PREPARED FOR THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES OF NEWFOUNDLAND AND LABRADOR

In response to Newfoundland Labrador Hydro's 2025 "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine"

EXPERT ADDENDUM REPORT OF VINCENT MUSCO AND COLLIN CAIN

November 6, 2025

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Abbreviations and defined terms used in report

2024 RAP – 2024 Resource Adequacy Plan

Avalon CT – Avalon Combustion Turbine

Bates White – Bates White Economic Consulting, LLC

BDE – Bay d'Espoir Hydroelectric Power Station

BDE Unit 8 – Bay d'Espoir Unit 8

BESS – Battery Energy Storage Systems

Board – Newfoundland and Labrador Board of Commissioners of Public Utilities

Build Application – Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine

CT – Combustion Turbine

ELCC – Electric Load Carrying Capability

GT – Gas Turbine

Holyrood TGS – Holyrood Thermal Generation Station

Hydro – Newfoundland Labrador Hydro

IIS – Newfoundland Island Interconnected System

LIL – Labrador Island Link

LOLH – Loss-of-load-hours

Newfoundland Power, NP – Newfoundland Power Inc.

NLIS – Newfoundland and Labrador Interconnected System

RAS – Remedial Action Scheme

RFEOI – Request for Expression of Interest

RFI – Request for information

TransGrid – TransGrid Solutions

I. Introduction and background

(1) On March 21, 2025, Newfoundland and Labrador Hydro ("Hydro") submitted an "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine" ("Build Application"), which seeks approval of capital expenditures related to the purchase and installation of the Bay d'Espoir ("BDE") Unit 8 ("BDE Unit 8") and the Avalon Combustion Turbine ("Avalon CT"). The Build Application requests approval to develop, build, own, and operate two new supply resources. First, Hydro seeks approval for BDE Unit 8, with a nameplate capacity of 154 MW at an Authorized Budget[1] of $1.08 billion.[2] BDE Unit 8 is proposed to have an anticipated completion date in 2031.[3] Second, Hydro seeks approval for the 150 MW Avalon CT at an Authorized Budget of $891 million.[4] The anticipated completion date is stated as "late 2029."[5]

(2) Bates White Economic Consulting, LLC ("Bates White") was retained by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board") as an Expert Consultant to assess Hydro's Build Application. On June 26, 2025 Bates White filed an expert report in response to the Build Application ("Bates White June Expert Report").[6] This report provided an assessment of the modeling and planning efforts led by Hydro to determine new resource needs and selections. The review offered in the Bates White June Expert Report was limited to Hydro's planning efforts completed in 2024, and therefore excluded detailed assessments of cost estimates, project schedules, and project management protocols, among other items.[7] In recognition of the findings and conclusions outlined in the Bates White June Expert Report, the following recommendations were offered:[8]

1. Hydro should address and reconcile the potential modeling inconsistency regarding the resource selection identified by Hydro under Scenario 4AEFC.[9]

2. Hydro should conduct capacity expansion model runs relaxing 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.

[1] The Authorized Budget includes base cost estimates, interest during construction, escalation, contingency, and a management reserve. Build Application, Schedule 1, page 21, lines 1 to 2.

[2] Build Application, Schedule 4, page 30, lines 12 to 14.

[3] Build Application, Application, page 3, paragraph 13.

[4] Build Application, Application, page 3, paragraph 14.

[5] Build Application, Application, page 3, paragraph 14.

[6] "Expert Report of Vincent Musco and Collin Cain," June 26, 2025, available at: http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/report/Bates%20White%20Economic%20Consulting%20-%20Expert%20Report%20-%20REDACTED%20-%202025-06-26.PDF ("Bates White June Expert Report").

[7] These and other matters will be focus of forthcoming Bates White reports in reviewing the Build Application.

[8] Bates White June Expert Report, pages 14 and 15, paragraph 13.

[9] Appendix A explains the assumptions associated with each modeling scenario (e.g., "Scenario 4AEFC").

3. Hydro should conduct capacity expansion model runs that include Battery Energy Storage Systems ("BESS") resources of 4-hour and 8-hour duration, assuming Electric Load Carrying Capabilities ("ELCCs") of 60%, using updated capital cost estimates for BESS resources. These runs should be conducted for Scenarios 4AEF, 4AEFC, and 4AEFDH. These model runs will allow for better understanding of the economics of BESS resources relative to BDE Unit 8 and the Avalon CT.

    - Collectively, then, we recommend three additional capacity expansion model runs. In each run, Hydro should address our Recommendations 2 and 3 above. That is, each run should relax the Combustion Turbine ("CT") constraints and BESS prohibition and should be conducted across the three Scenarios identified in Recommendation 3.

4. Hydro should conduct one Labrador Island Link ("LIL") Shortfall Analysis run 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 the prior bullet (Recommendation 3). If no BESS resources are selected in that model run, this additional LIL Shortfall Analysis run would be unnecessary.

5. Hydro should conduct one LIL Shortfall Analysis run that limits the output of BDE to match potential hydrological resource constraints identified in Section III.H of the Bates White June Expert Report. Alternatively, Hydro should supplement the record with additional evidence that Bay d'Espoir will be able to produce at collective output levels assumed in the LIL Shortfall Analysis runs included in the Application, and that those volumes can be deliverable to the Avalon in all hours.

6. Hydro should conduct one LIL Shortfall Analysis run that assumes Holyrood Thermal Generation Station ("Holyrood TGS"), Stephenville Gas Turbine ("GT"), and Hardwoods GT are not retired, the Avalon CT is in service, and BDE Unit 8 is not in service.

    - Collectively, then, we recommend three additional LIL Shortfall Analysis runs—one for Recommendation 4, one for Recommendation 5, and one for Recommendation 6.

7. We reiterate our August 2024 recommendation for Hydro to consider employing competitive solicitation for its energy and capacity needs.

8. NPVs of the capacity expansion modeling runs should be recalculated accounting for the recalculated Management Reserves.

9. Hydro should address the load forecast discrepancy identified in Section III.B of the Bates White June Expert Report.

(3) On July 22, 2025, the Board asked Hydro to provide additional information based on the conclusions and recommendations identified in the Bates White June Expert Report.[10] Across fourteen (14) grouped questions, the Board, relying upon feedback from Bates White, requested four (4) additional model runs of the capacity expansion model, incorporating:

(a) Relaxed CT constraints and BESS exclusions; [11]

(b) Relaxed Avalon CT constraints, in size limit and in "block" constraints, reducing incremental block size from 150 MW to 50 MW;[12]

(c) BESS resource options of 4-hour and 8-hour durations assuming ELCCs of 60%;[13] and

(d) Newfoundland Power Inc.'s ("NP"; "Newfoundland Power") plan to extend the lives of its gas turbines (the Wesleyville and Greenhill GTs) in 2028 and 2029.[14]

(4) The Board also requested four (4) additional LIL Shortfall Analysis model runs, incorporating:

(a) BESS resources, if they are selected as part of the capacity expansion models above;[15]

(b) Potential impacts of hydrological constraints on the output of the BDE generation units;[16]

(c) The life extension of Holyrood TGS, Stephenville GT, Hardwoods GT, the Avalon CT in service, and BDE Unit 8 not in service;[17] and

(d) Newfoundland Power's plan to extend the lives of its gas turbines (the Wesleyville and Greenhill GTs) in 2028 and 2029.[18]

[10] Board, "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," July 22, 2025 available at: http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/correspondence/To%20Parties%20-%20Request%20to%20Hydro%20to%20Provide%20Additional%20Information%20-%202025-07-22.PDF ("Board July Letter").

[11] Board July Letter, page 2, item 2.

[12] Board July Letter, page 2, item 2.

[13] Board July Letter, page 2, item 2.

[14] Board July Letter, page 2, item 4.

[15] Board July Letter, page 2, item 3.

[16] Board July Letter, page 2, item 3.

[17] Board July Letter, page 2, item 3.

[18] Board July Letter, page 2, item 4.

(5) In additional questions, Hydro was asked to address possible inconsistencies on items such as: (1) fuel burn-off requirements;[19] (2) management reserve calculations;[20] and (3) load forecasts.[21] The Board also asked Hydro to: (4) reply to Bates White's recommendation of a competitive solicitation for energy and capacity needs;[22] (5) provide further information on the proposed life extension and capacity increase to BDE Unit 7;[23] (6) justify the depreciable lifespans used for the Avalon CT and BDE Unit 8;[24] (7) provide a *pro-forma* incremental customer rate impact analysis from 2030 through 2040;[25] (8) provide an update on the status of ongoing studies which are expected to be filed in 2025;[26] (9) consider bifurcation of the projects while the Transmission Expansion Feasibility Study remains in progress;[27] (10) address the impact on costs and in-service dates should approval be delayed to after the year's end;[28] and (11) to confirm if Hydro has a Constitutional obligation to consult and accommodate indigenous communities in the development of the new generation resources.[29]

(6) On September 11, 2025,[30] Hydro provided responses to each of the fourteen requests made by the Board and reported the results of an additional nine capacity expansion sensitivities ("September Reply").[31] These sensitivities included:

(a) Three capacity expansion sensitivities (4A, 4AC, and 4ADH) which assumed: no restrictions on CTs; smaller incremental CT blocks (47.2 MW blocks versus 141.6 MW blocks); and no restrictions BESS.[32]

[19] Board July Letter, pages 1 and 2, item 1.

[20] Board July Letter, page 3, item 6.

[21] Board July Letter, page 3, item 7.

[22] Board July Letter, pages 2 and 3, item 5.

[23] Board July Letter, page 3, item 8.

[24] Board July Letter, page 3, item 9.

[25] Board July Letter, page 3, item 10.

[26] Board July Letter, pages 3 and 4, item 11.

[27] Board July Letter, page 4, item 12.

[28] Board July Letter, page 4, item 13.

[29] Board July Letter, page 4, item 14.

[30] Hydro, "2025 Build Application – Request to Hydro to Provide Additional Information – Hydro's Reply," September 11, 2025, available at: http://www.pub.nl.ca/applications/NLH2025AvalonCombustionMarch/correspondence/From%20NLH%20-%20Reply%20to%20Boards%20Request%20for%20Addtional%20Information%20-%202025-09-11%20-%20REDACTED.pdf ("Hydro September Reply").

[31] Hydro September Reply, Transmission Letter, page 2.

[32] Hydro September Reply, Question 2a, page 1 line 15 to page 4 line 8; and page 3, Table 2.

(b) One capacity expansion plan sensitivity (4AK) which considers: the slow decarbonization case; fixed wind profile; and NP extending the lives of the Wesleyville and Greenhill GTs with costs externalized to NP.[33]

(c) One capacity expansion plan sensitivity (4AEK) which considers: the slow decarbonization case; fixed wind profile; no batteries; and NP extending the lives of the Wesleyville and Greenhill GTs with costs externalized to NP.[34]

(d) One capacity expansion plan sensitivity, identical to 4AK, but internalizing the NP Wesleyville and Greenhill GTs' life extension costs in the PLEXOS model.[35]

(e) One capacity expansion plan sensitivity, identical to 4AEK, but internalizing the NP Wesleyville and Greenhill GTs' life extension costs in the PLEXOS model.[36]

(f) One capacity expansion plan sensitivity (1AK) which considers: the reference case; fixed wind profile; and internalizing the NP Wesleyville and Greenhill GTs' life extension costs in the PLEXOS model.[37]

(g) One capacity expansion plan sensitivity (1AEK) which considers: the reference case; fixed wind profile; no batteries; and internalizing the NP Wesleyville and Greenhill GTs' life extension costs in the PLEXOS model.[38]

(7) In its September Reply, Hydro also included four additional LIL Shortfall Analyses which consider requests from the Board or provide context to the new capacity expansion plans. These include:

(a) Two LIL Shortfall Analyses where BESS was advanced to 2031 instead of the Avalon CT using (i) a single 50 MW 4-hour BESS ("Combination A"); and (ii) five 50 MW 4-hour BESS ("Combination B").[39]

(b) One LIL Shortfall Analysis assuming Holyrood TGS, Stephenville GT, Hardwoods GT, and Avalon CT are in service with BDE Unit 8 not in service.[40]

[33] Hydro September Reply, Question 4, page 1, lines 15 to 18; page 4, Table 1; and page 4 line 14 to page 6 line 5.
[34] Hydro September Reply, Question 4, page 1, line 15 to 18; page 4, Table 1; page 4 line 14 to page 7 line 10.
[35] Hydro September Reply, Question 4, page 11 line 13 to page 12 line 2.
[36] Hydro September Reply, Question 4, page 11 line 13 to page 12 line 7.
[37] Hydro September Reply, Question 4, page 11 line 13 to page 12 line 2.
[38] Hydro September Reply, Question 4, page 11 line 13 to page 12 line 7.
[39] Hydro September Reply, Question 3a, page 5 line 5 to page 11 line 1.
[40] Hydro September Reply, Question 3c, page 1, lines 9 to 14.

(c) One LIL Shortfall Analysis using the results of the 4AK and 4AEK capacity expansion plans, which were identical in the 2032 reference year.[41]

(8) Hydro did not provide expansion or LIL Shortfall Analysis models related to the potential hydrological constraints identified by Bates White.[42]

(9) This addendum report to the Bates White June Expert Report responds to the additional information received from Hydro in its September Reply. This report also relies on additional exchanges of information with Hydro subsequent to the September Reply, including email exchanges and a discussion between Hydro and Bates White on October 3, 2025.

