessment, front-end engineering, detailed design, and development of such solutions would be extensive.

The Island Interconnected System has access to three potential markets when considering firm imports via the Maritime Link—Nova Scotia, New Brunswick, and New England. Both Nova

[1] "Assessment of Newfoudland and Labrador Hydro's 2024 Resource Adequacy Plan," Bates White Economic Consulting, LLC, August 30, 2024, p. 30.

Scotia Power and New Brunswick Power issued Integrated Resource Plans in 2023, addressing their plans to meet capacity requirements.[2,3] As discussed in Hydro's most recent Near-Term Report, in August 2024, Hydro confirmed with both Nova Scotia Power and New Brunswick Power that acquiring a firm import contract during the winter period for reliability is not feasible for either utility in the near term. However, the potential markets and constraints will continue to be assessed annually. This confirmation does not preclude opportunities on a short-term (spot market) basis for firm capacity or non-firm energy to meet capacity or energy requirements for the Island Interconnected System.[4]

The market in New England has an annual forward capacity market auction, which determines the capacity market for the fourth year out in the future. Considering the long lead time to build the required capacity in Newfoundland and Labrador, this capacity market planning horizon is not compatible with the planning requirements for the reliability of the Island Interconnected System.[5]

Hydro has previously addressed the limiting factors of firm imports from these markets, particularly in the near term, in the 2024 Resource Adequacy Plan and later in the technical conference presentation and the resulting Requests for Information. Delivery of imported energy via the Maritime Link has associated transmission constraints, which significantly limit the viability of off-island generation for the provision of firm capacity on the Island Interconnected System.[6]

With regards to solicitation of on-island firm capacity and energy, Hydro discussed the viability of competitive solicitation for a number of energy and capacity options, including a combustion turbine ("CT"), in its Technical Conference #2 presentation on October 2, 2024.[7] Hydro has also

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[2] "Powering A Green Nova Scotia, Together – 2023 Evergreen Integrated Resource Plan – Updated Action Plan and Roadmap," Nova Scotia Power Inc., August 8, 2023, https://www.nspower.ca/docs/default-source/irp/2023-action-plan-and-road-map.pdf?sfvrsn=bcd3c747_1.
[3] "2023 Integrated Resource Plan – Pathways to a Net-Zero Electricity System," New Brunswick Power Corporation, https://www.nbpower.com/media/1492536/2023_irp.pdf.
[4] "Reliability and Resource Adequacy Study Review – 2024 Near-Term Reliability Report," Newfoundland and Labrador Hydro, November 20, 2024, sec. 3.5.1, pp. 29–30.
[5] *Supra,* f.n. 4.
[6] Please refer to "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. B, sec. 5.4.1.1, pp. 51–53.
[7] "2024 Resource Adequacy Plan – Technical Conference #2 – Issue #4: Resource Supply Options," Newfoundland and Labrador Hydro, October 2, 2024, slide 22.

issued an RFEOI process on July 9, 2025, for the supply of energy and capacity that, in combination, can provide for up to 150 megawatts (MW) of firm capacity and up to 500 gigawatts (GWh) of firm energy.

Responses to that RFEOI may range from the procurement of renewable intermittent generation to proposals from proponents offering to build turnkey CTs.

As outlined in Hydro's response to CA-NLH-066 of the *Reliability and Resource Adequacy Study* proceeding, consistent with common utility practice, Hydro does not intend to own or operate wind generation. As Hydro does not have the operational experience or resources necessary to construct or operate assets of this nature, doing so would present significant operational and financial risk. Hydro believes that its resources are better utilized in planning and executing its proposed projects for capacity expansion.

Procurement of energy through an open and competitive expression of interest process for the Island Interconnected System is consistent with common industry practice and will ensure that energy is procured in a manner that is consistent with least-cost reliable service.

Hydro has been in active discussion with proponents, including existing and potential Industrial customers, and there is no immediate opportunity for firm capacity on the Island Interconnected System. Further, in-service dates for any solutions proposed in the RFEOI process would not only be dependent on regulatory and construction timelines, but also on feasibility assessment work. This assessment work would include system impact studies to identify transmission system upgrade requirements. In addition, feasibility assessments would be required to ensure the robustness of solutions for considerations of safe and reliable operation. Investigations into fuel supply plans for CTs or operational and technological reviews for alternative solutions would be required. Commercial aspects would also need to be defined. All of these considerations would need to be addressed before front-end engineering design ("FEED") work for any such solution could be effectively advanced.

When considering the solutions proposed by the Hydro 2025 Build Application, feasibility has been confirmed, and system impact studies and FEED work are complete. These projects are therefore unique in that they are fully defined and ready for detailed engineering and construction.

Bay d'Espoir Unit 8 and Avalon CT have been demonstrated to be the least-cost, reliable and environmentally sound solutions and are positioned to meet Hydro's recommended Minimum Investment Required Expansion Plan. The approval of these projects would provide increased clarity and allow for Hydro to begin the effective evaluation, advancement, and optimization of emerging solutions such as battery banks and those from the RFEOI process. This critical work will help ensure reliability and resource adequacy in consideration of the Reference Case and future supply requirements.

Q. The Bates White Report identified an inconsistency in the calculation of management reserve.[1] Please confirm the inconsistency in the calculation of management reserve identified in the Bates White Report and recalculate that Net Present Values calculations of the capacity expansion modeling runs accounting for the corrected management reserves.

A. Newfoundland and Labrador Hydro ("Hydro") has recalculated the escalation and Interest During Construction ("IDC") values for both the Bay d'Espoir Unit 8 ("BDE Unit 8") and the Avalon Combustion Turbine ("Avalon CT") to include the Management Reserve values for the P85 cost sensitivity, as requested by the Board of Commisioners of Public Utilities.

For ease of reference, Table 1 presents the Authorized Budget (P85) cost estimates used in the 2025 Build Application and the recalculated P85 cost estimates[2] in 2024 CAD dollars.

