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 REPORT OF VINCENT MUSCO AND COLLIN CAIN

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Abbreviations and defined terms used in report

2023 RRA – 2023 Reliability and Resource Adequacy Study

2024 Load Forecast Report – Long-Term Load Forecast Report

2024 RAP – 2024 Resource Adequacy Plan

AACE -- Association for the Advancement of Cost Engineering

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

BDE-SOP -- Bay d'Espoir to Soldiers Pond 230 kV transmission system

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

CAGR – Compound Annual Growth Rate

CT – Combustion Turbine

DDA – Design Development Allowance

ELCC – Electric Load Carrying Capability

EqFOR – Equivalent Forced Outage Rate

EV – Electric Vehicle

FEED – Front-End Engineering Design

FOM – Fixed operations and maintenance

GT – Gas Turbine

Holyrood TGS – Holyrood Thermal Generation Station

Hydro – Newfoundland Labrador Hydro

IIS – Newfoundland Island Interconnected System

Industrial Customers – Island Industrial Customer Group

IR – Information Request

ITC – Clean Energy Investment Tax Credit

LIL – Labrador Island Link

LIS – Labrador Interconnected System

LOLE – Loss of Load Expectation

LOLH – Loss-of-load-hours

MC – Monte Carlo

MCM – Million cubic meters

MR – Management Reserve

Muskrat Falls – Muskrat Falls Generating Station

NERC – North American Electric Reliability Corporation

Newfoundland Power, NP – Newfoundland Power Inc.

NLIS – Newfoundland and Labrador Interconnected System

NREL – National Renewable Energy Labs

O&M – Operating and maintenance

RFI – Request for information

TransGrid – TransGrid Solutions

VOM – Variable operations and maintenance

I. Introduction and Background

A. Bates White's role and qualifications

(1) 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 support the Reliability and Resource Adequacy Review in November of 2023. Specifically, Bates White was retained to assess the reliability and resource adequacy of the Newfoundland and Labrador Interconnected System ("NLIS"), considering especially the impacts of electrification, clean electricity regulations, evolving resource and technological potential in the Province, and the operational uncertainty of existing supply and transmission resources in the Province, including Muskrat Falls Generating Station ("Muskrat Falls") and the Labrador Island Link ("LIL"). Bates White was retained to provide Expert Consulting services to the Board regarding the Build Application filed by Newfoundland Labrador Hydro ("Hydro"), including advising the Board on the Build Application's relation to the 2024 Resource Adequacy Plan ("2024 RAP").[1]

(2) After being retained by the Board, Bates White reviewed Newfoundland Hydro's Long-Term Load Forecast, filed on March 28, 2024. Bates White reviewed this filing and submitted Information Requests ("IRs") to Hydro before filing an expert assessment with the Board on July 25, 2024. Bates White subsequently assessed Hydro's 2024 RAP. Bates White filed an expert assessment of the 2024 RAP with the Board on August 30, 2024, providing over sixty action items for Hydro to consider before moving forward in the resource planning process. Hydro addressed these items in Technical Conferences with Bates White and other stakeholder parties. Bates White continued to participate in the development and assessment of the 2024 RAP after these conferences by filing IRs with Hydro in November of 2024. Bates White hosted additional calls with Newfoundland Hydro following these meetings and IRs to review specific matters of interest which were critical to assessment of the 2024 RAP. These IRs, Technical Conferences, and meetings provided a basis for Bates White to review and provide feedback to a proposed settlement agreement between Hydro, the Board, and stakeholder parties, which would be filed in March of 2025.

(3) Bates White has continued to provide expert consulting to the Board in review of Hydro's 2025 "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine" ("Build Application"), filed on March 21, 2025. Bates White hosted numerous calls with Hydro to review the Build Application and all inputs which pertain to the 2024 RAP and the 2024 Load Forecast. Bates White submitted additional IRs, to which Hydro responded on a rolling basis through May 2025. These meetings and IRs with Hydro, along with the Build

[1] Hydro, "Reliability and Resource Adequacy Study Review – 2024 Resource Adequacy Plan," July 9, 2024 (*hereinafter* "2024 RAP").

Application itself and all previous meetings and expert consulting materials provided by Bates White provide the basis for our review of this Build Application. In this report, any information we received from Hydro subsequent to the March 21, 2025 are filing date of the Build Application is cited in footnotes as "Information Provided to Bates White."

(4) This evidence is sponsored by Vincent Musco and Collin Cain, both Partners at Bates White. The *curricula vitae* for Mr. Musco and Mr. Cain are attached as Appendix A and B.