[41] Hydro September Reply, Question 4, page 8 line 17 to page 11 line 12.

[42] Hydro September Reply, Question 3b, page 1 line 12 to page 11 line 3.

II. Executive Summary

(10) We appreciate the work completed by Hydro in its September Reply in response to the Board's July Letter. The additional information, data, analysis, and narratives have substantially enhanced the record and will assist stakeholders and the Board in completing the review of the Build Application.

(11) In our view, Hydro's September Reply fully addresses and resolves several outstanding issues raised either in the Bates White June Expert Report or the Board's July Letter. For example, Hydro satisfactorily addressed certain errors in the Build Application regarding the calculation of management reserve and its load forecast selection. (For clarity, while Hydro has addressed *errors* with the calculation of the management reserve, the project costs and respective management reserve amounts remain under review, and we plan to provide our assessment of those in a forthcoming expert report.)

(12) In addition, Hydro identified evidence of potential constraints regarding the efficacy of an uprate to BDE Unit 7 as a resource alternative that should be considered in this proceeding, though the current applicability of those constraints requires further study. Should the Board not approve BDE Unit 8 in this proceeding, the issue of BDE Unit 7's uprate could be fully assessed in the BDE Unit 7 Life Extension matter. Such an assessment should explore whether the maximum uprate of BDE Unit 7's capacity remains 5 MW.

(13) Hydro's September Reply also largely addresses other issues, though work remains to be done, either in the remainder of this proceeding or in the future. For example:

- Hydro initiated a Request for Expression of Interest ("RFEOI") process to investigate third-party supply options for the supply of up to 500 GWh/year of firm energy and 150 MW of firm capacity. We understand that other than the procurement of new wind generation from third parties, Hydro does not plan to use competitive procurement for the Avalon CT or BDE Unit 8. Given the seemingly robust response to the RFEOI, we continue to recommend that Hydro seek to introduce and invite competition from third parties in its future resource planning and development activities, and to do so earlier in the process to allow sufficient time for the work required to make third-party projects viable.

- Hydro has provided evidence that the BDE system can sustain a level of output from BDE Units 1-8 similar to that modeled in the LIL Shortfall Analysis as part of the Build Application, though the results depend on certain assumptions and conditions made by Hydro. Specifically, the results are conditioned on certain assumptions about (a) reservoir storage levels, (b) average hydrological inflows, and (c) significant spill activity that could be less favorable than assumed, which could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.

Thus, while Hydro has enhanced the evidentiary record on the question of hydrological sufficiency, the additional evidence is not sufficient to eliminate all concerns about hydrological sufficiency during an extended bipole outage of the LIL.

- Hydro has demonstrated that the existing transmission grid is sufficient to allow for power flows from Bay d'Espoir to the Avalon peninsula during normal operating conditions and single contingencies. Hydro has also filed an assessment of the effectiveness of a remedial action scheme during extended LIL bipole outages. our review of this recently filed evidence remains ongoing and our analysis will be provided in our next expert report in this proceeding.

- Hydro's additional model runs demonstrate that if the Avalon CT or BDE Unit 8 were delayed to commercial operation dates beyond 2031, the IIS would not suffer from a generation shortfall as long as Hydro's existing thermal assets remain operational. In fact, the reliability performance of the thermal portfolio plus the Avalon CT exceeds that of even Hydro's Minimum Investment Portfolio, as measured in Hydro's LIL Shortfall Analysis simulations. Hydro will need prudent investment planning to balance the risk of underinvesting in its existing assets that may be needed longer than expected against overinvesting in assets about to retire.

(14) For other issues, Hydro's September Reply provides useful information but does not resolve key underlying questions associated with the Build Application.

- First, Hydro's additional capacity expansion modeling demonstrates that Bay d'Espoir Unit 8 and the Avalon CT are similar in annual revenue requirement. Hydro acknowledged that the PLEXOS model would choose the Avalon CT as the lower cost resource when the assumption of forced fuel burn-off is removed, except that based on the projected system capacity need, the PLEXOS model identifies value from adding BDE Unit 8 first because it is modeled with 12.8 MW greater firm capacity than the Avalon CT. The additional 12.8 MW of firm capacity allows PLEXOS to defer the addition of the second resource (the Avalon CT) by one year. It is this modeled delay that creates a relative cost savings, of approximately 0.4% on a net present value basis, relative to adding the Avalon CT first. The key point is that the selection of BDE Unit 8 before the Avalon CT in this scenario is *entirely* a consequence of the 12.8 MW greater modeled firm capacity of BDE 8.

- Second, given the marginal capacity basis for initial selection of BDE Unit 8 over the Avalon CT, other factors addressed herein have significant relevance to the asserted primacy of BDE Unit 8 in Hydro's resource plan:

- After Hydro filed the Build Application, Newfoundland Power put forth plans to extend the lives of two gas turbines (totaling 48 MW of firm capacity) that Hydro had modeled as retired for the planning period. Hydro's updated modeling demonstrates that this added firm capacity reduces and/or delays the need for additional firm capacity on the IIS.

- Hydro's additional modeling demonstrates that when the full requested authorized budgets for the BDE Unit 8 and Avalon CT projects are modeled, BESS resources become economic. The additional LIL Shortfall Analysis modeling also shows that BESS resources provide meaningful reliability improvements during an extended outage of the LIL bipole, albeit at a lower contribution than the Avalon CT.

(15) Our findings in this report will inform our Phase 2 work and final recommendations on Hydro's proposed investments in its Build Application.

III. Modeling demonstrates that Bay d'Espoir Unit 8, Avalon CT are similar in cost

(16) Question 1 in the Board's July Letter addressed a seeming inconsistency identified in the Bates White June Expert Report with respect to Hydro's reported results for Scenario 4AEFC, which removed the assumed fuel burn-off requirement for the Avalon CT and the substantial associated costs.[43] Specifically, we noted that the NPV cost of the Avalon CT is lower than that of BDE Unit 8 if the fuel burn-off requirement for the Avalon CT is excluded – i.e., if it is not assumed for planning purposes that fuel for the Avalon CT will need to be burned off uneconomically on an annual basis.[44] Yet Hydro's reported results for Scenario 4AEFC, which excludes the fuel burn-off, still show BDE Unit 8 selected for a 2031 in-service data, with the Avalon CT selected later, for 2035.[45]

(17) In its response to this query, Hydro acknowledged that the PLEXOS model would in fact choose the Avalon CT as the lower cost resource under these circumstances, except for the fact that BDE Unit 8 as modeled has greater firm capacity than the Avalon CT, by 12.8 MW.[46] Hydro further states that "if the Avalon CT were to be built first in 2031… then BDE Unit 8 would be required in 2034 to meet capacity planning criteria, rather than 2035."[47] Hydro says that this case, with the Avalon CT built first, and the second resource – BDE Unit 8 – entering service in 2034 rather than 2035, would result in a total NPV $13 million greater than the least-cost option: BDE Unit 8 in 2031 and the Avalon CT in 2035.[48]

(18) For additional context, we note that the $13 million in higher NPV cost represents approximately 0.4% of the applicable NPV total for Scenario 4AEFC (BDE Unit 8 in 2031, Avalon CT in 2035) of about $3.0 billion.[49] The key point is that the selection of BDE Unit 8 before the Avalon CT in this scenario is *entirely* a consequence of 12.8 MW greater modeled firm capacity, and the cost impact of this capacity difference results from the PLEXOS model advancing the second resource by a year.

(19) As summarized below, there are important issues to resolve regarding the respective reliability contributions of BDE Unit 8 and the Avalon CT. However, even taking the scenario runs discussed here as given, a cost difference of 0.4% NPV looking out 15 years into the future is a weak basis for making a definitive, categorical resource planning selection. In its responses to the Board questions, Hydro repeatedly states (with emphasis) that BDE Unit 8 is always selected first in order with respect

[43] Bates White June Expert Report, Section III.E.iii, pages 48 to 51; Board July Letter, pages 1 to 2, item 1.

[44] Bates White June Expert Report, pages 50 to 51, paragraph 103.

[45] Build Application, Schedule 3, page 29, Section 5.2.2.1.2; and page 28, Section 5.2.2.1.1.

[46] Hydro September Reply, Question 1, page 1, lines 19 to 26.

[47] Hydro September Reply, Question 1, page 2, lines 1 to 3.

[48] Hydro September Reply, Question 1, page 2, lines 3 to 6.

[49] Hydro September Reply, Question 2a), page 11, Table 7.

to the Avalon CT, including when: (1) the fuel burn off assumptions are removed;[50] (2) BESS are permitted;[51] (3) CTs are unrestricted and cheaper incremental CT alternatives are added;[52] (4) P85 capital costs are utilized for BDE Unit 8 and the Avalon CT; [53] (5) Newfoundland Power GTs are assumed to stay in service;[54] (6) Newfoundland Power GTs are included as an expansion option;[55] and (7) in *all* Scenario 4 runs presented in the Build Application.[56] Transmission losses, which would be expected to be higher for BDE Unit 8 due to its location, are ignored here. If considered, transmission losses would likely further reduce any advantage of BDE Unit 8 over the Avalon CT. As discussed further in this report, to date we have not identified sufficient basis to match Hydro's confidence in this conclusion.

(20) With respect to the 12.8 MW firm capacity difference driving the selection of BDE Unit 8 first relative to the Avalon CT, it is almost certain that PLEXOS would reach the same result for an even smaller firm capacity difference. The primary objective for the PLEXOS capacity expansion optimization is to provide sufficient firm capacity each year to maintain system reliability at the target 2.8 loss-of-load-hours ("LOLH").[57] Hydro's model results indicate that PLEXOS sees a resource deficiency in 2034 if the Avalon CT is added in 2031, but not if BDE Unit 8 is added in 2031, because BDE Unit 8 is modeled with 12.8 MW greater firm capacity. By definition, the shortfall in 2031 must be equal to or less than 12.8 MW (as adding 12.8 MW covers the shortfall), and since the shortfall would only equal 12.8 MW by coincidence, the true shortfall seen by PLEXOS in 2031 is likely smaller, again highlighting the marginal selection basis in the given scenario.

(21) We expect that Phase 2 will provide more clarity regarding whether and to what extent the Avalon CT would require fuel to be burned off uneconomically on an annual basis. We noted in the Bates White June Expert Report that Hydro's modeling overstated the fuel-burnoff cost by at least 16%, because the annual cost was effectively assumed to continue in perpetuity. This leads to 16% of associated NPV costs to be accounted for in years beyond the assumed 35-year asset life for the Avalon CT.[58]

(22) Given the marginal capacity basis for initial selection of BDE Unit 8 over the Avalon CT, other factors addressed herein have significant relevance to the asserted primacy of BDE Unit 8 in Hydro's resource plan. Among these are:

[50] Hydro September Reply, Question 1, page 1, lines 19 to 26.
[51] Hydro September Reply, Question 2a), page 7, Table 5.
[52] Hydro September Reply, Question 2a), page 11, line 13 to page 12, line 8.
[53] Hydro September Reply, Question 2a), page 9, Table 6.
[54] Hydro September Reply, Question 2a), page 5, Table 2; page 6, Table 3.
[55] Hydro September Reply, Question 2a), page 12, Table 6; page 13, Table 7.
[56] Build Application, Schedule 3, pages 26 to 34, Section 5.2.2.
[57] Build Application, Schedule 3, page 15, Table 2.
[58] Bates White June Expert Report, page 50, paragraph 102; page 50, Figure 6.

- Potential contributions of battery storage as a resource option (Section IV)
- Hydrological sufficiency to support the assumed modeled 154.4 MW firm capacity of BDE Unit 8 (Section V);
- The sufficiency of transmission transfer capability to deliver the full incremental firm capacity of BDE Unit 8 to the Avalon peninsula (Section VI); and
- Impact on capacity need and timing from announced life extension of Newfoundland Power's CTs (Section VIII).

(23) As noted in the Bates White June Expert Report,[59] a separate issue affecting the differential values of modeled costs for BDE Unit 8 and the Avalon CT is that, although the capital cost of the Avalon CT is lower than that of BDE Unit 8 per MW of firm capacity, the modeled annualized cost of BDE Unit 8 is lower than the Avalon CT. This is because the model assumed that the BDE Unit 8 cost is amortized over a significantly longer depreciable life – 60 years for BDE Unit 8 compared to 35 years for the Avalon CT.[60]

(24) Question 9 of the Board's July Letter asked for information regarding the rationale for selecting the depreciable lives of the respective plants in the Application, which correspond to those noted above. In addition, the Board requested discussion of "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."[61]

(25) Hydro noted in its response that the depreciable lives reflected in the Build Application were based on a prior depreciation study,[62] and that the revenue requirement estimates presented in the Build Application, which depend on the depreciation assumptions, were presented as illustrative estimates.[63] Hydro considers the depreciable lives and revenue requirement estimates presented in the Application to be reasonable given the uncertainty of eventual customer rate impacts, which depend on rate mitigation decisions for the post-2030 period.[64] However, we note that the depreciable lives applied for the respective resources are important factors in the planning analysis: they determine the annual revenue requirement values applied in the PLEXOS capacity expansion model, and consequently can affect the identified least-cost resource additions and ordering. Given the potential significance of the

[59] Bates White June Expert Report, pages 41 and 42, paragraph 84.
[60] Build Application, Schedule 1, Appendix D, page D-1, lines 4 to 6.
[61] Board July Letter, page 3, item 9.
[62] Hydro September Reply, Question 9, page 1, lines 8 to 12.
[63] Hydro September Reply, Question 9, page 2, lines 5 to 7.
[64] Hydro September Reply, Question 9, page 2, lines 3 to 9.

depreciation assumptions, it would be preferable to have an updated, and ideally independent, assessment of depreciable resource lives as applicable to resource selection.