Table 1: Resource Option Cost Estimates (Authorized Budget (P85))[3]

Resource	Rated Capacity (MW)	Firm Capacity (MW)	Authorized Cost of Firm Capacity ($/kW) 2025 Build Application	Authorized Cost of Firm Capacity ($/kW) Additional Analysis	Difference ($/kW)	Difference (%)
BDE Unit 8	154.4	154.4	6,990	7,184	+194	+2.8
Avalon CT	141.6	141.6	6,295	6,454	+159	+2.5

Please refer to Hydro's response to question 2 of this proceeding for more information on the impact this modification has on the Expansion Plan sensitivity, as well as the net present value.

The addition of IDC and escalation increased total authorized cost by less than 3% overall. Although Hydro recognizes this adjustment may lead to more accurate predictions of the project's financial market impacts, Hydro does not believe it is necessary to alter its current

[1] Paragraphs (95) through (97) and Table 8, pages 46-48.
[2] For the purposes of this analysis, the P85 values for both the hydro and thermal options were recalculated as per Bates White Economic Consulting, LLC's suggestion to include escalation and IDC in the Management Reserve.
[3] Note that year and resource-specific escalation factors are applied to these costs within the Plexos model to reflect expected changes in capital cost over time.

budget. Unlike Contingency, which is to cover known unknowns and is built into the project cost and schedule baseline, Management Reserve is for strategic risks (i.e., unknown unknowns) that were identified in risk planning. These costs are included in the total project funding estimate, but are not considered part of the project’s planned cash flow and are outside the project baseline costs. Therefore, Hydro’s budget calculations exclude the Management Reserve from escalation and IDC until and unless the unknown unknown arises and the related Management Reserve is utilized. Hydro will continue to monitor and estimate best practices going forward.

Q. The Bates White Report identified discrepancies between the load forecast figures presented in the Application and numerical data presented in the 2023 and 2024 Load Forecast reports.[1] Please address the load forecast discrepancy.

A. Newfoundland and Labrador Hydro ("Hydro") made an error within the 2024 Load Forecast Report when updating the 2024 Slow Decarbonization load forecast based on the feedback received from Bates White Economic Consulting, LLC ("Bates White"). As a result, two rows in Schedule 3, Appendix A, Attachment 1, Table 4 of the 2024 Load Forecast Report were not updated, resulting in the discrepancy noted by Bates White. Hydro can confirm that all graphs and text in the 2024 Load Forecast Report are otherwise correct, and that the correct forecast was used for all subsequent modeling work. Hydro has provided the corrected Table 4 as Attachment 1 to this response.

Further, the Bates White Report[2] indicated that Hydro did not incorporate several recommendations Bates White had made in their review of the 2023 Load Forecast Report, stating:

> While the 2024 load forecast addresses our general recommendations for timely updates, it does not incorporate several recommendations made in our review of the 2023 Load Forecast.[3]

However, this is not accurate.

The impacts of Bates White's recommendations on the 2024 Slow Decarbonization load forecast compared to the 2023 Slow Decarbonization load forecast were addressed in detail as presented in Technical Conference #1 on September 17, 2024.[4] These changes were

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[1] Paragraphs (31) through (34) and Figure 2, pages 21-23.
[2] "Expert Report of Vincent Musco and Collin Cain," Bates White Economic Consulting, LLC, June 26, 2025 ("Bates White Report").
[3] *Supra,* f.n. 2, sec. III. B., para. 25, p. 19.
[4] "2024 Resource Adequacy Plan – Technical Conference #1: Load Forecast/Reliability Planning Criteria," Newfoundland and Labrador Hydro, September 17, 2024.

incorporated into Hydro's 2024 Load Forecast Report. An overview of what was covered during Technical Conference #1 is summarized below.

Provincial Population Growth

In regard to population growth, the Bates White Report recommended that Hydro should *"Assess the impacts on the load forecast of flat or falling population, consistent with low provincial population growth scenarios evaluated by Statistics Canada."*[5]

In Hydro's 2024 Slow Decarbonization scenario, Hydro considered Bates White's recommendation from the 2023 Load Forecast review, while also accounting for current provincial trends. In the 2024 Slow Decarbonization scenario, the forecasted population grows from 543,000 to 546,000 over the next ten years to 2035, with a total growth of 0.5%, which is less than the 2023 Slow Decarbonization scenario that included total population growth of 1.1%. The 2024 Slow Decarbonization scenario takes into consideration the near-term trend of population growth, with the population forecasted to peak in 2028 and then decline annually through to 2035. In 2024, Statistics Canada provided ten population forecast scenarios to provide a plausible and sufficient broad range of projected numbers to take account of the uncertainties inherent in any projection exercise. Hydro's population forecast provided by the provincial government falls within the range of Statistics Canada population scenarios and provides a provincial perspective on local demographics.

Figure 1 compares the Newfoundland population forecasts and the June 2024[6] Statistics Canada's low growth forecast, which is the lowest of the ten scenarios for comparison.

[5] *Supra,* f.n. 3.
[6] "Population Projections for Canada, Provinces and Territories," Statistics Canada, https://www150.statcan.gc.ca/n1/en/catalogue/91-520-X.