B. Background and Brief Summary of Build Application

(5) On March 21, 2025, Hydro submitted the Build Application.[2] The Build Application principally seeks approval of capital expenditures related to the purchase and installation of the Bay d'Espoir Unit 8 ("BDE Unit 8") and the Avalon Combustion Turbine ("Avalon CT"). This application follows the 2024 RAP, filed July 9, 2024, which examined system needs on the Newfoundland Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS"). Bates White filed an assessment of the 2024 RAP with the Board on August 30, 2024.[3]

(6) The 2024 RAP provided results for approximately 30 capacity expansion model runs using PLEXOS, culminating in Hydro recommending the "Minimum Investment Required Expansion Plan" portfolio, which included the development of BDE Unit 8, the Avalon CT, and a total of 400 MW of new wind generation by 2034.[4] Following Hydro's filing of the 2024 RAP, parties including Bates White, Hydro, the Consumer Advocate, Newfoundland Power Inc. ("Newfoundland Power", or "NP"), and the Island Industrial Customer Group ("Industrial Customers") met in rounds of technical conferences and written discoveries to further review the 2024 RAP and prepare a Settlement Agreement.

(7) 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"[5] of $1.08 billion.[6] BDE Unit 8 is proposed to have an "anticipated completion"

[2] Hydro, "Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Redacted," March 21, 2025 (hereinafter "Build Application").

[3] 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 (hereinafter "Bates White Assessment of 2024 RRA").

[4] 2024 RAP, Section 8.1 and Table 54.

[5] The Authorized Budget includes capital cost estimates, interest during construction, escalation, and a management reserve. Build Application, Application, paragraph 13.

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

date in 2031.[7] Second, Hydro seeks approval for the 150 MW Avalon CT, including an Authorized Budget of $891 million.[8] The anticipated completion date is stated as "late 2029."[9]

(8) This expert report provides a review of the Build Application. The report is structured as follows:

1) Executive summary.

2) An assessment of Hydro's modeling work underpinning the Build Application, including the load forecast, resource planning criteria, assumptions and modeling of existing generation and transmission assets, and modeled supply resource options.

3) An assessment Hydro's overall capacity expansion modeling approach, as well as the selected set of scenarios and sensitivities. We also review Hydro's approach to modeling a scenario of an extended outage on the Labrador Island Link.

4) Assessment of the modeling results and recommended portfolio of resources put forth by Hydro.

5) A set of recommendations for consideration.

[7] Build Application, Application, page 3 paragraph 13.
[8] Build Application, Application, page 3 paragraph 14.
[9] Build Application, Application, page 3 paragraph 14.

II. Executive Summary

(9) Hydro's Build Application is the culmination of a lengthy and significant planning effort that began as early as 2018. Hydro has engaged industry experts, industry standard planning tools and methods, and provided substantial opportunity for interested parties to review and assess its planning efforts, assumptions, and results.

(10) The Build Application seeks authorization for $1.97 billion of investments to be recovered from ratepayers who are already paying $13.5 billion of costs associated with Muskrat Falls and associated transmission assets, including the LIL. Hydro acknowledges that it is currently subject to a rate mitigation plan, and that it "will work with the Government" to "determine future rate mitigation requirements once more information on the landscape of the electricity sector" for 2030 and beyond is known.[10] Given the substantial investment involved, and the province's rate mitigation plan,[11] it is particularly important that the requested investments in the Build Application are thoroughly vetted.

(11) Further, while Hydro's requested "authorized budgets" for the two projects total $1.97 billion and includes AACE[12] Class 3 estimates at an 85% confidence level, the authorized budgets are estimates, not cost caps. Delays and cost overruns can impact these projects and would subject ratepayers to additional potential costs and delayed benefits. Moreover, the projects put forth by Hydro for approval were not the product of a competitive solicitation, where participants (including Hydro) would offer their best proposal for a new resource, which could have the benefit of identifying the best deal for ratepayers in terms of cost, benefit, and risk. Instead, the projects and costs proposed here were developed by Hydro, albeit with assistance from outside specialized firms.

(12) Our review of the Build Application in this report is limited to its relation to Hydro's planning efforts completed in 2024, as best memorialized in Hydro's 2024 RAP. Beyond our scope in this report, much work remains, including detailed assessment of Hydro's cost estimates, project schedules, and project management protocols. In this report, as it relates to our scope of work, we find:

- Hydro's load forecast assessed a reasonable range of demand projections, subject to the following caveats. First, the Slow Decarbonization forecast, while a reasonable scenario for consideration in the Build Application, is not the lowest plausible load scenario over the planning horizon; lower population growth, lower EV adoption rates and lower industrial load growth are possible and could coincide. Second, the Reference Case remains subject to significant uncertainty and should be monitored and updated, particularly since it implies additional investment may be needed beyond BDE 8 and the Avalon CT. Third, the Load

[10] Build Application, Schedule 3, Appendix A, page 4 line 23 to page 5 line 5.