(26) Hydro applied an assumed depreciable life of 60 years for BDE Unit 8 in its planning analyses,[65] and reports that its most recent depreciation study, filed as part of its 2017 General Rate Application, has an estimated depreciable life of approximately 72 years for hydraulic generation.[66] We note that Hydro has a separate application before the Board to refurbish BDE Unit 7, after roughly 50 years of operation. This may be a more appropriate depreciable life assumption for the major mechanical and electrical components that would constitute the working equipment of BDE Unit 8. The 72-year depreciable life for hydroelectric resources from the most recent depreciation study is an average value that presumably includes long-lived elements such as dam structures that may have a 100+ year expected life. One issue we hope to clarify in Phase 2 is how future major investment activities such as refurbishment are planned and reflected in NPV cost calculations.

[65] Hydro September Reply, Question 9, page 1, lines 8 to 12.

[66] Hydro September Reply, Question 9, page 1, lines 20 to 21.

IV. Battery Energy Storage Systems as viable resource options

(27) In the Build Application, Hydro excluded consideration of BESS as resource options in its capacity expansion modeling.[67] Hydro stated:

> Based on analysis performed by Hydro as part of the *RRA Study Review*, battery energy storage systems ('BESS') are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility questions 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 Expansion Plan, (i.e., the recommended expansion plan). Hydro is committed to further study of battery [effective load carrying capability ("ELCC")] to inform the 2026 Resource Adequacy Plan.[68]

(28) In the Bates White June Expert Report, we were critical of Hydro's decision to preclude BESS resources from consideration. We noted that BESS resources were selected in several cases of Hydro's 2024 capacity expansion model runs, particularly when BESS ELCCs were reasonably assumed to be 60% or higher.[69] We therefore recommended that Hydro conduct three additional capacity expansion model runs[70] that include BESS resources of four-hour and eight-hour duration, assuming ELCCs of 60%, and using updated capital cost estimates for BESS resources.[71] We also recommended a single LIL Shortfall Analysis run using any BESS resources selected in the expansion plans identified in the additional capacity expansion model run associated with Scenario 4AEF.[72]

(29) In its September Reply, Hydro provided results for the three additional capacity expansion model runs as well as two additional LIL Shortfall Analysis runs using BESS resources, as explained below.

(30) The three additional capacity expansion model runs relevant to BESS resources used scenarios 4AEF, 4AEFC, and 4AEFDH.[73] In the modeling supporting the Build Application, these scenarios precluded BESS resources from consideration.[74] In these updated model runs, Hydro relaxed three modeled constraints: the maximum on new CT capacity (increasing from 141.6 MW to unrestricted), the minimum CT capacity addition build size (reducing from 141.6 MW to 47.2 MW), and the restriction

[67] Bates White June Expert Report, page 53, paragraph 111.

[68] Build Application, Schedule 1, page 16, footnote 26.

[69] Bates White June Expert Report, page 61, paragraph 132.

[70] Using Scenarios 4AEF, 4AEFC, and 4AEFDH.

[71] Bates White June Expert Report, page 87, paragraph 188.

[72] Bates White June Expert Report, page 87, paragraph 188.

[73] We provide an outline of the assumptions used in these scenarios and all those referenced in this report in Appendix A.

[74] Build Application, Schedule 3, Section 5.2.2.1.1, page 28; Section 5.2.2.1.2, page 29; and Section 5.2.2.1.6, page 31; Hydro September Reply, Question 2a), page 3, Table 1.

on batteries (from precluded to allowing both 4- and 8-hour batteries).[75] Hydro used updated four-hour duration BESS capital costs that were 8.9% lower than what was used in the Build Application.[76] Hydro named these three new runs in a manner consistent with its naming convention used in the Build Application, identifying these runs as scenarios 4A,[77] 4AC,[78] and 4ADH.[79]

(31) The 4A and 4AC capacity expansion model runs continue to select the same resource portfolio as the restricted runs presented in the Build Application (for Scenarios 4AEF and 4AEFC, respectively).[80] That is, BDE Unit 8 (in 2031) and Avalon CT (in 2035) are added to the system, as is new wind beginning in 2030.[81] These results suggest that assuming the "Base Cost" of both projects, BDE Unit 8 and the Avalon CT are the optimal selections in the PLEXOS model. The Base Cost of each project is defined as including "prices for direct costs, such as equipment, materials, labour, etc., and indirect costs, such as access roads, engineering, and temporary camps."[82] The Base Cost of each project does not include interest during construction, escalation, contingency, or management reserve.[83]

(32) The results of 4ADH, however, show that when capital costs for BDE Unit 8 and the Avalon CT are increased to P85 levels, the results differ from those of Scenario 4AEFDH in the Build Application. Specifically, the model selects 50 MW of four-hour duration BESS for 2035, and additional 50 MW increments of BESS in 2036, 2038, 2039, and 2040, bringing the collective total BESS selected by the model to 250 MW.[84] The model continues to pick BDE Unit8 in 2031, but no longer selects any CT capacity. The net present value of the incremental cost of the 4ADH portfolio ($3.2 billion) is also 3% lower than that of 4AEFDH ($3.3 billion).[85]

(33) These results show the sensitivity of the optimal portfolio makeup to the underlying cost estimates for BDE Unit 8 and the Avalon CT. At the Base Costs, the projects remain optimal selections in PLEXOS. However, at P85 costs, which is the full "Authorized Budget" Hydro seeks in its Build

[75] Hydro September Reply, Question 2a), page 3, lines 3 to 5 and Table 2.

[76] Hydro September Reply, Question 2a), page 5, Table 3.

[77] Hydro describes this sensitivity as using a fixed wind profile to meet firm energy criteria, and modeling all other resource options, with no restrictions. Hydro September Reply, Question 2a), page 3, Table 2.

[78] Hydro describes this sensitivity as using the same parameters as Scenario 4A, but also removing the forced CT fuel burn-off constraint. Hydro September Reply, Question 2a), page 3, Table 2.

[79] Hydro describes this sensitivity as using the same parameters as Scenario 4A, but also using higher (P85) capital cost estimates for BDE Unit 8 and the Avalon CT. Hydro September Reply, Question 2a), page 3, Table 2.

[80] Hydro September Reply, Question 2a), page 7, lines 6 to 15; and page 8, lines 14 to 26.

[81] Hydro September Reply, Question 2a), page 7, Table 5; page 8, lines 14 to 26.

[82] Build Application, Schedule 1, page 30, lines 11 to 12.

[83] Build Application, Schedule 1, page 21, lines 1 to 2.

[84] Hydro September Reply, Question 2a), page 9), Table 6.

[85] Hydro September Reply, Question 2a), page 11, Table 7.

Application, and which includes all cost components, including the planned contingency and management reserve,[86] BESS projects become economic, displacing the Avalon CT.

(34) As additional sensitivity tests, Hydro then conducted two LIL Shortfall Analysis runs which assessed a six-week LIL bipole outage in winter 2032. The first took the results from Scenario 4ADH, which builds BDE Unit 8 in 2031 and 50 MW of BESS by 2035, and advances those 50 MW of BESS to 2031.[87] The second advanced all 250 MW of BESS projects (in 50 MW increments) selected by PLEXOS through 2040 to be commissioned in 2031.[88] Hydro refers to these runs as "Combination A" and "Combination B," respectively.

(35) Given our discussion in Section III above, PLEXOS's selection of BDE Unit 8 ahead of the Avalon CT appears to be driven by the small difference in the projects' respective firm capacity, which amounts to just 12.8 MW.[89] That is, if both projects are modeled at the same firm capacity, and the assumed cost of uneconomic fuel burn-off is removed, it is the Avalon CT that is selected first, not BDE Unit 8.[90] Given the small margin between the two projects, and uncertainties regarding the consistent incremental contribution from the modeled 12.8 MW of firm capacity excess – which we discuss more fully in Sections V, VI, VII, and VIII, below – it is reasonable in our view to interpret the results of Scenario 4ADH as selecting BESS before either the Avalon CT or BDE Unit 8.

(36) The results of the LIL Shortfall Analysis runs assuming an "Average Case"[91] are shown in Table 1 below. The top row shows the results for Scenario 4AEF from the Build Application, while the bottom row shows the results for the same portfolio, except advancing the build of the Avalon CT from 2035 to 2031.[92] These two cases are the primary cases in the Build Application. The second row shows results for the 50 MW BESS build in 2032, while the third row shows results for the 250 MW BESS build in 2031.[93]

[86] Build Application, Schedule 1, page 21, lines 1 to 2.

[87] Hydro September Reply, Question 3a), page 5 lines 12 to 13.

[88] Hydro September Reply, Question 3a), page 6 lines 1 to 2.

[89] BDE Unit 8 is modeled at 154.4 MW of firm capacity; the Avalon CT is modeled at 141.6 MW of firm capacity. *See*: Build Application, Schedule 3, page 28, Table 5.

[90] Hydro September Reply, Question 1, page 1, lines 22 to 25.

[91] The Average Case, or 50th percentile case, "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." Build Application, Schedule 3, page 37 lines 19 to 21.

[92] Hydro September Reply, Question 3a), page 5, Table 2.

[93] Hydro September Reply, Question 3a), page 8, Table 4; and page 11, Table 4.

Table 1: Comparison of LIL Shortfall Analysis Results of BESS, non-BESS Portfolios (Average Case) [94]

Portfolio Scenario	Capacity Resources Built	Hours of Shortfall	Total Energy Shortfall (GWh)	Peak Shortfall (MW)	% of Time Shortfall Exceeds 100 MW
4AEF, 4A, 4AC, 4ADH	BDE Unit 8 (2031) Avalon CT (2035)	142	10	256	4.0%
BESS Combination A	BDE Unit 8 (2031) 50 MW BESS (2031)	105	6.5	212	2.5%
BESS Combination B	BDE Unit 8 (2031) 250 MW BESS (2031)	32	1.8	173	0.7%
4AEF (ADV)	BDE Unit 8 (2031) Avalon CT (2031)	24	1	124	0.1%

(37) The results confirm that the Avalon CT outperforms BESS resources in the LIL Shortfall Analysis. The addition of 250 MW of BESS resources in 2031 (Combination B) cannot match the addition of the 141.6 MW Avalon CT in hours of shortfall, total energy shortfall, peak shortfall, or the percentage of time in which the generation shortfall exceeds 100 MW. The outperformance of the Avalon CT over the BESS resources becomes greater in the "Severe Case"[95] runs.[96]

(38) That said, Table 1 above shows that BESS resources can make a substantial contribution to IIS reliability during an extended LIL bipole outage. As shown in Table 2, adding just 50 MW of BESS to the 4AEF portfolio (which includes an addition of just BDE Unit 8 by 2031) results in reductions of shortfall hours by 26%, energy shortfalls by 35%, and peak shortfalls by 17%. Adding 250 MW of BESS to the portfolio reduces shortfall hours by 78%, energy shortfalls by 82%, and peak shortfalls by 32%. These substantial reliability contributions of BESS suggest that Hydro should not continue to preclude BESS resources from being evaluated in its resource planning and capital budget modeling work.

Table 2: Impact of Adding BESS Resources to Scenario 4AEF Portfolio (Average Case) [97]

BESS Additions in 2031	Hours of Shortfall Reduction (%)	Total Energy Shortfall Reduction (%)	Peak Shortfall Reduction (%)	% of Time Shortfall Exceeds 100 MW Reduction (%)
50 MW	26.1%	35.0%	17.2%	37.5%
250 MW	77.5%	82.0%	32.4%	82.5%

[94] Hydro September Reply, Question 3a), page 5, Table 2; page 8, Table 4; and page 11, Table 4.

[95] The Severe Case, or 90th percentile case, "[r]epresents 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." Build Application, Schedule 3, page 38 lines 1 to 3.

[96] Hydro September Reply, Question 3a), page 5, Table 3; page 8, Table 4; and page 11, Table 4.

[97] Hydro September Reply, Question 3a), page 5, Table 2; page 8, Table 4; and page 11, Table 4.

(39) The LIL Shortfall Analysis results do not necessarily allow for comparison between the BESS resources and BDE Unit 8 in a LIL Shortfall Analysis, as BDE Unit 8 is built in 2031 in all scenarios. Still, we would expect BDE Unit 8 to perform similarly to the Avalon CT in a LIL Shortfall Analysis if there is sufficient hydrology for the BDE plant. That is the topic of our next section.