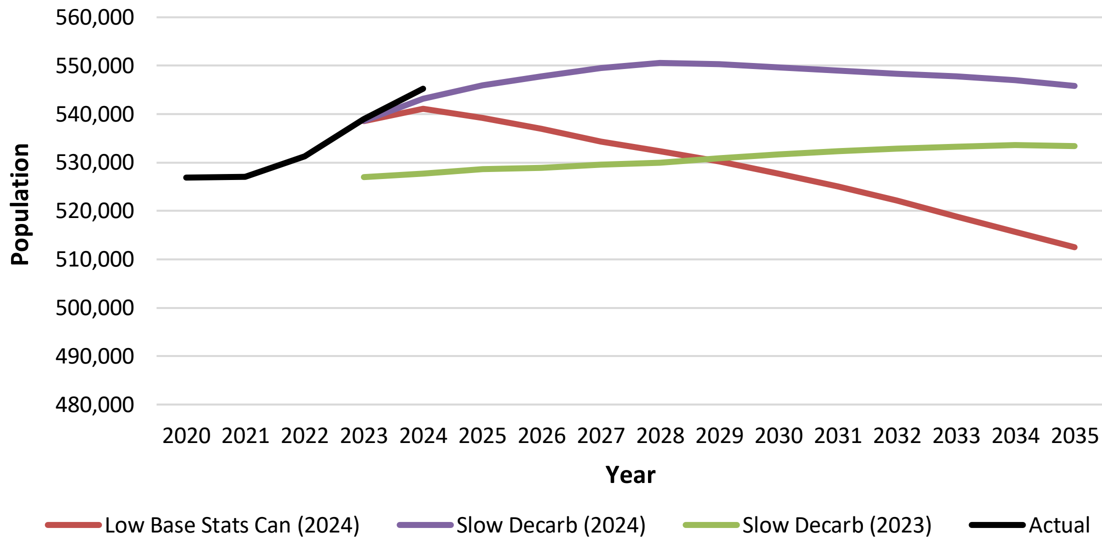

Figure 1: Newfoundland Population Forecast Comparison

As discussed in Technical Conference #1, **the population input by itself does not impact the overall peak demand in Hydro's load forecast model.**[7] The Island system's peak load is driven by home heating, and historically, a reduction in population has not directly led to a reduced number of households/customers and demand requirements. In fact, historically, the number of customers has continued to increase. Regardless, the 2024 Slow Decarbonization load forecast has almost no total growth over the ten-year period (0.5%), and forecasts less growth than the 2023 Slow Decarbonization load forecast, in line with Bates White's recommendation.

Industrial Load Growth

In regard to industrial load growth, the Bates White Report recommended that Hydro should *"Supplement the Slow Decarbonization case with an assessment of impacts from lower or flat industrial load growth."*[8]

The 2024 Slow Decarbonization load forecast includes only 10 MW of industrial growth over the ten-year time period. All other Industrial customers included in this load forecast scenario are existing Industrial customers, for which the demand requirements are essentially flat over the ten-year time horizon. The 2024 Slow Decarbonization load forecast has lower industrial growth

[7] *Supra*, f.n. 4, slides 12–16.
[8] *Supra,* f.n. 3.

than the 2024 Reference Case load forecast and the 2023 Slow Decarbonization load forecast. Hydro completes an annual assessment of Industrial customers and large load requests, and the 2024 Slow Decarbonization load forecast includes 10 MW of industrial growth as a prudent inclusion based on the current activity and investment being made in the province. Also discussed in Technical Conference #1, **10 MW does not have a material impact on the overall forecasted demand, rather represents approximately 0.5% of the 2035 total demand.**

<u>Impacts on Oil to Electric Conversion</u>

In regard to oil-to-electric conversion, the Bates White Report recommended that Hydro should:

> Provide detail on the assumptions and associated forecast impacts of oil-to-electric conversion programs, the ability of customers to retain oil heating systems for backup, and the potential impact of electric backup (i.e., resistive heating) to heat pumps.[9]

Hydro provided details on the assumptions and associated forecast impacts of oil-to-electric conversion programs, the ability of customers to retain oil heating systems for backup, and the potential impact of electric backup (i.e., resistive heating) to heat pumps on the 2024 versus 2023 Slow Decarbonization load forecast during Technical Conference #1.[10] In addition, Section 3.2.1.3 Decarbonization and Electrification (Utility Sales) of the 2024 Load Forecast Report in the 2025 Build Application discusses the oil-to-electric program and outlines the takeCHARGE program that requires participants to remove their oil tank to meet eligibility requirements. The eligibility requirements for the oil-to-electric program are created by the provincial government, and the rebates are funded by the provincial government.

<u>Electric Vehicle Growth Projections</u>

In regard to electric vehicle ("EV") growth, the Bates White Report recommended that Hydro should *"Detail the assumptions underpinning the EV growth projections, including the timing and extend to which growth in charging infrastructure will be achieved."*[11]

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[9] *Supra,* f.n. 3.
[10] *Supra*, f.n. 4, slides 21–24.
[11] *Supra,* f.n. 3.

Details on the assumptions underpinning the EV growth projections were discussed during Technical Conference #1.[12] In addition, the most recent EV assumptions are included with the 2024 Load Forecast report in the 2025 Build Application.[13]

Lastly, in their report, Bates White stated:

> …we find the more significant issue is that the load forecasting is uncertain, it changes year-to-year….for this reason, we find that close monitoring of load trends is essential to determine what future path actually is more likely going forward.[14]

As noted in Hydro's load forecast reports, the Island Interconnected System long-term load forecast is updated annually, includes consideration of a broad range of potential future outcomes to reflect future uncertainty, and each annual update incorporates the most recent information and provincial trends.

[12] *Supra*, f.n. 4, slides 17–20.
[13] "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 3, app. A, att. 2.
[14] *Supra,* f.n. 2, sec. III. B., para. 34, p. 23.