[11] Build Application, Schedule 3, Appendix A, page 4 line 23.

[12] Association for the Advancement of Cost Engineering.

Forecast contained a potential small discrepancy, in which reported numerical data do not correspond to charts in the Build Application. This is discussed in Section III.B below.

- Hydro was reasonable in selecting a resource planning criterion of 2.8 loss of load hours ("LOLH") per year given the large, estimated cost ($2.3 billion) of meeting a more stringent target. Hydro has introduced an additional resource planning criterion designed to assess its resource portfolio's performance during a six-week bipole outage of the LIL during peak winter months. This criterion has substantial impact on Hydro's recommended plan resources, as it is a reason for advancing the in-service year of one of the firm capacity resources to 2031 (to match the other) and was the partial basis for ignoring battery energy storage systems ("BESS") in the system modeling supporting the Build Application.

- Hydro appropriately represented the operating characteristics of the existing generating fleet in the modeling underpinning its Build Application. Still, some assumptions are worth noting. First, Hydro's modeling assumes that 618 MW of existing, thermal firm capacity (including the 490 MW Holyrood Thermal Generating Station ("Holyrood TGS")) will retire by 2030. However, under the conditions set forth by Hydro, these resources will not retire until sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. Delays in thermal retirements – regardless of their cause – will impose additional costs; for example, Hydro estimates the cost of continued operation of Holyrood TGS would average $138.4 million per year from 2030 to 2035.

- The LIL Equivalent Forced Outage Rate has been modeled reasonably at an assumed range between 1% and 10%. The original expected equivalent forced outage rate of the LIL (0.0114%) is not a realistic assumption going forward, given the equivalent forced outage rates observed on the LIL to date (4% in 2023 and 3.37% in 2024). While Hydro is pursuing remedial actions to improve LIL performance, Hydro has stated that the current remedial work Hydro is pursuing for the LIL will, at best, result in an expected LIL equivalent forced outage rate of 1%. As the LIL equivalent forced outage rate increases from 1% to 5%, the cost of incremental resources needed to maintain reliability criteria is an additional $2.3 billion. A 10% LIL forced outage rate increases that figure another $1.2 billion to $3.5 billion.

- The 230 kV Bay d'Espoir-Soldiers Pond transmission segment is currently limited to 680 MW (normal operations) or 603 MW (during a LIL bipole outage), which can limit the maximum collective output of the existing Bay d'Espoir units 1-7 (613 MW). Absent transmission solutions, this constraint prevents transmission of *any* incremental output from BDE 8 during a LIL bipole outage, exactly when that output is needed most. Even during normal operations with the LIL in service, just a fraction (67 MW out of 154.4 MW) of the incremental output from BDE 8 is deliverable. While Hydro has identified one solution (estimated cost: $150 million) and is studying others, no solutions are put forth in the Build Application.

- The Class 3 cost estimates for BDE 8 and the Avalon CT have increased by [redacted] and [redacted], respectively, over the Class 5 estimates used in the 2024 RAP, before including the costs of escalation, interest during construction, and a Management Reserve. The cost estimate of BDE 8 is incomplete and understates cost of resource, since it ignores the cost of the transmission solution investment needed to resolve the Bay d'Espoir-Soldiers Pond transmission constraint. The Avalon CT may have been overestimated on an NPV basis and was modeled assuming a "worst case scenario" requiring substantial, perpetual, uneconomic fuel burn-off costs; for example, we observed that about 16% of the Avalon CT's fuel burn-off costs accounted for in the modeling effectively occur *after* the end of the unit's 35-year asset life in 2065.

- We believe there is a problem in the way Management Reserves ("MR") for BDE8 and the Avalon CT have been determined. The Monte Carlo ("MC") analysis for both resources, which determined the MR, did not include escalation and interest during construction, thereby understating the full estimated cost. Hydro should recalculate the NPVs of the results for the capacity expansion modeling runs to address this. We estimate that the correction would increase the respective Management Reserves, and Authorized Budgets, by [redacted] million for BDE 8 and [redacted] million for the Avalon CT.

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

- Hydro's updated Expansion Plan scenarios represent a reasonable range of future conditions to assess the Build Application. Moreover, Hydro's decision to update only Scenarios 1 and 4 was, in our view, reasonable, given the insights derived from the 2024 RAP capacity expansion modeling, which evaluated a full set of eight scenarios.

- Hydro's capacity expansion model sensitivities represent a useful, albeit potentially incomplete, set of assumptions, as elaborated in the following comments:

  - BESS resources were excluded from all capacity expansion modeling in the Build Application. The 2024 RAP capacity expansion modeling runs showed that BESS resources were selected when included in PLEXOS and when effective load carrying capabilities ("ELCCs") were assumed 60% or higher.