(40) To conclude, the three additional capacity expansion model runs and two associated LIL Shortfall Analysis runs provide critical additional information in assessing the Build Application. The runs demonstrate that at costs equal to the full requested authorized budgets for the BDE Unit 8 and Avalon CT projects, BESS resources become economic. And while those BESS resources do not provide the same level of reliability contributions as the Avalon CT during an extended outage of the LIL bipole, the BESS resources do provide meaningful reliability improvements. We therefore take no issue with Hydro not including BESS resources in its Minimum Investment Portfolio but reiterate that BESS resources should be included as viable resource options in all of Hydro's resource planning efforts going forward.

V. Hydro has enhanced the evidentiary record by demonstrating hydrological sufficiency of BDE 1-8 during an extended LIL bipole outage under certain circumstances

(41) A cornerstone of Hydro's Build Application was the LIL Shortfall Analysis, which modeled a six-week forced outage of the LIL during the "coldest period of the year (i.e., January and February)."[98] Hydro had previously noted that the possibility of an extended bipole outage on the LIL (i.e., six weeks), which was originally thought in 2018 to have a "very low probability," is likely to have a probability that is "much greater than originally thought."[99] The threat of an extended outage is present, according to Hydro, "[e]ven if the LIL consistently has a LIL bipole [equivalent forced outage rate] towards the bottom end of the analyzed range (1%)" because there still exists the risk of line icing or "other failure modes."[100] Hydro made it clear that an extended outage on the LIL would be a "high consequence event impacting the Island Interconnected System."[101]

(42) In the Bates White June Expert Report, we agreed that the LIL Shortfall Analysis was a "sensible and necessary assessment, primarily due to the unique resource adequacy profile of Hydro and its reliance on the LIL."[102] We explained that since "[t]raditional probabilistic metrics of resource adequacy, including Hydro's selected probabilistic criteria of 2.8 [loss of load hours], may not capture the full risk of the loss of an asset like the LIL for an extended period…an additional, probabilistic assessment of an extended LIL outage is merited."[103] However, we also explained that the LIL Shortfall Analysis in the Build Application "may overstate the reliability contribution of BDE 8 during an extended bipole outage of the LIL."[104] We noted in particular that "due to potential hydrological constraints, and absent additional supporting information from Hydro, it is not clear from the data that the collective plant can realistically produce the level of output assumed in the analysis."[105] We recommended, therefore, that either Hydro "conduct one LIL Shortfall Analysis run that limits the output of Bay d'Espoir to match potential hydrological resource constraints," or, alternatively, "Hydro should supplement the record with additional evidence that Bay d'Espoir will be able to produce at collective output levels assumed in the LIL Shortfall Analysis runs included in the Application."[106]

[98] Build Application, Schedule 3, page 37, lines 10 to 11.

[99] Hydro, "Reliability and Resource Adequacy Study 2022 Update," October 3, 2022, ("2022 RRA Update"), Volume III, page 27 line 23 to page 28, line 3.

[100] 2024 RAP, Appendix C, page 100, lines 9 to 11.

[101] 2024 RAP, Appendix B, page 4, footnote 11.

[102] Bates White June Expert Report, page 29, paragraph 53.

[103] Bates White June Expert Report, page 29, paragraph 53.

[104] Bates White June Expert Report, page 67, paragraph 145.

[105] Bates White June Expert Report, page 81, paragraph 177.

[106] Bates White June Expert Report, page 86, paragraph 187.

(43) In its July Letter, the Board requested that Hydro address our recommendation on this point, either through an additional LIL Shortfall Analysis run or through providing additional evidentiary support that Bay d'Espoir will be able to produce at the collective output levels assumed in the LIL Shortfall Analysis runs included in the Build Application.[107]

(44) In its September Reply, Hydro opted to provide additional evidence and no additional LIL Shortfall Analysis runs, stating: "[Hydro] confirms that the [Bay d'Espoir] system has adequate hydrology supply with the addition of BDE Unit 8."[108] Hydro noted the 2024 Hatch Report,[109] provided in the 2024 Resource Adequacy Plan, which, according to Hydro, "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."[110] Hydro noted that "[r]esults from all simulations, including the outage case simulations, indicate that the BDE system has adequate hydrology supply with the addition of BDE Unit 8."[111] Hydro noted that in those simulations, the "low supply level of the reservoirs in the BDE system, including Long Pond, was not violated," and moreover, "in no scenario was the bypass of the North Salmon Dam required, which is an additional option to supply Long Pond and thus further support the BDE Hydroelectric Generating Station, if necessary."[112] Importantly, and as we explain below, the 2024 Hatch Report modeled a scenario of higher reliance on thermal generation (and less reliance on output from BDE), which limits the usefulness of the 2024 Hatch Report in assessing hydrological sufficiency during an extended LIL bipole outage.

(45) Hydro's September Reply failed to accomplish the task at hand, which was to either demonstrate that the hydrological system that feeds the BDE plant is sufficient to sustain the modeled operation of BDE in the LIL Shortfall Analysis, or to conduct an additional LIL Shortfall Analysis run that modeled hydrological constraints. Following our review of Hydro's September Reply, we held multiple information exchanges with Hydro, including an October 3, 2025 conference call and several email exchanges.

(46) Hydro referenced the July 2024 Hatch Report as evidence of hydrological sufficiency. Hatch appropriately uses a model (Vista) that captures hydrological constraints, while the model used by Hydro in the LIL Shortfall Analysis (PLEXOS) does not. Thus, the Vista model can provide the evidence needed to demonstrate hydrological sufficiency of the BDE system to support the PLEXOS model's generation output from BDE during a six-week LIL outage. While the Hatch Report does conclude that "the system has adequate reservoir storage to make up for the loss of imports by

[107] Board July Letter, page 2, item 3b).

[108] Hydro September Reply, Question 3b), page 1, lines 12 to 15.

[109] Hatch, Ltd., "Impact of Prolonged Loss of LIL on Island Reservoir Levels," July 2, 2024, provided in the 2024 RAP, Appendix C, Attachment 5 ("July 2024 Hatch Report").

[110] Hydro September Reply, Question 3b), page 6, lines 10 to 11.

[111] Hydro September Reply, Question 3b), page 6, lines 21 to 22.

[112] Hydro September Reply, Question 3b), page 6, lines 24 to 26.

increasing hydro and thermal generation to maintain reservoir storage through the winter period,"[113] it does not demonstrate the hydrological sufficiency to support Bay d'Espoir's collective hourly output contained in Hydro's LIL Shortfall Analysis modeling results.

(47) As shown in our Phase 1 report, the LIL Shortfall Analysis results in an average of 691.4 GWh of output from Bay d'Espoir over a six-week period across 120 model runs, with the plant collectively operating at an average capacity factor of 89.3%.[114] To demonstrate for purposes of the Build Application that there are no hydrological constraints preventing Bay d'Espoir from collectively producing this level of output, Hydro would need to provide a Vista model run that results in the same (or similar) output from BDE without violating hydrological minimums at Long Pond and associated reservoirs that feed BDE.

(48) Instead, however, the Vista modeling done by Hatch in its July 2024 Report results in substantially less output coming from BDE than what was modeled in PLEXOS. Specifically, in the January 2032 scenario put forth in the July 2024 Hatch Report, just 129 GWh of additional energy is produced by *all* hydro generation on the system, which includes generation from the 84 MW Upper Salmon and 40 MW Granite Canal hydroelectric generating plants in addition to Bay d'Espoir.[115] Hatch notes: "In January the system is early in the winter drawdown and the modeling simulation indicate that a stronger thermal response is prudent, to maintain sufficient reservoir storage for later in the season."[116] Thus, in the July 2024 Hatch Report, the system relies heavily on thermal generation for incremental output, not hydroelectric generation. Hatch results show about 149 GWh of additional generation comes from thermal resources.[117] Over 120 model runs in the LIL Shortfall Analysis, only about 30 GWh on average of additional energy comes from the Avalon CT.[118]

(49) In short, therefore, we did not agree that the July 2024 Hatch Report demonstrates that Bay d'Espoir has sufficient hydrological resources to support the modeled output of the plant in the LIL Shortfall Analysis included by Hydro in its Build Application. PLEXOS does not have the ability to model hydrological constraints, while Vista does. Here, however, the Vista results don't match PLEXOS's results and assume far less output from Bay d'Espoir than that modeled by PLEXOS. Thus, while the July 2024 Hatch Report provides useful information about the ability to rely upon a combination of thermal and hydro generation during a six-week LIL bipole outage, it does not seem to demonstrate that there is sufficient hydrology to operate Bay d'Espoir in a manner that is assumed in the results of the LIL Shortfall Analysis.

[113] July 2024 Hatch Report, page 2.

[114] Bates White June Expert Report, page 67, paragraph 146.

[115] July 2024 Hatch Report, page 2, Table 1-1.

[116] July 2024 Hatch Report, page 2.

[117] July 2024 Hatch Report, Table 1-1.

[118] BW-NLH-004 ACT Generation.xls.

(50) We provided our assessment of the continued evidentiary deficiency to Hydro through emails and an additional conference call held October 3, 2025. Our exchanges considered multiple options for addressing this evidentiary gap. Ultimately, Hydro informed Bates White that it was pursuing an additional model run using Vista, referred to here as the "October 2025 Vista Study," and generally in footnotes as "Information provided to Bates White."[119]

(51) On October 19, 2025, Hydro provided Bates White the results of the October 2025 Vista Study.[120] The run modeled a six-week winter outage of the LIL (January 1 to February 11) and modeled seven total months (January 1 through July 31) to assess reservoir storage levels.[121] The model assumed Long Pond was at 92% of its maximum operating level at the start of the simulation,[122] and the Meelpaeg and Victoria reservoirs would be at 75% each.[123] For inflows to Long Pond, Hydro used actual data from January through March of 2019, which "corresponds to a 50th percentile inflow volume."[124] For the overall island system, Hydro used a series with a 50th percentile total inflow volume for the Island system from January 1 to July 31 for the period 1950-2024.[125] Hydro modeled a minimum storage buffer of 50 MCM for Long Pond.[126] In the October 2025 Vista Study, the model was allowed to release additional flow to Long Pond via the North Salmon Spillway to bypass the Upper Salmon power plant.[127] Hydro also modeled a minimum end water level for the three relevant reservoirs (Long Pond, Meelpaeg, and Victoria) that were equal to a 20-year historical average value for the last day of the simulation (July 31).[128]

(52) The results of the October 2025 Vista Study showed that the generation output from BDE collectively averaged 674 MW per hour throughout January, reaching as high as 700 MW in early February.[129] Output from BDE during peaking hours in the simulation during the six-week LIL bipole outage averaged 725 MW.[130] In total, BDE collectively provided 684 GWh of output during the six-week LIL bipole outage period.[131] Hydro explained that the model used in the October 2025 Vista Study assumed 40 MW of regulating reserve from the BDE plant as well, limiting its overall output.[132]

[119] October 10, 2025 email from Hydro to Bates White.
[120] Information provided to Bates White.
[121] Information provided to Bates White.
[122] Information provided to Bates White.
[123] Information provided to Bates White.
[124] Information provided to Bates White.
[125] Information provided to Bates White.
[126] Information provided to Bates White.
[127] Information provided to Bates White.
[128] Information provided to Bates White.
[129] Information provided to Bates White.
[130] Information provided to Bates White.
[131] Information provided to Bates White.
[132] Information provided to Bates White.

(53) During the modeled period, reservoir levels remain above modeled minimums and ultimately recover following the six-week LIL bipole outage event. Reservoir levels at Long Pond and Meelpaeg sharply decline during the modeled period, reaching as low as 11% and 18% of maximum operating levels by the end of March, respectively.[133] Victoria Reservoir reaches 65% of its maximum operating level at that time.[134] By the end of the simulation on July 31, reservoir levels increase to at least 71% across the three reservoirs.[135] This is shown in Table 3 below.