Table 4: 2024 Planning Load Forecasts
Island Interconnected System Load Summary[10]

Slow Decarbonization Case	**2024 [11]**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Total Island Requirements (GWh)	7,955	8,049	8,142	8,127	8,179	8,274	8,319	8,346	8,371	8,453	8,520	8,603
Growth Rate . . . (%)		1.2	1.2	-0.2	0.7	1.2	0.5	0.3	0.3	1.0	0.8	1.0
Island Customer Coincident Peak Demand (MW)	1,691	1,706	1,739	1,747	1,758	1,782	1,791	1,804	1,817	1,832	1,847	1,865
Growth Rate . . . (%)		0.9	1.9	0.5	0.6	1.4	0.5	0.7	0.7	0.8	0.9	1.0

Reference Case	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Total Island Requirements (GWh)	7,959	8,067	8,197	8,215	8,346	8,510	8,595	8,648	8,702	8,802	8,912	9,035
Growth Rate . . . (%)		1.4	1.6	0.2	1.6	2.0	1.0	0.6	0.6	1.1	1.2	1.4
Island Customer Coincident Peak Demand (MW)	1,691	1,707	1,742	1,757	1,778	1,807	1,819	1,837	1,855	1,881	1,902	1,928
Growth Rate . . . (%)		0.9	2.1	0.8	1.2	1.6	0.6	1.0	1.0	1.4	1.1	1.3

Accelerated Decarbonization Case	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Total Island Requirements (GWh)	7,971	8,108	8,254	8,310	8,632	9,077	9,216	9,334	9,458	9,574	9,713	9,970
Growth Rate . . . (%)		1.7	1.8	0.7	3.9	5.2	1.5	1.3	1.3	1.2	1.4	2.6
Island Customer Coincident Peak Demand (MW)	1,691	1,716	1,756	1,773	1,803	1,923	1,942	1,972	2,007	2,036	2,067	2,115
Growth Rate . . . (%)		1.4	2.3	1.0	1.7	6.7	1.0	1.5	1.7	1.4	1.5	2.3

[10] Exclusive of transmission losses and station service loads.
[11] 2023 Island customer coincident peak demand is an actual.

Q. Hydro has filed an application for Life Extension of BDE Unit 7. If the decision to construct BDE Unit 8 were to be delayed beyond what has been proposed in the Application, would Hydro see merit in including a capacity increase to BDE Unit 7 as studied in the 2024 Resource Adequacy Plan?[1] As part of the response, please provide the information that led Hydro to not include the uprate of BDE Unit 7 as referenced by Hatch in its 2024 Uprate Report.

A. Newfoundland and Labrador Hydro ("Hydro") does not see merit in including a capacity increase to Bay d'Espoir ("BDE") Unit 7, due to:

- **i.** The impacts the increase would have on overall system hydrology and efficiency;
- **ii.** Project delays for both the Life Extension of Unit 7 and the construction of Unit 8; and
- **iii.** The associated costs and potential reliability impacts.

These reasons are discussed further below.

Impact on System Hydrology and Efficiency

The Uprate Report prepared by Hatch Ltd ("Hatch") in June 2024 stated that any increase in the capacity of Unit 7 may directly impact the capacity available from Unit 8, but suggested further study of the overall system. Hatch noted:

> Since there is a finite amount of hydraulic capacity available in the Bay d'Espoir system to be utilized for the purposes of additional generating capacity, it may be more cost-effective to utilize that hydraulic capacity in a new purpose-built Unit #8 rather than through a modification of Unit #7.[2]

[1] Paragraphs (95) through (97) and Table 8, pages 46-48.
[2] "Uprate Report," Hatch Ltd, June 27, 2024, sec. 3.1.4, p. 6 provided in "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, att. 2.

The Hydrology and Feasibility Study for the Potential Bay d'Espoir Hydroelectric Generating Unit No. 8, completed by Hatch and filed with the 2025 Build Application,[3] confirmed that the optimized generating capacity increase at the BDE plant is 150.1 MW with the addition of BDE Unit 8. This is marginally less than the 154.4 MW capacity of BDE Unit 8 because, although the Vista model utilizes the full capacity of BDE Unit 8, it optimizes the total BDE plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation, resulting from the BDE system being modelled in isolation for the purposes of the study. In reality, through optimization of Hydro's full hydraulic resources, resources can likely be managed to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW. This finding establishes a limit on efficient incremental capacity available in the BDE system, for consideration across both Unit 7 and the planned Unit 8.

Additionally, the Uprate Report identified that an increase in the capacity of Unit 7 may result in less efficient operation over the typical and planned operating range of the unit;[4] resulting in increased water usage in a hydrologically constrained system.

Hydro notes that the addition of Unit 8 itself effectively constitutes an uprating of the BDE system. Hatch confirmed that the maximum incremental capacity available from the system, given hydrological constraints, is approximately 150 MW. Hydro considers the addition of Unit 8 to be the most efficient and optimal method of achieving this uprate, rather than pursuing a modification to Unit 7, which has the potential to impact overall system efficiency and risk delaying the refurbishment of existing capacity.

Project Delays

Pursuing a capacity increase for Unit 7 would require substantial additional engineering and design work to confirm the technical viability of the project and the potential megawatt available in the uprate. This would delay the start of the Unit 7 life extension project by two years, with an anticipated construction schedule spanning two years rather than one due to

[3] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, sch. 1, att. 2.
[4] "Uprate Report," Hatch Ltd, June 27, 2024, sec. 3.1.1, pp. 3–4 provided in "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024), app. C, att. 2.

increased scope, pushing the in-service date from the fourth quarter of 2028 into the fourth quarter of 2031. Hydro's 2023 Condition Assessment concluded that refurbishment of Unit 7 is required by 2029 to ensure its continued reliability. Any delay in refurbishment presents a material risk to system reliability, as an unplanned outage of Unit 7 would remove a critical source of firm capacity from the Island Interconnected System.

As a result of the hydrological constraints previously discussed, an increase in the capacity of Unit 7 would have significant potential to result in a reduction to the capacity of Unit 8. This reduction would necessitate substantial re-engineering of Unit 8 which would further compound delays in the implementation of both projects.

Cost Implications

Delaying the life extension of Unit 7 would have significant cost implications. Construction costs are subject to escalation and increasing market pressure, and delaying the project would increase overall costs. Further, delaying Unit 7 would also delay the integration of Unit 8, due to the additional engineering required for the reduction of Unit 8 capacity and the coordination of site work between the two projects. Each year of delay to Unit 8 results in an estimated $30–$50 million in project costs, in addition to the higher cost of relying on aging thermal generation to maintain supply adequacy.