  - Hydro imposed a 150 MW limit for new CT capacity on the Avalon due to fuel constraints. This precluded any assessment of the costs and benefits of fuel supply infrastructure investments, which could allow for additional CT capacity on the Avalon.

  - Hydro limited the minimum build size of new CT capacity to 150 MWs, despite recognizing that individual CT units are likely to be about 50 MW in size. This prevented consideration of expansion plans that mixed and matched smaller CT configurations, including with BESS resources.

  - Hydro's selected sensitivities do not include a review of the impact of delayed retirements at its existing thermal generating stations, including Holyrood TGS. Such delays could be caused by schedule delays for the Avalon CT and/or BDE 8, as well as high and/or volatile equivalent forced outage rates on the LIL. Such sensitivities are likely unnecessary, as they would only demonstrate higher costs or delayed replacement resource selections, and no parties are suggesting a reasonable scenario where Holyrood TGS is intentionally extended beyond 2030.

- The LIL Shortfall Analysis is an important exercise and its results constitute the primary basis for Hydro's proposal to advance the Avalon CT project to 2031. Before drawing conclusions from the LIL Shortfall Analysis results, the following modeling characteristics and assumptions should be considered:

  - The LIL Shortfall Analysis may overstate the reliability contribution of BDE 8 during an extended bipole outage of the LIL. The LIL Shortfall Analysis results assume output that is 34 percent higher than the *highest* six-week output from the collective plant since 2015; moreover, 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.

  - The LIL Shortfall Analysis does not consider transmission constraints, which Hydro expressly acknowledges in the Build Application. This overstates the current ability of the system to receive output from Bay d'Espoir and consequently overstates the incremental contribution of BDE 8, absent additional transmission investments.

  - The LIL Shortfall Analysis assumes no constraints associated with fueling the Avalon CT, which may be an aggressive assumption. While Hydro's proposed tank infrastructure capacity is sufficient to cover maximum consumption implied by the LIL Shortfall Analysis results, Hydro may need to refuel the Avalon CT during the outage if the Avalon CT is less efficient than assumed or if the LIL bipole outage lasts longer than six weeks. Such a need for refueling would be subject to risk.

  - Like the capacity expansion modeling, the LIL Shortfall Analysis does not assess the efficacy or value of BESS resources. Hydro's limited assessment of BESS resources in the 2024 RAP suggests that the contribution of BESS is, under some assumptions, similar to that of an individual CT unit.

  - The LIL Shortfall Analysis asserts that 100 MW of rotating outages is a manageable level of load shed during a LIL bipole outage. The management of outages would largely fall to Newfoundland Power, not Hydro, and thus it would be beneficial to receive confirmation in this proceeding from Newfoundland Power confirming its confidence in the ability to successfully rotate 100 MW of outages, or conceivably more. The 100 MW outage level was based on experience during the 2014 winter outage. It would be useful to know whether, and how, changes in the interim have affected this capability.

  - No LIL Shortfall Analysis model runs assessed the impact of Hydro's existing thermal assets (including Holyrood TGS) remaining online through 2032, the representative year used in the analysis. Given the risk that Holyrood TGS will remain online beyond its modeled 2030 retirement date, it would be helpful to understand the impact of having the thermal units available during an extended LIL bipole outage.

- Hydro has adequately addressed most of the 63 recommendations we included in our Assessment of 2024 RRA. For others, work remains to be done, which we detail in section III.I of our report. Additionally, the Build Application's content appears consistent with the eleven "Settled Issues" identified in the RAP Settlement Agreement. We observed no evidence from the Build Application that contravenes any of the Settled Issues.

- Hydro has, in our view, successfully demonstrated that there is a need for firm capacity by 2035, assuming the concurrent retirement of the Holyrood TGS, Stephenville GT, and Hardwoods GT. Hydro has used the most conservative load forecast (Slow Decarbonization) and most aggressive LIL equivalent forced outage rate (1%) to identify the "minimum investment" needed to meet its selected planning criterion of 2.8 LOLH. Hydro's capacity expansion modeling (Scenario 4AEF) clearly shows a need for firm capacity by 2035, with some required online by 2031.

- These results are contingent on the retirement of 618 MW of existing thermal generation, particularly Holyrood TGS, which currently provides 490 MW of capacity. *Absent these retirements, there is no demonstrated need for this level of new capacity*. Should these retirements be delayed, Hydro's modeling suggests that the system would have excess capacity. The adequacy of these investments to meet capacity needs in 2031 and beyond are also dependent on the performance of the LIL. Should the LIL underperform, Hydro's necessary planning reserve margin to maintain a 2.8 LOLH resource planning criterion would increase, bringing with it additional capacity investment and ratepayer costs.