Table 3: Changes in Reservoir Storage, as a percentage of Maximum Operating Levels

	Victoria Reservoir	Meelpaeg Reservoir	Long Pond Reservoir
Start Level (% Maximum Operating Level ("MOL"))	75%	75%	92%
End of Outage Level (% MOL)	78%	32%	72%
End of Winter (March 31) Level (% MOL)	65%	18%	11%
End of Simulation (July 31) Level (% MOL)	81%	73%	71%

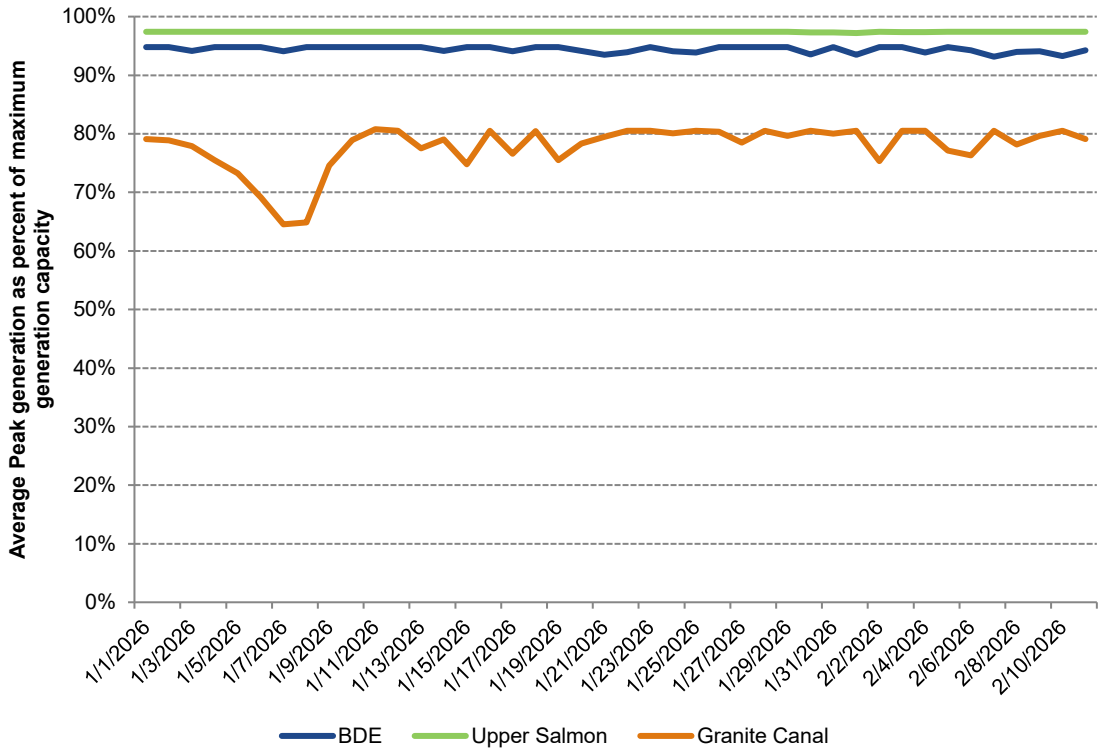
(54) In our view, the October 2025 Vista Study produced by Hydro to Bates White greatly enhances the evidentiary record regarding the hydrological capability of the BDE system to sustain the level of output at Bay d'Espoir modeled by PLEXOS in the LIL Shortfall Analysis filed as part of the Build Application. Moreover, the modeling shows that under the conditions assumed by the model in the October 2025 Vista Study (addressed further below), there is sufficient hydrology to support the collective output from BDE – including BDE Unit 8 – that was modeled in the LIL Shortfall Analysis. Reservoir levels are sufficiently sustained, and ultimately recover to at least 71% of their respective maximum operating limits by the end of July. We also verified that the generation output from all generation on the BDE system – which includes BDE Units 1-8, Upper Salmon, and Granite Canal – collectively operate near full capacity during the six-week LIL bipole outage. This is an important confirmation to ensure that higher incremental output at BDE is not coming at the expense of displacing potential output at Upper Salmon and/or Granite Canal. Figure 1 below shows each plant's average daily output during peak hours as a percentage of its maximum capacity.

[133] Information provided to Bates White.

[134] Information provided to Bates White.

[135] Information provided to Bates White.

Figure 1: Average peak generation as percentage of maximum generation capacity during the LIL outage period



(55) These results do appear to be conditioned on certain assumptions made by Hydro and inputted into the modeling presented in the October 2025 Vista Study. First, the modeling assumed that Long Pond would enter the six-week LIL bipole outage with hydrological capacity equal to 92% of its maximum operating level.[136] Hydro explained that its "normal target range for the Long Pond Reservoir in preparation for winter is 90-92% of maximum operating level," though "operational decisions are at all times a balance of cost and reliability."[137] Hydro further notes that due to the planned retirement of Holyrood TGS and the addition of an eighth unit at BDE, Hydro will pursue the 90-92% target storage range for Long Pond "more aggressively than in the past."[138] Lower storage levels than assumed at Long Pond (and at Meelpaeg and Victoria) could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.

(56) Second, the results are conditioned on assumed average inflows to the system. There is a 50% chance that inflows will be less than modeled by Hydro, and it is not clear at what point inflows become

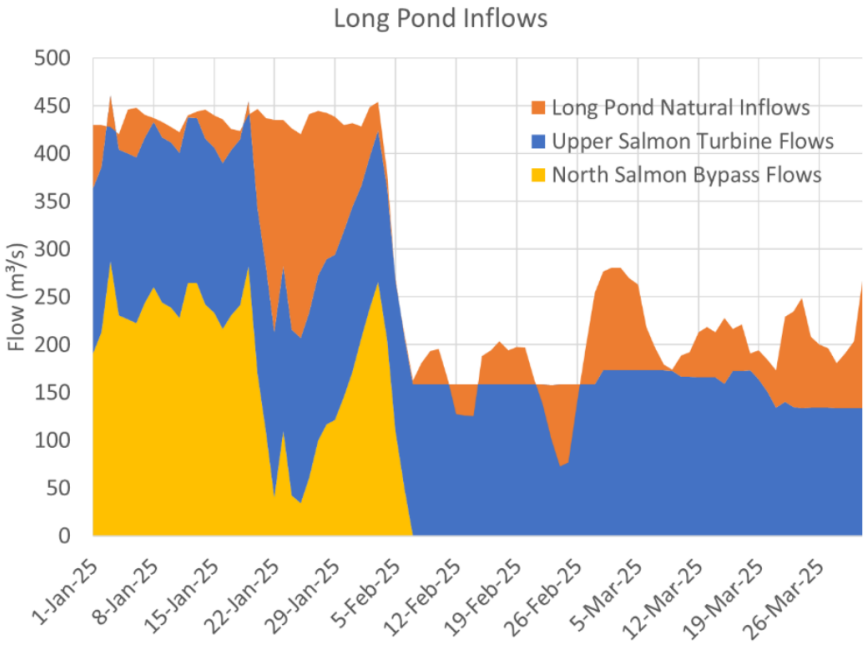
[136] Information provided to Bates White.

[137] Information provided to Bates White.

[138] Information provided to Bates White.

insufficient to sustain the modeled level of output from BDE Units 1-8. Moreover, the modeled inflows for Long Pond during the winter were determined by selecting actual data from a prior year (2019) that "corresponded" to P50 values, but were not determined through a statistical approach that takes P50 values for each day based on historical data.[139] This approach impacts the results, as the model in the October 2025 Vista Study included large natural inflow events to Long Pond in the late January 2019 period. Figure 2 below shows the three sources of inflows to Long Pond: natural inflows (in orange), inflows from the Upper Salmon turbine (blue), and inflows from the North Salmon Bypass spillway (yellow). The late January high natural inflow event can be seen in in the figure, where natural inflows displace Upper Salmon and North Salmon Bypass inflows in the middle of the outage period.

Figure 2: Long Pond Inflows (October 2025 Vista Study, January 1 through March 31)[140]



(57) Hydro notes that the natural inflows shown in Figure 2 above come from actual data in 2019, including data from January 21, 2019, when an average daily temperature of +4.9 degrees Celsius and precipitation of 75 mm was recorded at the Long Pond intake station.[141] The selection of 2019 data to simulate Long Pond inflows is advantageous in this case. And given that the assumed Long Pond inflows correspond to a P50 confidence level compared to historical data, there is a 50% chance that actual inflows would be lower than what is assumed, potentially increasing the risk of hydrological

[139] Information provided to Bates White.
[140] Information provided to Bates White.
[141] Information provided to Bates White.

shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.

(58) Third, the October 2025 Vista Study relies on the assumption of significant spill activity. Inflows modeled to Long Pond during a LIL outage are shown below in Table 4.

Table 4: Long Pond Inflows During LIL Outage (January 1 to February 11)[142]

	North Salmon Bypass Flow	Upper Salmon Turbine Flow	Long Pond Natural Inflow	Total Long Pond Inflows
Volume (MCM)	592	614	225	1,432
Percent of total inflows	41%	43%	16%	-

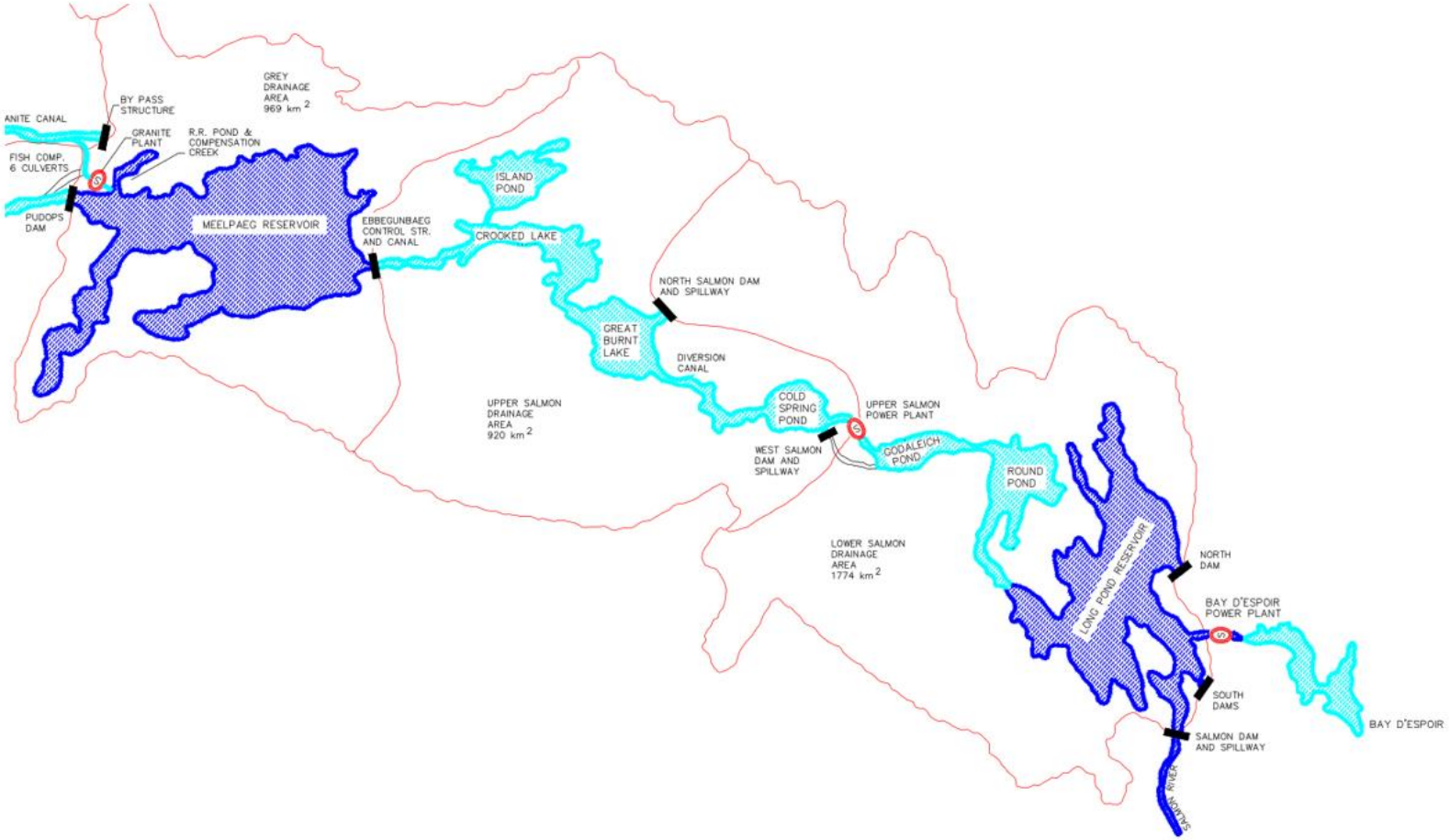
(59) Specifically, the model results in the October 2025 Vista Study show that 592 MCM of water is spilled over the North Salmon Bypass spillway to Long Pond, representing about 41% of all inflows to Long Pond during the modeling period.[143] This is a large amount of spill activity and is in fact nearly equal to the assumed inflows from the Upper Salmon generating turbine to Long Pond during this period (614 MCM, or 43% of all inflows).[144] Figure 3 below shows a portion of the BDE hydrological system, including Meelpaeg and Long Pond Reservoirs, the Upper Salmon and BDE power plants, and the North Salmon Bypass spillway.

[142] Information provided to Bates White.

[143] Information provided to Bates White.

[144] Information provided to Bates White. The remaining inflows to Long Pond (225 MCM, or 16%) are natural inflows.

Figure 3: BDE Hydrology Map (partial view)[145]



[145] 2022 RRA Update, Volume III, Attachment 7, page 5, Figure 2-2.

(60) Hydro noted in its October 2025 Vista Study that this level of spill is "within…normal operational capability,"[146] but also noted in our October 3, 2025 discussion that Hydro seeks to avoid spilling due to safety risks and the ecological impact of spilling.[147] We understand that the risks associated with spilling are significant and that Hydro issues advisories to residents, cabin owners, and travelers when Hydro is spilling water.[148] While operationally possible, there could be other safety and ecological constraints that could reduce actual spillway inflows to Long Pond below what was modeled in the October 2025 Vista Study. These lower inflows could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.

(61) We conclude, therefore, that Hydro has provided evidence that the BDE system can sustain a similar level of output from BDE Units 1-8 as was modeled in the LIL Shortfall Analysis as part of the Build Application, though the results depend on certain assumptions and conditions made by Hydro. Specifically, the results are conditioned on certain assumptions about average storage levels, average inflows, and significant spill activity that could be less favorable than assumed, which could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event. We also acknowledge the value of the July 2024 Hatch Study, which shows that, through much higher reliance on thermal generation, there is hydrological sufficiency to sustain BDE Unit 1-8's output during a six-week bipole outage of the LIL in the winter season. In sum, while Hydro has enhanced the evidentiary record on the question of hydrological sufficiency, the additional evidence is not sufficient to preclude any concerns about hydrological sufficiency during an extended bipole outage of the LIL.