Ultimately, Hydro weighed the risk to system reliability as a result of the delayed refurbishment of Unit 7 versus the potential for increased capacity by uprating Unit 7, taking into consideration the potential impacts to the overall operation of the BDE system, and concluded that an increase in the capacity of Unit 7 should not be pursued for the reasons detailed above.

In addition to the direct impacts on Units 7 and 8, a decision to pursue an uprate would also affect the broader system. Projects identified for completion in Hydro's five-year capital plan could be impacted through changes in sequencing, outage planning, and resourcing.

The hydrologic limitations of the BDE system, the efficiency considerations, the impact to the capacity of Unit 8, the risks to system reliability from delaying refurbishment, the significant cost impacts of deferring both Unit 7 and Unit 8, and the additional re-engineering required if Unit 8 were reduced in capacity, all support proceeding with the life extension of Unit 7.

Hydro's recommended approach is to proceed with the life extension of Unit 7, which includes pursuing efficiency improvements in the new turbine runner design, to maintain system reliability in the near-term while enabling the full capacity development of Unit 8. This approach ensures optimal usage of the available hydrology of the BDE system to provide an additional 150 MW of fully dispatchable capacity, and mitigates the cost and reliability impacts of delays in either project.

Q. In the Application, Hydro is using a composite depreciable life of 35 years for the Avalon CT and 60 years for BDE Unit 8. What was the rationale for selecting these depreciable lives? In the response, include a discussion on how these depreciable lives align with those used in Hydro's most recent depreciation study, and the assumed 50- year design life in Hydro's Basis of Design report, dated March 25, 2025.[1] Explain the justification for variances.

A. The composite useful life of 35 years for a combustion turbine ("CT") and 60 years for Bay d'Espoir Unit 8 ("BDE Unit 8") were based on a prior estimate of composite depreciable life for these assets. These estimates were used for the depreciation estimate in the calculation of the estimated incremental revenue requirement for each asset in Newfoundland and Labrador Hydro's ("Hydro") 2025 Build Application.

In Hydro's most recent Depreciation Study,[2] the estimated depreciation rate for gas turbines is 2.06% or approximately 49 years, plus a composite removal rate of 0.14%.[3] The 49-year composite life aligns with the assumed 50-year design life in Section 7.1 of Hydro's Basis of Design report.[4] Restating the depreciation to reflect the updated composite depreciable life plus removal costs would result in an annual revenue requirement of $91.2 million, or $5.5 million less than the $96.7 million estimated in the 2025 Build Application using a composite life of 35 years.

The estimated depreciation rate for hydraulic generation in the most recent Depreciation Study is 1.38% or 72 years, plus a composite removal rate of 0.04%.[5] Restating the depreciation to reflect the updated composite depreciable life plus removal costs would result in a revenue

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[1] Additional Information filed by Hydro, June 13, 2025, Attachment 3.
[2] "2017 General Rate Application," Newfoundland and Labrador Hydro, rev. July 4, 2018 (originally filed July 28, 2017), vol. II, exh. 11. Approved in Board Order No. P.U. 16(2019).
[3] Overall annual depreciation estimate equals (2.06% + 0.14%) = 2.20% or equivalent to 45 years.
[4] Please refer to "Avalon Combustion Turbine Basis of Design," Newfoundland and Labrador Hydro, March 25, 2025, sec. 7.1, pp. 6–7 filed with the Board of Commissioners of Public Utilities as Attachment 3 of "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Documents Placed on the Record – Hydro's Reply," Newfoundland and Labrador Hydro, June 13, 2025.
[5] Overall annual depreciation estimate equals (1.38% + 0.04%) = 1.42% or equivalent to 70 years.

requirement of $80.8 million, or $2.5 million less than the $83.3 million estimated in the 2025 Build Application using a composite life of 60 years.

The actual depreciation impact may vary from the estimate of the CT and BDE Unit 8 and will depend on the cost of the individual units of property that comprise these generation additions. In Hydro's 2025 Build Application, Hydro provided an illustrative estimate for revenue requirement, noting that the ultimate customer rate impact depends largely on any rate mitigation decisions for the post-2030 period, which are unknown at this time. The estimate using the composite useful lives of 35 years and 60 years assumed in the 2025 Build Application provides a reasonable estimate of depreciation and revenue requirement impacts.

Q. In the Application, Hydro has stated that the impact to customer rates associated with the Avalon CT and BDE Unit 8 projects will not be fully known in advance of 2030. Please provide a pro-forma incremental customer rate impact analysis over the 2030 to 2040 period for each project, on a per kWh and percentage basis assuming the proposed capital expenditures are approved in full and the current rate mitigation plan continues beyond 2030 but the BDE Unit 8 and Avalon CT project costs are not rate mitigated.

A. The pro-forma incremental customer rate impact analysis over the 2030 to 2040 period for each project, on a per kWh and percentage basis, is included in Attachment 1. As requested by the Board of Commissioners of Public Utilities ("Board"), Attachment 1 assumes the current rate mitigation plan continues beyond 2030 and the proposed capital expenditures are approved in full, but not subject to rate mitigation.

As shown in Attachment 1, rate increases are higher for the 2029 to 2032 period, when assets are being put into service, than in future years in the analysis. This is especially true when looking at the total rate increase if both projects are approved and put into service according to the current estimated schedule. As customer affordability is of primary importance, scenarios that consider rate smoothing alternatives may be more palatable. This calculation is based on the specific assumptions requested by the Board with respect to rate mitigation policy; however, actual rate mitigation in the post-2030 period and, therefore, customer rates, may differ materially and will depend on future decisions of the Government of Newfoundland and Labrador. In addition, these estimates are based on assumptions made at a point in time, which have been noted in Attachment 1; actual results may differ from those assumptions used.