- Hydro's proposed advancement of one of the firm capacity resources to 2031 (to match the timing of the other) is driven in part by the results of the LIL Shortfall Analysis. Having both resources in service by 2031 is a form of insurance against severe impacts from an extended LIL bipole outage during peak season. The incremental cost of this insurance (i.e., advancing one firm capacity resource to match the other's in-service date of 2031) is approximately $0.2 billion on an NPV basis, according to Hydro's modeling.

- Of the two resources in the Build Application, the selection of the Avalon CT is better supported, while BDE 8 carries with it certain risks and costs that were not fully considered in Hydro's modeling or vetted against potential alternatives.

(13) In recognition of our findings and conclusions, we offer the following recommendations:

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

(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.

(3) Hydro should conduct capacity expansion model runs that include BESS resources of 4-hour and 8-hour duration, assuming 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 8 and the Avalon CT.

- Collectively, 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 CT constraints and BESS prohibition and should be conducted across the three Scenarios identified in Recommendation 3.

(4) Hydro should conduct one 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 Bay d'Espoir to match potential hydrological resource constraints identified in section III.H. 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 TGS, Stephenville GT, and Hardwoods GT are not retired, the Avalon CT is in service, and BDE 8 is not in service.

- Collectively, 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 in which reported numerical data do not correspond to charts in the Build Application.

III. Assessment of Hydro's Modeling

A. Framing the Build Application Relative to the 2024 RAP Study Review Proceeding

(14) Hydro filed two key documents in 2024 as part of its ongoing RRA Study Review process. The Long-Term Load Forecast Report ("2024 Load Forecast Report"), which was filed on March 28, 2024, provided Hydro's forecast of energy and peak demand through 2034.[13] The 2024 Load Forecast Report included three scenarios: (1) a base case (referred to as the "Reference Case,"); (2) a low case (referred to as the "Slow Decarbonization Path Scenario"); and (3) a high case (or the "Accelerated Decarbonization Path Scenario").[14] The 2024 Resource Adequacy Plan, filed on July 9, 2024, provided "an in-depth analysis of how much electricity customers will need over the next ten years and identifies system requirements," which could include the sustaining of existing Hydro assets and consideration of whether new assets would be required to maintain reliability.[15] The 2024 RAP identified a "Minimum Investment Required Expansion Plan" portfolio that included construction of a new 154 MW hydroelectric unit (Unit 8) at Bay d'Espoir, construction of a new 150 MW combustion turbine ("CT") with renewable fuel capabilities on the Avalon, and integration of 400 MW of installed capacity of wind generation.[16] The Minimum Investment Required Expansion Plan portfolio from the 2024 RAP was based on the Slow Decarbonization Path Scenario from its 2024 Load Forecast Report.[17]

(15) The 2024 Load Forecast Report and 2024 RAP were subject to review proceedings by Board staff, stakeholders, and their respective consultants. This included several sets of written Requests for Information and four technical conferences held in September and October of 2024, the materials for which Hydro included in its Build Application for inclusion on the record of this proceeding.[18] Following these exchanges, on March 12, 2025, the parties[19] reached a settlement agreement ("RAP Settlement Agreement") involving several issues ("Settled Issues").[20]

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[13] Hydro, "Reliability and Resource Adequacy Study Review – Long-Term Load Forecast Report – 2023," March 28, 2024 ("2024 Load Forecast Report").

[14] 2024 Load Forecast Report, page iii lines 7 to 18. Throughout this report, we make citation to specific pages of document attachments, appendices, or schedules. The page numbers used will relate to those of the native attachment, typically found at the bottom right of pages.

[15] Hydro, "Reliability and Resource Adequacy Study Review – 2024 Resource Adequacy Plan," July 9, 2024 ("2024 RAP"), page 1 lines 10 to 13.

[16] 2024 RAP, Plan Overview, page vi, lines 4 to 7.

[17] 2024 RAP, Appendix C, page 140, lines 6 to 7.

[18] Build Application, page 3.

[19] Settlement parties included Hydro, the Consumer Advocate, Newfoundland Power, and the Industrial Customers.

[20] The Settled Issues are found in the Build Application, Schedule 2, Attachment 1. *Hereinafter*, referred to as "RAP Settlement Agreement."

(16) The Build Application, therefore, is an outgrowth of the work completed in 2024 and early 2025. The Build Application contains a load forecast, cost estimation, capacity expansion modeling, and other analysis that, in many cases, represent an update from similar work completed in 2024. As such, it is important to assess the Build Application through the lens of the 2024 Load Forecast Report and 2024 RAP. We therefore reviewed Hydro's Build Application to determine and assess the similarities and differences from the prior cost estimation and modeling work, considering whether the updates are reasonable or raise concern. We also consider the Build Application's treatment of the Settled Issues to determine if the Build Application impacts any of those Settled Issues.