[146] Information provided to Bates White.

[147] Notes from October 3, 2025 call with Hydro.

[148] *See, for example*: Newfoundland and Labrador Hydro, "Spill Advisory-multiple locations," April 26, 2022, available at: https://nlhydro.com/spill-advisory-multiple-locations/.

VI. Hydro has demonstrated transmission grid sufficiency for BDE to Avalon flows in most conditions, with evidence of sufficiency during LIL bipole outage hours just received and under review

(62) Question 3b of the Board's July Letter requested additional LIL Shortfall Analysis runs that would address BESS resources (discussed in Section IV), potential hydrological resource constraints at Bay d'Espoir (discussed in Section V), and potential life extension of Hydro's thermal generation (discussed in Section VII). The Board also requested further evidence that the modeled Bay d'Espoir output levels can be deliverable to the Avalon in all hours.[149]

(63) In its September Reply, Hydro did not include any new LIL Shortfall Analysis runs assessing this issue. Instead, Hydro provided the results of the Newfoundland and Labrador System Operator's ("NLSO's") load flow studies, which confirm that there are no current transmission constraints limiting the deliverability of Bay d'Espoir output, including BDE Unit 8, to the Avalon under normal system conditions.[150] The load flow studies also support the conclusion that transmission does not limit delivery of power under normal operation or any contingency event, other than a bipole outage of the LIL.[151] The NLSO identifies constraints on the 230 kV lines to the Avalon during a LIL bipole outage (N-2 contingency), "but it is outside the scope of the annual assessment and is currently being investigated as part of various studies in support of the [Reliability and Resource Adequacy proceeding]."[152]

(64) We confirmed with Hydro that the "various studies" referred to by the NLSO was in fact the then-ongoing TransGrid Solutions ("TransGrid") Study referenced by Hydro in its Build Application.[153] Hydro confirmed as such and noted in its September Reply that the TransGrid Study was completed.[154] Hydro further stated that "[d]uring a LIL shortfall, required volumes will be deliverable through expanded transmission capacity."[155]

(65) On October 14, 2025, Hydro filed the TransGrid Study regarding the viability of a Remedial Action Scheme ("RAS") to address transmission limits that would exist during a LIL shortfall.[156] In response

[149] Board July Letter, page 2, item 3b).

[150] Hydro September Reply, Question 3b), page 8, line 26 to page 9, line 12.

[151] Newfoundland and Labrador Hydro System Operator, "NLSO Report – 2025 Annual Planning Assessment," May 6, 2025 ("NLSO Planning Assessment"), pages 6 to 8, available at: http://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/TP-R-092_FINAL_Rev_1_05062025.pdf.

[152] NLSO Planning Assessment, page 8.

[153] Build Application, Schedule 3, page 50, lines 22 to 24.

[154] Hydro September Reply, Question 3b), page 10, line 10 to page 11, line 1.

[155] Hydro September Reply, Question 3b), page 10, lines 10 to 11.

[156] Newfoundland and Labrador Hydro, Avalon Remedial Action Scheme Feasibility Study, October 14, 2025.

to Question 12 of the Board's July Letter, Hydro summarized key conclusions of the report that (1) the RAS is confirmed to be an effective solution in a LIL shortfall scenario and (2) that the RAS would eliminate the need for additional transmission upgrades associated with delivering power from Bay d'Espoir, inclusive of BDE Unit 8.[157]

(66) For purposes of being responsive to the Board's July Letter, Hydro has provided a thorough response, including supporting evidence from NLSO load flow analyses that demonstrate the sufficiency of the transmission system to accommodate flows from BDE to the Avalon during normal operating conditions and all N-1 contingencies. Regarding the question of transmission sufficiency during LIL bipole outage hours, that question was out of scope for the NLSO Planning Assessment but is purported to be addressed by the October 2025 TransGrid Study. We will review this study and address its findings in a forthcoming expert report.

[157] Hydro September Reply, Question 12, page 1, lines 13 to 20.

VII. Delays in retirement of Hydro's existing thermal assets would have costs, but would not harm resource adequacy, even without BDE Unit 8

(67) In its Build Application, Hydro explained that certain existing thermal generating assets would be maintained through a "Bridging Period," ending in 2030, at which point new firm capacity was needed.[158] The thermal assets include Holyrood TGS, Hardwoods Gas Turbine, and Stephenville Gas Turbine, plus Newfoundland Power's Greenhill and Wesleyville Gas Turbines.[159] Collectively, these resources total 618 MW of firm capacity, 590 of which is owned by Hydro.[160]

(68) In the Bates White June Expert Report, we explained that Hydro identified three conditions that must be met before the thermal retirements can proceed. Specifically, Hydro stated: "The units at the Holyrood TGS, Hardwoods [GT], and Stephenville GT shall remain available through the Bridging Period until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met"[161] We concluded that these three conditions have value "insofar as they aim to ensure a reliable transition as Hydro's resource portfolio turns over," but that each condition "carries risk" that can delay the thermal retirements.[162] Given the potential for the thermal asset retirement dates to be delayed beyond 2030, we recommended that Hydro conduct "one LIL Shortfall Analysis run that assumes Holyrood TGS, Stephenville GT, and Hardwoods GT are not retired, the Avalon CT is in service, and BDE 8 is not in service."[163]

(69) In its September Reply, Hydro provided the results of this LIL Shortfall Analysis run.[164] The results show that with the thermal assets in service, plus the Avalon CT (but not BDE Unit 8), there is no generation shortfall in any hour during a six-week bipole outage under the Average Case.[165] In the severe case, there are just 19 hours of shortfall, 0.4 GWh of energy shortfall, and a peak shortfall of just 120 MW (with the percentage of hours with a shortfall greater than 100 MW of less than 0.1%).[166] Hydro notes that given the age (and associated high forced outage rates) of the thermal assets, the severe case, which models higher forced outage rates of the thermal resources, is a more appropriate case to consider for this sensitivity.[167]

[158] Build Application, Schedule 1, page 16, footnote 17.
[159] Build Application, Schedule 3, page 34 lines 1 to 2; 2024 RAP, Appendix B, page 42, Table 8.
[160] Bates White June Expert Report, page 31, paragraph 59.
[161] Build Application, Schedule 3, page 13 footnote 23; Bates White June Expert Report, page 31, paragraph 61.
[162] Bates White June Expert Report, page 32, paragraph 65.
[163] Bates White June Expert Report, page 87, paragraph 188.
[164] Hydro September Reply, Question 3c).
[165] Hydro September Reply, Question 3c), page 3, Table 1.
[166] Hydro September Reply, Question 3c), page 3, Table 1.
[167] Hydro September Reply, Question 3c), page 3 lines 8 to 20.

(70) One takeaway from these results is that if BDE Unit 8 was either delayed or approved for a start date beyond 2031, the IIS would not suffer from a generation shortfall. In fact, the performance of the thermal portfolio, plus the Avalon CT, exceeds that of even Hydro's Minimum Investment Portfolio.[168]

(71) Though resource adequacy would not suffer in this scenario, there would be costs associated with maintaining the thermal assets. We previously noted that Hydro estimates an average of $138.4 million per year to maintain and operate Holyrood TGS from 2030 to 2035,[169] at which point the plant would need to be retired to comply with federal Clean Electricity Regulations.[170]

(72) Assuming Board approval of BDE Unit 8 and the Avalon CT as proposed, all this suggests Hydro will be challenged to manage the timelines of those projects while also determining capital expenditures, maintenance, and other sustaining capital associated with its thermal assets as 2030 approaches. Delays in the development schedules of either BDE Unit 8 or the Avalon CT will necessarily delay the planned retirement of the thermal assets, as would LIL forced outage rates of 1% or higher and generation reserve shortfalls. As we previously explained, Hydro will need to balance the risk of underinvesting in its existing assets that may be needed longer than expected against overinvesting in assets about to retire.[171] Prudent planning and decision making will be needed.

[168] Build Application, Schedule 3, page 48, Table 9; Hydro September Reply, Question 3c), page 3, Table 1. This is true even when the Severe Case is assumed for the thermal portfolio plus Avalon CT, and the Average Case is assumed for 4AEF(ADV).

[169] Bates White June Expert Report, page 32, paragraph 66; and page 33, Table 1.

[170] 2024 RAP, Plan Overview, page 17, lines 17 to 20.

[171] Bates White June Expert Report, page 33, paragraph 67.

VIII. Newfoundland Power's plan to extend the lives of its gas turbines provides meaningful resource adequacy contribution to the IIS

(73) In its Build Application, filed on March 21, 2025, Hydro's capacity expansion modeling assumed two gas turbines owned by Newfoundland Power – the Greenhill and Wesleyville gas turbines, located on the IIS – would be retired in 2030.[172] On June 27, 2025, Newfoundland Power submitted its 2026 Capital Budget Application, which included its 2026-2030 Capital Plan, in which Newfoundland Power stated: "[Newfoundland Power] is forecasting the refurbishment of thermal generation units at Greenhill, Wesleyville, and the start of engineering to replace the thermal generation units in Port aux Basques over the next five years."[173] Newfoundland Power forecasts the refurbishment work on Greenhill and Wesleyville gas turbines to be complete by 2029.[174]

(74) In its July Letter, the Board directed Hydro to "[p]rovide 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."[175]

(75) Hydro completed the requested analysis and provided a summary of the results in its September Reply.[176] For purposes of the analysis, Hydro assumed that the total firm capacity contribution of the two Newfoundland Power gas turbines was a combined 48 MW.[177] This is likely a conservative assumption, as Newfoundland Power also plans to refurbish the thermal generation at Port Aux Basques, which totals 8.5 MW,[178] which Hydro did not appear to include in its assumptions for these model runs. Hydro completed four directly-responsive capacity expansion model runs, plus a LIL Shortfall Analysis run (across both the average and severe cases).[179] The results of the four capacity expansion model runs are shown in the table below.

[172] Bates White June Expert Report, paragraph 59; 2024 RAP, Appendix B, page 42, Table 8.

[173] Newfoundland Power, "Newfoundland Power 2026-2030 Capital Plan," June 2025 ("Newfoundland Power 2026-2030 Capital Plan"), page 1, available at: http://www.pub.nf.ca/applications/NP2026Capital/app/From%20NP%20-%202026%20Capital%20Budget%20Application%20-%202025-06-27.PDF.

[174] Newfoundland Power 2026-2030 Capital Plan, page 19.

[175] Board July Letter, page 2, item 4.

[176] Hydro September Reply, Question 4.

[177] Hydro September Reply, Question 4, page 1, lines 5 to 6.

[178] Newfoundland Power 2026-2030 Capital Plan, footnote 37.

[179] Hydro September Reply, Question 4, page 4, Table 1; page 5, Table 2; page 6, Table 3; page 12, Table 6; page 13, Table 7.

Table 5: Capacity Expansion Model Results for Four Scenarios, including Newfoundland Power Gas Turbines[180]

Scenario	Description	Newfoundland Power CTs	BDE Unit 8	Avalon CT	BESS	Wind	NPV ($ billion)
AK	Fixed Wind, NP GTs Refurbished	48 MW (2030)	154.4 MW (2031)	Not built	30 MW (2037) 30 MW (2039) 30 MW (2040)	100 MW (2030) 200 MW (2031) 100 MW (2033) 100 MW (2038)	$2.8
AK Cost Sensitivity	Fixed Wind, NP GTs Refurbishment Cost Added	48 MW (2035)					$2.9
AEK	Fixed Wind, NP GTs Refurbished, No BESS	48 MW (2030)		94.4 MW (2037)	Model prohibits BESS		$2.9
AEK Cost Sensitivity	Fixed Wind, No BESS, NP GTs Refurbishment Cost Added	48 MW (2035)					$3.0

(76) Table 5 above provides some key insights. First, the firm capacity contribution of the Newfoundland Power gas turbines directly offsets the need for additional capacity from other resources, which both reduces the total firm capacity built by the model from other sources and delays those builds. Specifically, in all four scenarios, the model does not require additional capacity beyond the contributions of BDE Unit 8, wind additions, and the Newfoundland Power gas turbines until 2037. (In the Build Application's Scenario 4AEF, the Avalon CT is built in 2035.)[181] In all four cases, the total firm capacity build beyond the contributions of BDE Unit 8, wind additions, and the Newfoundland Power gas turbines is between 90 MW (from BESS) and 94.4 MW (from Avalon CT), as compared with 141.6 MW in Scenario 4AEF.[182] These results are not surprising, as the model appropriately recognizes the firm capacity contribution of the Newfoundland Power gas turbines as any other firm capacity resource contribution.

(77) Second, when the capacity expansion model is allowed to select BESS resources, BESS resources are selected over the Avalon CT. This can be seen in the results for Scenarios AK and AK Cost Sensitivity in the table above.

(78) Third, Hydro provides "Cost Sensitivity" runs in which the model is offered the choice to add the Newfoundland Power gas turbines at a cost of $2,500/kW, rather than having those turbines be assumed in service in 2030 as in the base runs.[183] In these sensitivity runs, the model selects the Newfoundland Power gas turbines in 2035, ahead of the BESS resources (in the AK Cost

[180] Hydro September Reply, Question 4, page 4, Table 1; page 5, Table 2; page 6, Table 3; page 12, Table 6, page 13, Table 7. The NPV data for the base runs of Scenarios AK and AEK include no incremental refurbishment cost of the Newfoundland Power gas turbines. Hydro September Reply, Question 4, page 5, lines 15 to 19; and page 11, lines 14 to 17.