Bay d'Espoir Unit 8

Pro-forma Incremental Customer Rate Impact ($000)[1]

		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost[2]	**1,079,221**											
Depreciation		-	-	17,987	17,987	17,987	17,987	17,987	17,987	17,987	17,987	17,987
Net Book Value		-	1,079,221	1,061,234	1,043,247	1,025,260	1,007,273	989,286	971,299	953,312	935,325	917,338
Operating Cost		-	-	3,252	3,333	3,417	3,502	3,590	3,679	3,771	3,866	3,962
Operating Escalation		-	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Revenue Requirement												
Return		-	31,297	62,073	61,030	59,987	58,943	57,900	56,857	55,814	54,770	53,727
Depreciation		-	-	17,987	17,987	17,987	17,987	17,987	17,987	17,987	17,987	17,987
Operating Costs		-	-	3,252	3,333	3,417	3,502	3,590	3,679	3,771	3,866	3,962
Incremental Revenue Requirement		**-**	**31,297**	**83,312**	**82,350**	**81,390**	**80,433**	**79,477**	**78,523**	**77,572**	**76,623**	**75,676**
Estimated Incremental Rate Impact (¢/kWh)			0.47	1.26	1.25	1.23	1.22	1.20	1.19	1.18	1.16	1.15
Estimate Avg. Annual Rate (¢/kWh)[3]		19.32	19.89	20.48	21.08	21.70	22.34	23.00	23.68	24.38	25.10	25.84
Total Avg. Rate (¢/kWh)		19.32	20.36	21.74	22.33	22.94	23.56	24.21	24.87	25.56	26.26	26.99
Avg. Annual Rate Increase		-	5.4%	6.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.8%	2.8%	2.8%

[1] Numbers may not add due to rounding.

[2] Based on P85 costs as included in Newfoundland and Labrador Hydro's ("Hydro") 2025 Build Application.

[3] Assumes continuation of rate mitigation plan excluding the revenue requirement impact of Bay d'Espoir Unit 8. Assumes annual rate increases on July 1 of each year of:
2026 - 7.00%
2027 - 3.10%
2028 onward - 2.95%

Rate increases for 2026 and 2027 are estimated based on Newfoundland Power Inc.'s ("Newfoundland Power") forecast rate increases after customer rate smoothing provided in "Approval of Compliance with Order No. P.U. 3(2025) and Customer Rates, Rules and Regulations, effective July 1, 2025," Newfoundland Power Inc., April 17, 2025, sch. 2, p. 8, Table 4. Rate increases from 2028 onward are estimated assuming a 2.25% increase attributed to Hydro and a 0.7% increase for Newfoundland Power.

Other Assumptions:
In-service date - December 31, 2031.
O&M escalation of 2.5% per year.
Average annual rate 2025 - 15.71¢/kWh.
Depreciable Life - 60 Years
Incremental Weighted Average Cost of Capital - 5.80%
Estimated incremental rate impact assumes a $66 million change in revenue requirement equals approximately 1 cent change in domestic rates.

Avalon Combustion Turbine

Pro-forma Incremental Customer Rate Impact ($000)[1]

		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost[2]	**891,415**													
Depreciation		-	-	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469
Net Book Value		-	891,415.00	865,946	840,477	815,008	789,539	764,070	738,601	713,132	687,663	662,194	636,725	611,256
Operating Cost		-	-	3,732	3,825	3,921	4,019	4,119	4,222	4,328	4,436	4,547	4,661	4,777
Operating Escalation		-	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Revenue Requirement														
Return		-	25,851	50,963	49,486	48,009	46,532	45,055	43,577	42,100	40,623	39,146	37,669	36,191
Depreciation		-	-	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469	25,469
Fuel		-	-	16,551	16,965	17,389	17,824	18,269	18,726	19,194	19,674	20,166	20,670	21,187
Operating Costs		-	-	3,732	3,825	3,921	4,019	4,119	4,222	4,328	4,436	4,547	4,661	4,777
Incremental Revenue Requirement		**-**	**25,851**	**96,715**	**95,745**	**94,788**	**93,843**	**92,912**	**91,995**	**91,091**	**90,202**	**89,328**	**88,468**	**87,624**
Estimated Incremental Rate Impact (¢/kWh)		-	0.39	1.47	1.45	1.44	1.42	1.41	1.39	1.38	1.37	1.35	1.34	1.33
Estimate Avg. Annual Rate (¢/kWh)[3]		18.23	18.77	19.32	19.89	20.48	21.08	21.70	22.34	23.00	23.68	24.38	25.10	25.84
Total Avg. Rate (¢/kWh)		18.23	19.16	20.79	21.34	21.91	22.50	23.11	23.74	24.38	25.05	25.73	26.44	27.17
Avg. Annual Rate Increase		-	5.1%	8.5%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.8%

[1] Numbers may not add due to rounding.

[2] Based on P85 costs as included in Newfoundland and Labrador Hydro's ("Hydro") 2025 Build Application.

[3] Assumes continuation of rate mitigation plan excluding the revenue requirement impact of Avalon Combustion Turbine. Assumes annual rate increases on July 1 of each year of:
2026 - 7.00%
2027 - 3.10%
2028 onward - 2.95%

Rate increases for 2026 and 2027 estimated based on Newfoundland Power Inc.'s forecast rate increases after customer rate smoothing provided in "Approval of Compliance with Order No. P.U. 3(2025) and Customer Rates, Rules and Regulations, effective July 1, 2025," Newfoundland Power Inc., April 17, 2025, sch. 2, p. 8, Table 4. Rate increases from 2028 onward estimated assuming 2.25% increase attributed to Hydro and 0.7% increase for Newfoundland Power.

Other Assumptions:
In-service date - December 31, 2029.
O&M escalation of 2.5% per year.
Fuel Escalation of 2.5% per year.
Average annual rate 2025 - 15.71¢/kWh.
Depreciable Life - 35 Years
Incremental Weighted Average Cost of Capital - 5.80%
Estimated incremental rate impact assumes a $66 million change in revenue requirement equals approximately 1 cent change in domestic rates.