(17) That said, it is also important that the Build Application is reasonable on its own, irrespective of prior matters in the RRA Study Review Proceeding. Hydro is seeking cost recovery from ratepayers totaling $1.971 billion for the BDE Unit 8 and CT investments.[21] These are substantial investments that must be justified by Hydro. The framework for our review considers both, assessing whether the Build Application has stayed faithful to the key aspects of the RRA Study Review Proceeding while also considering whether the Build Application sufficiently supports the requested action from the Board.

B. Load Forecast Review

(18) The expansion plan modeling that supports the Build Application incorporates Hydro's 2024 Load Forecast update, which corresponded closely to the 2023 Load Forecast that was applied in development of the 2024 RAP. Hydro describes the 2024 Load Forecast as reflecting "modest downward adjustments"[22] relative to the 2023 forecast, but asserts that the changes in the updated forecast are "not material in the Reference Case or in the Slow Decarbonization scenario."[23] With respect to the Slow Decarbonization scenario underpinning the Build Application, the 2024 Load Forecast shows an increase in IIS peak demand of 174 MW between 2024 and 2035,[24] an increase of approximately 10.1%,[25] representing a compound annual growth rate ("CAGR") of approximately 0.97%. The slightly moderated 2024 Load Forecast results in IIS peak demand in 2035 that is essentially equal to the level projected for 2034 in the 2023 Load Forecast.[26]

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[21] Build Application, Application, page 3.

[22] Build Application, Schedule 1, page 13, lines 18-19.

[23] Build Application, Schedule 1, page 13, lines 16-17.

[24] Build Application, Schedule 3, page 12, lines 2 to 3.

[25] Build Application, Schedule 3, Appendix A, Attachment 1, Table 4. In the Slow Decarbonation Case, Peak Demand escalates from 1,706 MW in 2025 to 1,879 in 2035.

[26] The 2024 Load Forecast projects Peak Demand of 1,879 MW in 2035; the 2023 Load Forecast projected Peak Demand of 1,856 in 2034. Build Application, Schedule 3, Appendix A, Attachment 1, Table 4; 2023 Load Forecast, Appendix A, Table A-4.

(19) The 2023 and 2024 Load Forecasts also project peak demand for the LIS. As the Build Application addresses reliability needs on the IIS only, we do not address the LIS component of the respective forecasts in this report.

(20) The Reference Case in the 2024 Load Forecast is also essentially unchanged relative to the 2023 Load Forecast, with IIS peak load projected to grow by 236 MW between 2024 and 2035.[27] This would be an increase of approximately 14.0%, or a 1.2% CAGR.[28]

(21) Demand associated with projected adoption of electric vehicles ("EVs") represents the largest component of forecasted IIS peak demand growth in both the Slow Decarbonization and Reference cases. The EV share of peak demand growth is approximately 43% to 44% in both cases.[29] Growth in peak demand from the Industrial sector reflects forecasted increases from existing customers on the order of 15 MW through about 2028,[30] plus an additional post-2028 increase of 10 MW of assumed load from new customers in the Slow Decarbonization case, and 20 MW of new customer load in the Reference case.[31] In both the Slow Decarbonization and Reference cases, Industrial demand growth represents on the order of 15% of total projected peak demand growth through 2035. The remaining component of forecasted peak growth – around 40% to 43% – is from the Residential and General Service (commercial and institutional) sectors, driven by new housing construction combined with electrification of space heating for existing Residential and General Service customers.[32]

(22) The 2023 and 2024 load forecasts also project energy use over the planning horizon, similar in pattern to the projected peak demand growth by sector in each forecast case. The load forecasts also include firm energy projections. We do not address energy growth projections in this report since the Build Application is predicated on the need to meet peak load and associated reliability needs on the IIS.

(23) Bates White assessed the 2023 Load Forecast as part of our RRA review and concluded that "[Hydro] has considered relevant drivers of future peak demand and energy usage, and has generally applied industry standard forecast methods appropriately."[33] This conclusion also applies with respect to the 2024 Load Forecast used in the modeling that supports the Build Application. The other findings and recommendations in the Bates White review of the 2023 Load Forecast also apply with respect to the 2024 Load Forecast.

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[27] Build Application, Schedule 3, Appendix A, Chart 2.

[28] Build Application, Schedule 3, Appendix A, Attachment 1, Table 4.

[29] Build Application, Schedule 3, Appendix A, Chart 2, Chart 3, and Table 5.

[30] Build Application, Schedule 3, Appendix A, page 16, lines 13 to 19 and Chart 8.

[31] Build Application, Schedule 3, Appendix A, page 16, lines 15 to 19.

[32] Build Application, Schedule 3, Appendix A, Table 2.