[181] Build Application, Schedule 3, page 28, Table 5.

[182] Build Application, Schedule 3, page 28, Table 5.

[183] Hydro September Reply, Question 4, page 5, lines 15 to 19; and page 12, lines 10 to 11.

Sensitivity)[184] and Avalon CT (in the AEK Cost Sensitivity).[185] The model then selects incremental resources in 2037 (BESS in the AK scenario where it is allowed to be selected, the Avalon CT in the AEK scenario).[186]

(79) The LIL Shortfall Analysis results are shown next in Table 6 below. The table contains results for Scenarios 4AK and 4AEK, as well as for Scenario 4AEF (the primary capacity expansion model run underpinning the Build Application) and Scenario 4AEF (ADV), which advances the build of the Avalon CT from 2035 to 2031 to meet LIL Shortfall Analysis criteria.

Table 6: LIL Shortfall Analysis Results for Scenarios AK/AEK, 4AEF, 4AEF (ADV) (Average Case)[187]

Portfolio Scenario	Hours of Shortfall	Total Energy Shortfall (GWh)	Peak Shortfall (MW)	% of Time Shortfall Exceeds 100 MW
4AEF	142	10	256	4.0%
4AK, 4AEK	95	6	219	2.3%
4AEF (ADV)	24	1	124	0.1%

(80) The results in Table 6 show that the portfolios that include the Newfoundland Power gas turbines (plus the addition of BDE Unit 8 in 2031) outperform the portfolio that builds BDE Unit 8 in 2031 and the Avalon CT in 2035 (Scenario 4AEF). This is expected, as Scenarios 4AK and 4AEK include the 48 MW of gas turbine firm capacity added in 2030,[188] before the study year (2032),[189] while Scenario 4AEF's addition of the Avalon CT does not occur until 2035, after the study year.[190] However, the results also show that the runs with the Newfoundland Power gas turbines (plus BDE Unit 8) do not provide sufficient firm capacity to meet the LIL Shortfall Analysis criteria of avoiding load shed events that exceed 100 MW on the IIS. Specifically, hours in which load shed events were modeled at more than 100 MW was 2.3%.[191] By comparison, the portfolio that includes BDE Unit 8 and the Avalon CT in 2031 (Scenario 4AEF (ADV)) saw just 0.1% of hours in which generation shortfall exceeded 100 MW.[192]

(81) In addition to the evidence explained above, Hydro provided results from two additional capacity expansion model runs. In these two scenarios – 1AK and 1AEK – Hydro used the Reference Case load forecast, not the Slow Decarbonization Case that was used in supporting the model runs that

[184] Hydro September Reply, Question 4, page 12, Table 6.
[185] Hydro September Reply, Question 4, page 13, Table 7.
[186] Hydro September Reply, Question 4, page 12, Table 6; and page 13, Table 7.
[187] Hydro September Reply, Question 4, page 10, Table 4; and Question 3a), page 5, Table 2.
[188] Hydro September Reply, Question 4, page 3, lines 6 to 9; and page 3, footnote 7.
[189] Build Application, Schedule 3, page 39, line 6.
[190] Build Application, Schedule 3, page 28, Table 5.
[191] Hydro September Reply, Question 4, page 10, Table 4.
[192] Build Application, Schedule 3, page 48, Table 9.

underpin the Build Application's requested investments in the BDE Unit 8 and Avalon CT projects.[193] Hydro noted that "the Minimum Investment Required Expansion Plan is the first step to meeting [the Reference Case] requirements."[194] As such, Hydro put forth Scenarios 1AK and 1AEK "[t]o provide a fulsome response" to the Board's directive.[195]

(82) The results of the Reference Case scenarios show that BDE Unit 8 and the Avalon CT are each built in 2031, with Newfoundland Power's gas turbines being selected in 2032. (Additional resources, including BESS (where allowed to be selected) and additional CT capacity, are built in 2033 and beyond.)[196] Hydro also notes the benefits of the Avalon CT – and its location on the Avalon – relative to the off-Avalon Newfoundland Power gas turbines.[197]

(83) The Reference Case scenarios provide additional useful information. First, they show that the PLEXOS model continues to first select projects based in large part on the size of those resources, even if those projects are more expensive. This is a point we make in Section III above, but it is reiterated in Hydro's modeling here. Hydro notes, for example, that despite being more expensive, the model builds "the larger BDE Unit 8" before the Newfoundland Power gas turbines "since its capacity will ultimately be needed anyway."[198] In the Reference Case, which uses a considerably higher forecast of energy demand and peak load, this phenomenon is again observed. The model selects the largest resources first: the 154.4 MW BDE Unit 8 and 141.6 MW Avalon CT in 2031, followed by the 48 MW Newfoundland Power gas turbines in 2032.[199] Second, these runs demonstrate the impact of using the Reference Case, with the model building up to 562 MW of firm capacity by 2033 in Scenario 1AEK (versus 242 MW in 2033 in Scenario 4AEK, which uses the Slow Decarbonization load forecast).[200]

(84) In our view, the capacity expansion model and LIL Shortfall Analysis runs completed by Hydro in response to Question 4 in its September Reply are important. They demonstrate the materiality of the firm capacity contribution of the Newfoundland Power gas turbines, which both reduce and delay the amount of firm capacity needed from other resources. This is a material change to the IIS planning environment that was not captured in the Build Application modeling. The LIL Shortfall Analysis also demonstrates that while the Newfoundland Power gas turbines improve portfolio performance

[193] Hydro September Reply, Question 4, page 14, lines 13 to 18; Build Application, Schedule 3, Appendix A, page iii.
[194] Hydro September Reply, Question 4, page 14, lines 14 to 15.
[195] Hydro September Reply, Question 4, page 14, lines 16 to 18.
[196] Hydro September Reply, Question 4, page 15, Table 8 and Table 9.
[197] Hydro September Reply, Question 4, page 16, lines 3 to 9.
[198] Hydro September Reply, Question 4, page 13, lines 7 to 10.
[199] Hydro September Reply, Question 4, page 15, Table 8 and Table 9.
[200] Hydro September Reply, Question 4, page 15, Table 9; and page 6, Table 3

during an extended LIL bipole outage, they do not alone meet Hydro's LIL shortfall criteria regarding hours of generation shortfall above 100 MW.

IX. Use of Competition to Lower Cost, Risk for Ratepayers

(85) In both our August 30, 2024 assessment of Hydro's 2024 Resource Adequacy Plan[201] and in the Bates White June Expert Report,[202] we recommended that Hydro consider the use of competitive solicitation to mitigate the costs and risks of the development of new energy and capacity resources. In its July Letter, the Board prompted Hydro to provide a response to this recommendation.[203]

(86) In its September Reply, Hydro states that it "explored market purchases" and "initiated a Request for Expression of Interest ('RFEOI') process to investigate third-party supply options."[204]

(87) Regarding "market purchases," Hydro explains that it "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."[205] Regarding market purchases from New England, Hydro identifies structural differences between the New England market (which purchases capacity four years into the future) and Newfoundland that makes New England "not compatible" with the planning requirements for the IIS.[206]

(88) According to Hydro, the RFEOI was issued on July 9, 2025 and invited expressions of interest for the supply of up to 500 GWh/year of firm energy and 150 MW of firm capacity.[207] In its September Reply, Hydro did not provide information regarding the due date for responses to the RFEOI or any responses received.

(89) We confirmed the issuance of the RFEOI, which is publicly available.[208] The bid closing date was September 2.[209] Respondents were invited to provide non-binding pricing information.[210] Seventeen

[201] Vincent Musco, Collin Cain, and Nick Puga, "Assessment of Newfoundland and Labrador Hydro's 2024 Resource Adequacy Plan," Bates White Economic Consulting, August 30, 2024, ("Bates White Assessment of 2024 RRA"), page B-2, Item 33; and page B-3, Item 42.

[202] Bates White June Expert Report, page 15, item 7.

[203] Board July Letter, page 2, item 5.

[204] Hydro September Reply, Question 5, page 1, lines 18 to 19.

[205] Hydro September Reply, Question 5, page 2, lines 2 to 5.

[206] Hydro September Reply, Question 5, page 2, lines 9 to 13.

[207] Hydro September Reply, Question 5, page 2 line 22 to page 3 line 3.

[208] *See*: Newfoundland and Labrador Hydro, "Hydro issues request for expressions of interest for adding capacity and energy resources to the Newfoundland Island system," July 9, 2025, available at: https://nlhydro.com/hydro-issues-request-for-expressions-of-interest-for-adding-capacity-and-energy-resources-to-the-newfoundland-island-system/.

[209] *See*: Newfoundland and Labrador Hydro, Bid Number 103472 LP, available at: https://nlhydro.bidsandtenders.ca/Module/Tenders/en/Tender/Detail/c6d67036-d732-4129-be98-909ee1ae09c9.

[210] Newfoundland and Labrador Hydro, "Request for Expressions of Interest for Energy and Capacity Supply," July 9, 2025, Appendix C, Section 2(c), page 19.

responses were received, including from major renewable energy developers, industrial customers, demand-side resource developers, and energy storage companies.[211]

(90) We understand that other than the procurement of new wind generation from third parties, Hydro does not plan to use competitive procurement for the Avalon CT or BDE Unit 8. Given the seemingly robust response to the RFEOI, however, Hydro should seek to introduce and invite competition from third parties in its future resource planning and development activities, and to do so earlier in the process to allow sufficient time for the work required to make third-party projects viable. This should include requests for proposals processes, whereby developers submit *binding* offers to develop new resources or otherwise supply needed firm capacity and energy to Hydro. Hydro should also work to ensure that its methods for evaluating third-party proposals reflect the costs, benefits, and risks of those bids relative to projects developed by Hydro itself. Examples of such procurement mechanisms are readily available and can help to mitigate the cost and risks to Hydro and ratepayers in continuing to transform the resource portfolio that serves the Newfoundland and Labrador Interconnected System ("NLIS").

(91) Lastly, Hydro's schedule of events for pursuing firm capacity may not be optimal. Hydro has indicated through publicly-available questions and answers with interested third parties that the RFEOI "will be followed by a firm energy RFP and a firm capacity [request for information]," where the intent of the firm capacity request for information ("RFI") "is to seek approximately 150 MW of firm capacity" and where "[p]romising proposals will be included as supply options in the 2026 Reliability and Resource Adequacy Study and competed against other resource options to meet the [IIS] requirements."[212] It is not clear that an RFI process for firm capacity will be worth the time investment and delay, given that the RFEOI process already invited non-binding offers to provide up to 150 MW of firm capacity. Moreover, it would be a suboptimal outcome if Hydro used RFI responses to preclude an RFP process for firm capacity by "competing" these RFI responses "against other resource options" in the 2026 RRAS study process.[213] A better alternative may be to invite offers through an RFP for firm capacity, whereby Hydro can compare and evaluate *binding* offers to provide firm capacity by third parties and Hydro-sponsored options. We recommend Hydro revisit its planned approach going forward.

[211] *See*: Newfoundland and Labrador Hydro, Bid Number 103472 LP, available at: https://nlhydro.bidsandtenders.ca/Module/Tenders/en/Tender/Detail/c6d67036-d732-4129-be98-909ee1ae09e9.

[212] Newfoundland and Labrador Hydro, "Re: 103472 LP RFEI Energy and Capacity Supply Clarification No. 1," August 22, 2025, page 2, Question 4.

[213] Newfoundland and Labrador Hydro, "Re: 103472 LP RFEI Energy and Capacity Supply Clarification No. 1," August 22, 2025, page 2, Question 4.

X. Hydro has satisfactorily corrected certain errors in the Build Application

(92) In the Bates White June Expert Report, we identified an inconsistency in Hydro's calculation of management reserve.[214] In its July Letter, the Board prompted Hydro to provide a response to this inconsistency, including any needed recalculation of the net present value calculations for the capacity expansion modeling runs accounting for the corrected management reserve values.[215]

(93) In its September Reply, Hydro confirmed the inconsistency and provided updated costs of firm capacity for both BDE Unit 8 and the Avalon CT.[216] Those updated numbers are shown in Table 7 below.

Table 7: Corrected $/kW Cost of BDE Unit 8, Avalon CT[217]

Resource	Build Application Cost ($/kW)	Updated Cost ($/kW)	Increase ($/kW)	Increase (%)
BDE Unit 8	6,990	7,184	+194	2.8%
Avalon CT	6,295	6,454	+159	2.5%

(94) Hydro acknowledges that the updated cost data increased "the total authorized cost by less than 3% overall," but Hydro states that it is not adjusting its requested budget for either project to reflect these corrected values.[218] Hydro also incorporated the updated cost data into its capacity expansion model runs[219] summarized elsewhere in this report.

(95) In our view, Hydro has adequately responded to our recommendation and the Board's request.