Q. As part of the Reliability and Resource Adequacy Settled Issues dated March 11, 2025, Schedule A to the Settled Issues List has identified the following studies that would be filed with the Board throughout 2025 as part of the continuous planning associated with current and future reliability and resource adequacy of the Island Interconnected System:[1]

- The Final Lower Churchill Project Operational Study - Q2, 2025
- Evaluation of BESS for Frequency Support - Q4, 2025
- Evaluation of a Remedial Action Scheme for the Avalon 230 kV Corridor - Q4, 2025
- Transmission Expansion Feasibility Study - Q4, 2025
- Marine Terminal Station FEED - Q3, 2025
- CDM Potential Study - Q2, 2025
- ELCC Study - Q4, 2025
- 2025 Load Forecast Update - Q4, 2025

Provide an update on the status of these studies, including an update as to the month that each report is anticipated to be filed.

A. As agreed within the Settlement Agreement,[2] Newfoundland and Labrador Hydro ("Hydro") intends to file each of these studies within 45 days of receipt of the final report, with exceptions as noted, to support the reference case requirements to be identified within the 2026 Resource Adequacy Plan.

Hydro has provided an update for each estimated filing date within Table 1.

[1] "Application, Schedule 2, Attachment 1.
[2] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 2.

Table 1: Filing Dates

Study	Estimated Completion Date[3]	Status Update	Estimated Filing Date[4]
The Final Lower Churchill Project Operational Study	Complete	Study filed on August 10, 2025.	Filed
Evaluation of a Remedial Action Scheme ("RAS") for the Avalon 230 kV Corridor	Complete	Final report received August 2025.[5]	October 2025
Evaluation of BESS[6] for Frequency Support	Q4 2025	Study and final report remain on schedule.	February 2026
Transmission Expansion Feasibility Study	Q4 2025	Study and final report remain on schedule.[7]	February 2026
Marine Terminal Station FEED[8]	TBD	To date, Hydro has completed the necessary condition assessment work to determine the scope of a potential future project. Additional engineering and planning would be required to complete FEED on this project. Please refer to Hydro's response to question 2 of this proceeding for more information. Hydro will provide an update in its semi-annual report to the Board of Commissioners of Public Utilities ("Board") and parties in Q4 2025.	TBD[9]
CDM[10] Potential Study	Complete	Will be filed as part of the 2026–2030 Joint Utility ECDM[11] Plan.	December 2025
ELCC Study	Q3 2025	Study and final report remain on schedule.	November 2025
2025 Load Forecast Update: Island Interconnected System	Q3 2025	Study and final report remain on schedule.	November 2025

[3] Date as per the Settlement Agreement, unless the study is complete.
[4] This date is subject to change depending on a variety of factors. Estimated filing dates assume final consultant reports are received as outlined in Schedule A to the Settlement Agreement.
[5] In the Settlement Agreement, Hydro had indicated that it would file this report along with the Transmission Expansion Feasibility Study after its completion in Q4 2025. In the interest of regulatory efficiency, Hydro will advance the filing of its RAS Study to provide more information on the solution for transmission constraints within the Avalon 230 kV corridor. Hydro has received the final study from its consultant, TransGrid Solutions Inc., which has concluded that the RAS can be implemented in concert with Bay d'Espoir Unit 8 and the Avalon Combustion Turbine to eliminate the need for additional transmission upgrades in the Minimum Investment Required Case.
[6] Battery Energy Storage System ("BESS").
[7] While transmission line construction will not be required in support of the proposed projects in the 2025 Build Application, Hydro will continue with its commitment to work with a consultant on the Transmission Feasibility Study to refresh the cost estimate.
[8] Front-end engineering design ("FEED").
[9] As is the practice with FEED documentation, applicable FEED documentation will be filed with a future capital application for the Marine Terminal Station, if necessary, and not stand-alone reporting, as outlined in the Settlement Agreement.
[10] Conservation and Demand Management ("CDM").
[11] Energy, Conservation and Demand Management ("ECDM").

As studies progress, estimated filing dates are subject to change. Hydro will continue to keep the Board informed of any changes with regard to timelines of the studies above within its semi-annual report. The semi-annual report will provide information on all ongoing work related to planning for the reliability and resource adequacy for the Island Interconnected System. The first semi-annual report will be filed in Q4 of 2025, with the following reports filed in Q2 and Q4 of each year thereafter.

Q. Based on the timing of the Transmission Expansion Feasibility Study, currently not expected until Q4, 2025, please address the considerations associated with (i) a possible separation of the process for the review of the two projects and (ii) an earlier review of the proposed Avalon CT.

A. In the 2024 Resource Adequacy Plan Settlement Agreement, Newfoundland and Labrador Hydro (“Hydro”) had indicated that it would file its report on the Evaluation of a Remedial Action Scheme (“RAS”) for the Avalon 230 kV Corridor, along with the Transmission Expansion Feasibility Study, after its completion in the fourth quarter of 2025. The RAS Study final report has been received by Hydro ahead of schedule. In the interest of regulatory efficiency, Hydro will advance the filing of its RAS Study to the Board of Commissioners of Public Utilities and parties in the coming weeks.

The conclusions contained in the report prepared by Hydro’s consultant, TransGrid Solutions Inc., include the following:

- The RAS is confirmed to be an effective solution in a Labrador-Island Link Shortfall scenario. It enables increased flows to the Avalon Peninsula to meet Hydro's criteria; and
- The RAS can be implemented in concert with Bay d’Espoir Unit 8 (“BDE Unit 8”) and the Avalon Combustion Turbine (“Avalon CT”) to eliminate the need for additional transmission upgrades in the Minimum Investment Required Case.