[33] Bates White, "Assessment of Newfoundland and Labrador Hydro's Long-Term Load Forecast Report – 2023," July 25, 2024, (*hereinafter* "Bates White Review of 2023 Load Forecast") page 40.

(24) Bates White concluded that Hydro's load forecasting methods are consistent with industry standards and that Hydro considered relevant drivers of peak demand and energy usage. At the same time, we concluded that major factors affecting future electricity needs – such as EV adoption, electrification of space heating, industrial demand and population growth – are subject to significant uncertainty. We recommended that Hydro review and update its load forecasts for significant changes as they become evident.

(25) As described above, the 2024 Load Forecast provides an update showing slightly lower peak demand growth, but with no material impact on the evaluation of resource need. While the 2024 Load Forecast addresses our general recommendation for timely updates, it does not incorporate several recommendations made in our review of the 2023 Load Forecast. In particular, we recommended that Hydro should:

- Assess the impacts on the load forecast of flat or falling population, consistent with low provincial population growth scenarios evaluated by Statistics Canada;
- Supplement the Slow Decarbonization case with an assessment of impacts from lower or flat industrial load growth;
- Provide detail on the assumptions and associated forecast impacts of oil-to-electric conversion programs, the ability of customers to retain oil heating systems for backup, and the potential impact of electric backup (i.e. resistive heating) to heat pumps.
- Detail the assumptions underpinning the EV growth projections, including the timing and extent to which growth in charging infrastructure will be achieved.[34]

(26) Hydro advances the Slow Decarbonization load forecast case as supporting the Company's Minimum Investment Required Expansion Plan. This load case *may* be reasonable for the purposes of evaluating expansion plan options for near-term consideration, and this is clearly the position of Hydro. However, it would not be appropriate to conclude that the Slow Decarbonization forecast is the lowest load scenario that is plausible over the planning horizon. Based on our review of the 2023 Load Forecast, there is reasonable basis to conclude that lower population growth, lower EV adoption rates and lower industrial load growth are all possible and could coincide. The absence in the Build Application of an examination of a full range of plausible low load scenarios, and the associated impacts on the expansion plan modeling and the Minimum Investment Required Expansion Plan result, reduces confidence that the particular Slow Decarbonization case advanced by Hydro is in fact reasonable and appropriate to identifying the minimum investment scenario. This is not a fatal flaw for the expansion plan analyses, but modeling a plausible low load case addressing these factors would likely have provided useful information.

[34] Bates White Review of 2023 Load Forecast, pages 40 and 41.

(27) With respect to the Reference Case load forecast, it is reasonable in our view that the Build Application is not assessed on this case. Hydro asserts that the Reference Case "reflects the expected or most likely future scenario based on current information."[35] This characterization – and the associated implication that the Slow Decarbonization Scenario is not "most likely"[36] – leads to the sense in the Build Application that the Minimum Investment Required Expansion Plan is merely an initial step before additional resources must be planned for to meet future needs based on the Reference Case.[37] Based on our review of both the 2023 and 2024 load forecasts, we conclude that load is a critical uncertain factor that should be monitored closely in order to confirm or modify the underlying assumptions regarding trends and timing for load growth on the IIS. A simple illustration of the uncertainty and impact of load growth is that small changes in the Slow Decarbonization scenario between the 2023 and 2024 Load Forecasts – amounting to a reduction in demand by 8 MW as of 2034[38] – caused the resource expansion model to select the Avalon CT in 2035 in the update analysis, rather than 2034, as in the RAP.[39] Small variations in forecasted load also have significant implications for the LIL Shortfall Analysis used to justify the recommended plan (with both BDE Unit 8 and the Avalon CT being brought into service by 2031) reflected in the Build Application. Hydro states that "customer demand represented in the 2024 Load Forecast is slightly higher in 2032 compared to the 2023 Load Forecast, which compounds the shortfall amount that is represented in this updated analysis."[40]

(28) As discussed more fully below, the generation expansion plan modeling of alternative scenarios under the Slow Decarbonization load case identified capacity needs that would be met most economically by building BDE Unit 8 for service beginning in 2031, and the Avalon CT for service beginning in 2035 (one year later than identified in the 2024 RAP analysis). This modeling – in which the PLEXOS software tool was allowed to select an optimal expansion plan – incorporated several central constraints with respect to the IIS over the planning horizon through 2035, including: 1) retire Holyrood TGS in 2030;[41] 2) maintain reliability at no more than 2.8 loss-of-load-hours ("LOLH") per year;[42] and, 3) meet projected firm energy needs.[43] Forecasted peak demand and energy usage are key inputs that the PLEXOS model uses to evaluate generation capacity needs, and the economically

[35] Build Application, Schedule 3, Appendix A, page ii, lines 9 to 12.

[36] Build Application, Schedule 1, page 4 lines 22 to 27.