(96) Separately, we also pointed out certain discrepancies between load forecast figures presented in the Build Application and numerical data provided in Hydro's 2023 and 2024 load forecast reports.[220] The Board requested that Hydro address the load forecast discrepancy.[221]

(97) In its September Reply, Hydro explained that it "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]."[222] Hydro confirmed that the correct load forecasts were used in the modeling work

[214] Bates White June Expert Report, pages 46 paragraph 95 to page 48 paragraph 97; and page 47, Table 8.
[215] Board July Letter, page 3, item 6.
[216] Hydro September Reply, Question 6.
[217] Hydro September Reply, Question 6, page 1, Table 1.
[218] Hydro September Reply, Question 6, page 1, line 15.
[219] Hydro September Reply, Question 2a), page 5, footnote 7.
[220] Bates White June Expert Report, pages 21 paragraph 31 to page 23 paragraph 34; and page 23, Figure 2.
[221] Board July Letter, page 3, item 7.
[222] Hydro September Reply, Question 7, page 1, lines 6 to 8.

underpinning the Build Application and provided corrected data related to the 2024 load forecast.[223] In our view, Hydro adequately responded to this directive. However, we note that factors with significant potential impact on projected load have changed since the most recent forecast was developed. One notable example is changes to both federal and provincial electric vehicle support programs in 2025. Updating load forecasts with specific reference to such changed factors will be a critical element of Hydro's 2026 planning process.

[223] Hydro September Reply, Question 7, page 1, lines 10 to 13.

XI. Consideration of Uprate of BDE Unit 7 as Alternative to BDE Unit 8

(98) In our August 30, 2024 assessment of Hydro's 2024 Resource Adequacy Plan,[224] we recommended that Hydro explain how the potential uprate of BDE Unit 7 is impacted by the inclusion of BDE Unit 8 in the recommended expansion portfolio. In its July Letter, the Board addressed the potential uprate of BDE Unit 7, stating:

> 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? 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.[225]

(99) In its September Reply, Hydro stated that it did not "see merit" in including a capacity increase to BDE Unit 7 for three reasons.[226]

(100) First, Hydro cited a conclusion of the Hatch Uprate Report regarding hydrological limitations; Hatch stated in 2024 that "[s]ince there is a finite amount of hydraulic capacity available in the [BDE] 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."[227] Hydro stated that "[t]he Hydrology and Feasibility Study for the Potential [BDE Unit 8], completed by Hatch and filed with the 2025 Build Application, confirmed the optimized generating capacity increase at the BDE plant is 150.1 MW with the addition of BDE Unit 8."[228] Accordingly, "[t]his finding establishes a limit on efficient incremental capacity available in the BDE system, for consideration across both Unit 7 and the planned Unit 8."[229] Hydro continued that "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; resulting in increased water usage in a hydrologically constrained system."[230]

(101) Second, Hydro asserts that a BDE Unit 7 uprate would cause delays for both BDE Unit 7 and BDE Unit 8 projects. Hydro states that "[p]ursuing a capacity increase for Unit 7 would require substantial additional engineering and design work to confirm the technical viability of the project and the

[224] Bates White Assessment of 2024 RRA, page B-3, item 36.

[225] Board July Letter, page 3 item 8.

[226] Hydro September Reply, Question 8, page 1, lines 8 to 9.

[227] Hydro September Reply, Question 8, page 1, lines 19 to 22 (footnote omitted).

[228] Hydro September Reply, Question 8, page 2, lines 1 to 4 (footnote omitted).

[229] Hydro September Reply, Question 8, page 2, lines 10 to 12.

[230] Hydro September Reply, Question 8, page 2, lines 13 to 15 (footnote omitted).

potential megawatt available in the uprate" which "would delay the start of the Unit 7 life extension project by two years."[231] The expected in-service date under this scenario for Unit 7 would be the fourth quarter of 2031;[232] Hydro notes that the "2023 Condition Assessment concluded that refurbishment of Unit 7 is required by 2029 to ensure its continued reliability."[233] Finally, Hydro stated that "[a]s 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," which would require re-engineering of BDE Unit 8 and would further delay both the BDE Unit 7 and BDE Unit 8 projects.[234]

(102) Third, Hydro claims that the uprate to BDE Unit 7 would increase costs and harm reliability. Hydro claims that delaying work on BDE Unit 7 and BDE Unit 8 would increase construction costs as a result of escalation and "increasing market pressure;" Hydro estimates that the delays would increase the cost of BDE Unit 8 by an estimated $30-50 million per year of delay.[235] Hydro states, too, that "a decision to pursue an uprate would also affect the broader system" as "[p]rojects identified for completion in Hydro's five-year capital plan could be impacted through changes in sequencing, outage planning, and resourcing."[236] Thus, Hydro concludes that its "recommended approach is to proceed with the life extension of Unit 7…to maintain system reliability in the near-term while enabling the full capacity development of Unit 8."[237]

(103) There is an ongoing, separate proceeding in which additional and relevant evidence has been filed by Hydro related to this issue, and while we have not undertaken a complete review of all materials in that matter, we note the following. In the BDE 7 Life Extension matter before the Board, Hydro has filed additional evidence suggesting an uprate of Unit 7 is not optimal. This included a 2004 report by General Electric ("GE Report"), which assessed the costs and benefits of a replacement runner for BDE Unit 7.[238] The GE Report concluded that the uprate would result in an increase of just 5 MW.[239] The GE Report explains:

> As an illustration of the significance of [Figure 3], what it indicates is that we could make use of 15 MW of additional MW of capacity only 20% of the time and 5 additional MW of capacity 90% of the time. The limitations inherent in the design of the proposed runner are apparent from this curve, especially when one considers that high tide will not necessarily coincide with system peak, which is when the additional capacity offered by the proposed runner would be of most use…To summarize, although GE Hydro has offered a runner with

[231] Hydro September Reply, Question 8, page 2, lines 23 to 26.

[232] Hydro September Reply, Question 8, page 3, lines 1 to 2.

[233] Hydro September Reply, Question 8, page 3, lines 2 to 3.

[234] Hydro September Reply, Question 8, page 3, lines 6 to 9.

[235] Hydro September Reply, Question 8, page 3, lines 11 to 17.

[236] Hydro September Reply, Question 8, page 3, lines 22 to 24.

[237] Hydro September Reply, Question 8, page 4, lines 1 to 3.

[238] Newfoundland and Labrador Hydro, "Bay d'Espoir Unit 7 Additional Analysis Report," September 22, 2025 (as revised September 23, 2025), Attachment 2 ("GE Report").

[239] GE Report, page 6.

> greater capacity, tail water elevation severely limits the usefulness of this additional capacity…The amount of additional capacity offered is considered to be 5 MW.[240]

(104) We also recognize that the scheduled work on BDE Unit 7 and the construction of BDE Unit 8 are interdependent; schedule delays suffered by one project may negatively impact the schedule of the other. For example, the BDE Unit 7 life extension work takes place between April 1, 2028 and October 31, 2028, during which time BDE Unit 7 will be out of service.[241] Meanwhile, start of construction for BDE Unit 8 is specified in the Build Application as April 4, 2028,[242] i.e., at the beginning of BDE Unit 7's 2028 outage window. Concurrent work at BDE Units 7 and 8 during 2028 will likely require coordination and, in the event of delays for one project, could impact the schedule of the other.

(105) In our view, Hydro has raised material concerns regarding the efficacy of an uprate to BDE Unit 7. The GE Report suggests that tailwater issues would limit the uprate to as little as 5 MW, and Hydro has since confirmed that "considerations regarding tailwater elevation remain valid from a technical perspective" but "would require detailed feasibility assessment and engineering analysis to quantify their present-day impacts."[243] Moreover, Hydro (and Hatch) suggest that due to hydrological constraints, 150.1 MW is the optimal incremental increase for BDE as a plant, meaning that if Hydro was to pursue both an uprate of BDE Unit 7 and the building of BDE Unit 8, a smaller capacity BDE Unit 8 would be more optimal. Should the Board not approve BDE Unit 8 in this proceeding, the issue of BDE Unit 7's uprate could be fully assessed in the BDE Unit 7 Life Extension matter. Such an assessment should explore whether the maximum uprate capacity remains 5 MW.

[240] GE Report, page 6.

[241] Newfoundland and Labrador Hydro, "Application for Capital Expenditures for the Life Extension of Bay d'Espoir Unit 7," Schedule 1, Attachment 3, page 13, Figure 3.

[242] Build Application, Schedule 4, Appendix B, page B-1.

[243] Newfoundland and Labrador Hydro, "Application for Capital Expenditures for the Life Extension of Bay d'Espoir Unit 7 – Request for Additional Information – Hydro's Reply," October 16, 2025, page 2.

XII. Bates White's Key Conclusions and Recommendations

(106) The additional information, data, analysis, and narratives provided by Hydro in its September Reply have substantially enhanced the record and will assist stakeholders and the Board in completing review of the Build Application. In our view, Hydro's September Reply fully addresses and resolves several outstanding issues raised either in the Bates White June Expert Report or the Board's July Letter, detailed in our report above.

(107) As the Build Application review process proceeds, and Hydro continues its longer-term planning efforts, we offer the following observations:

- Hydro's additional capacity expansion modeling demonstrates that Bay d'Espoir Unit 8 and the Avalon CT are similar in cost. When the forced fuel-burn off requirement at the Avalon CT is removed, the Avalon CT is lower cost but is selected after BDE Unit 8 due solely to the 12.8 MW greater modeled firm capacity of BDE 8. Building BDE Unit 8 first delays build of the Avalon CT by one year, providing cost savings of approximately 0.4% on a net present value basis, relative to building the Avalon CT first.

- Hydro has provided evidence that the BDE system can sustain a level of output from BDE Units 1-8 similar to that modeled in the LIL Shortfall Analysis as part of the Build Application. Results depend on assumptions about (a) reservoir storage levels, (b) average inflows, and (c) significant spill activity that could be less favorable than assumed, which could increase the risk of hydrological shortages in the BDE system either during a six-week LIL bipole outage or in the aftermath of such an event.

- Hydro has demonstrated that the existing transmission grid is sufficient to allow for power flows from Bay d'Espoir to the Avalon peninsula during normal operating conditions and single contingencies, which does not include an extended outage of the LIL bipole. We are currently reviewing Hydro's assessment of the effectiveness of a remedial action scheme during extended LIL bipole outages and will provide our assessment in our final and forthcoming expert report in this proceeding.

- Newfoundland Power's plan to extend the lives of certain thermal generating assets would provide significant firm capacity that reduces and/or delays the need for additional firm capacity on the IIS.

- BESS resources are shown to be economic when BDE Unit 8 and the Avalon CT are modeled at their full requested authorized budgets and provide meaningful contributions during an extended outage of the LIL bipole.

- The response to Hydro's REFOI process suggests potentially robust interest in third-party willingness to supply firm energy and capacity to the province.

- Hydro has demonstrated that if the Avalon CT or BDE Unit 8 were delayed to commercial operation dates beyond 2031, the IIS would not suffer from a generation shortfall as long as Hydro's existing thermal assets remain operational.

- Several key issues should be addressed in the remainder of the Build Application process. These include (1) the validity of the modeled fuel burn-off requirement at the Avalon CT, (2) the impact of using a remedial action scheme to manage capacity transfer limitations on the Bay d'Espoir to Soldiers Pond transmission corridor, (3) cost considerations for both the Avalon CT and BDE Unit 8 projects, including any updates to cost estimates driven by procurement activities Hydro is currently pursuing on both projects, and (4) incorporation of any updates regarding the planned refurbishment and possible uprate of BDE Unit 7.

(108) We also offer the following recommendations:

- **Recommendation 1:** Going forward, BESS resources should be considered as viable resources in future Hydro resource planning decisions, should resource needs persist (such as Hydro claims regarding the implications of applying Hydro's Reference Case load forecast).

- **Recommendation 2:** We continue to recommend that Hydro seek to introduce and invite competition from third parties in its future resource planning and development activities, and to do so earlier in the process to allow sufficient time for the work required to make third-party projects viable.

- **Recommendation 3:** Hydro will need prudent investment planning to balance the risk of underinvesting in its existing assets that may be needed longer than expected against overinvesting in assets about to retire.

Appendix A. Matrix of scenarios referenced in this report

Table 8: Matrix of scenarios referenced in this report[244]

Scenario	Load Forecast	Description
1AEK	Reference	Fixed wind profile to meet firm energy criteria Remove Batteries as a resource option Include Newfoundland Power GT additions
1AK	Reference	Fixed wind profile to meet firm energy criteria Include Newfoundland Power GT additions
4A	Slow Decarbonization	Fixed wind profile to meet firm energy criteria
4AC	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove forced Avalon CT fuel burn-off
4ADH	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Increase BDE Unit 8 and Avalon CT costs to P85
4AEF	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW
4AEF (ADV)	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Advance second capacity resource from 2034 to 2031
4AEFC	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Remove forced Avalon CT fuel burn-off
4AEFDH	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Restrict CT additions to maximum of 150 MW Increase BDE Unit 8 and Avalon CT costs to P85
4AEK	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Remove batteries as a resource option Include Newfoundland Power GT additions
4AK	Slow Decarbonization	Fixed wind profile to meet firm energy criteria Include Newfoundland Power GT additions

[244] Hydro, "2024 Resource Adequacy Plan," July 9, 2024, Appendix C, page 54, Table 5; Hydro September Reply, Question 2a), page 2, lines 12 to 15; Hydro September Reply, Question 4, page 1, lines 17 to 18.