Based on the above conclusions, Hydro will not need to pursue the construction of a new transmission line in the corridor between Bay d’Espoir and Soldiers Pond in the near term. Rather, Hydro will begin technical design and estimation work for the implementation of the RAS. Hydro has engaged Newfoundland Power Inc. on this work, and preliminary discussions are underway for a collaborative solution. While transmission line construction will not be required in support of the proposed projects in the 2025 Build Application, Hydro will continue to work with a consultant on the Transmission Feasibility Study to refresh cost estimates, as committed.[1]

Timely review and approval of both proposed resource additions, BDE Unit 8 and the Avalon CT, are crucial to meeting customer demand through the planning period and to avoiding additional costs associated with project delays and the continued operation of aging thermal resources. To that end, Hydro does not oppose changes in the regulatory process that would improve process efficiency and enable the timely approval of one or both resource options. Hydro is therefore not opposed to the possible separation of the process for review of the two projects, nor an earlier review of the proposed Avalon CT, provided that these changes would not constitute a pause or delay in the review process of BDE Unit 8. Hydro reiterates that the analysis performed for response to this Request for Information ultimately found that in every scenario, the initial resource selected as part of the least-cost portfolio of resources remains BDE Unit 8.

It is also important to note that neither solution on its own addresses the constraints identified in the *Reliability and Resource Adequacy Study Review* proceeding. These projects together form part of Hydro's recommended Expansion Plan as the first step to meet Island Interconnected System reliability, enable the retirement of aging thermal assets, and provide the additional benefit of diversity of supply, further reinforcing reliable capacity to the system.

It should be noted that a separation or earlier review of the Avalon CT would not provide efficiencies from an execution perspective. Hydro has two independent project teams in place that are progressing both projects in parallel. It is also not the interaction between BDE Unit 8 and the Avalon CT that is concerning if one asset or the other is reviewed or approved earlier. The concern is with respect to delays in the approval of either project and the resulting risk of delay in the retirement of units at the Holyrood Thermal Generating Station. Such a delay could result in annual costs of over $120 million,[2] in addition to costs associated with project delays in the range of $30 million to $50 million per project, per year. Hydro believes it is important to consider these costs when contemplating changes in process that could delay the approval of either project, when both are required to meet system reliability. Furthermore, considering the

[1] A new transmission line between Western Avalon Terminal Station and Soldiers Pond Terminal Station was previously identified as a potential upgrade requirement. This transmission line was estimated to cost approximately $150 million.
[2] "Reliability and Resource Adequacy Study Review – Holyrood Thermal Generating Station Capital Plan Refresh," Newfoundland and Labrador Hydro, March 7, 2025, att. 1.

long project timelines for major projects, delays specifically to the BDE Unit 8 project will have a substantial effect, cost delays, and re-planning for the multi-year long-term capital plan for both sustaining capital and other major projects (i.e., Bay d'Espoir Unit 7 Refurbishment, Penstocks, etc.).

Q. Hydro has indicated that deviations from the anticipated application schedule will increase costs and extend the in-service date and that approval of both projects is required by Q4, 2025. Please address the impact for each of the projects if approval is not received by year end, including whether an application for additional early execution work would be anticipated.

A. Upon review of the current progress and execution strategy for both the Avalon Combustion Turbine Project and the Bay d'Espoir Unit 8 Project early execution scopes, Newfoundland and Labrador Hydro ("Hydro") anticipates that approximately two to three months of activities can be continued under the existing approved early execution budgets beyond the fourth quarter of 2025, into the first quarter of 2026. This assumes the procurement commitments estimated in the original early execution budgets do not materially increase.

If approval by the Board of Commissioners of Public Utilities is delayed beyond this timeframe, an additional early execution application would be required. The budget of an additional early execution application would depend on the anticipated length of the delay. As the project progresses through detailed engineering and procurement and into the construction phase, it is anticipated that the magnitude of costs will be much higher than the initial early execution application. Hydro anticipates requesting approval for expenditures, including cost recovery, within a second early execution application.

Any delay in approval introduces risk to both projects, particularly from a vendor confidence standpoint. In today's competitive marketplace, any uncertainty about whether a project will proceed can deter bidders—especially those who are busy or focused on more certain opportunities—from participating in the procurement process. Further, full approval of the projects would give Hydro the authority to make timely decisions to mitigate any project risks.

Therefore, Hydro believes that the most efficient and least-cost process for customers to mitigate further cost escalation due to schedule delays remains approval of the 2025 Build Application in the fourth quarter of 2025. A second early execution application would result in deviation from the 2025 Build Application, to review and evaluate another application, ultimately with the same request for approvals.

Q. In the Application Hydro notes plans for consultation with interested groups including Miawpukek First Nation.[1] Has Miawpukek First Nation or any other indigenous community asserted that Hydro has a constitutional obligation to consult and accommodate its interests in relation to the BDE Unit 8 Project or the Avalon CT projects? If so, please identify the indigenous community and provide details of the scope of work and timelines needed to discharge any such duty.

A. On October 11, 2006, the Newfoundland and Labrador Court of Appeal upheld the decision of the Supreme Court of Newfoundland and Labrador, Trial Division that, notwithstanding the creation and recognition of the Miawpukek Mi'kmaq First Nation ("MFN") under the *Indian Act*, the MFN did not establish that they had an Aboriginal or treaty right under section 35(1) of the *Constitution Act, 1982*.[2] The Court of Appeal's ruling confirmed that the trial judge did not err in considering and applying the evidence before them or in applying the pre-European contact test set out in *R. v. Van der Peet*, 1996 CanLII 216 (SCC), [1996] 2 S.C.R. 507 ("*Van der Peet*"). The appeal was dismissed in its entirety, and leave to appeal to the Supreme Court of Canada was dismissed.

To date, *Drew* has not been overturned by the Newfoundland and Labrador Court of Appeal or the Supreme Court of Canada. Similarly, the *Van der Peet* test still serves as the test for determining section 35(1) rights. The Government of Newfoundland and Labrador's position is that there are no indigenous communities in the region that have a constitutional right to consultation and accommodation. This is applicable to the Bay d'Espoir Unit 8 project and the Avalon Combustion Turbine projects.

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[1] Application, Schedule 4 Appendix C and Schedule 5, Appendix D.
[2] *Newfoundland v. Drew et al*., 2006 NLCA 53 ("*Drew*").