[37] Build Application, Schedule 1 page 11 lines 3 to 8 and lines 20 to page 12 line 12.

[38] Build Application Schedule 3, page 10.

[39] Build Application Schedule 3, page 28 line 13 to page 29 line 1.

[40] Build Application Schedule 3, footnote 64.

[41] Information Provided to Bates White.

[42] Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. Build Application, Schedule 3, Section 5.2.1.1 and Section 5.2.2.1.

[43] Build Application, Schedule 3, Section 5.2.1.1 and Section 5.2.2.1.

optimal expansion plan. In the absence of modeling additional lower load forecast cases, it is not possible to say what the impacts would be on the optimal expansion plans identified using PLEXOS.

(29) It is important to note that the Minimum Investment Required Expansion Plan presented in the Build Application does not conform to the optimal expansion plans identified with PLEXOS for the Slow Decarbonization load forecast, but rather rests substantially on a separate analysis of resources required to maintain "manageable" load shed during a prolonged bipole outage of the LIL. Based in part on this LIL Shortfall Analysis, which we address in Section III.H of this report, Hydro's Build Application advances the in-service date of the Avalon CT to 2031, coincident with commercial operation of BDE Unit 8.

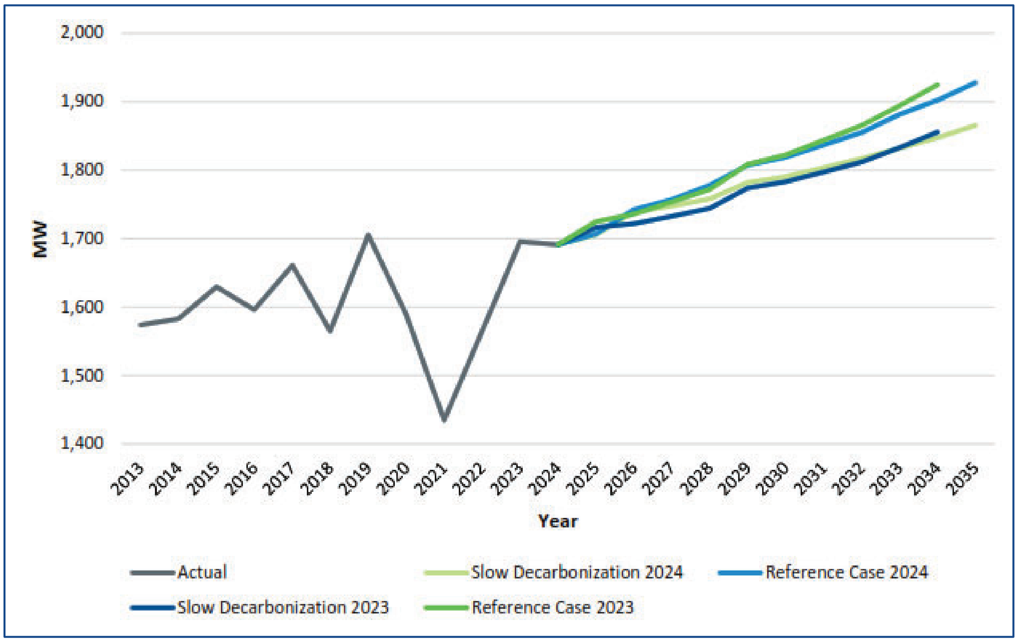
(30) The LIL Shortfall Analysis does not reduce the significance of the load forecast, as the analysis estimates the number of hours and magnitudes of generation shortfalls during an extended LIL bipole outage in 2032, which depend on projected load levels. The analysis of shortfalls under the optimal expansion plan (BDE Unit 8 in 2031 and the Avalon CT in 2035) showed 4% of hours exceeding 100 MW of shortfall during a LIL bipole outage event of "average" severity.[44] Again, it is not known what the result would be of such an analysis with alternative, plausible low load forecast cases. The corresponding results for the Build Application's recommended plan (BDE Unit 8 and the Avalon CT in 2031) show 0.1% of hours exceeding 100 MW of shortfall during an average severity bipole outage.

(31) Bates White identified discrepancies between the load forecast figures presented in the Build Application and numerical data presented in the 2023 and 2024 Load Forecast reports.

(32) Figure 1 reproduces Chart 1 from the 2024 Island Interconnected System Load Forecast Report (included in the Build Application as Appendix A to Schedule 3). The two lower lines on the right side of the chart are: 1) the Slow Decarbonization scenario from the 2023 Load Forecast, in dark blue, and 2) the corresponding load data from the 2024 Load Forecast, in light green. These lines appear consistent with the quoted characterizations by Hydro noted above (i.e., the 2024 Load forecast is lower overall as of 2034, affected timing of the resource selection in that year, but very slightly higher in 2032, affecting the LIL Shortfall Analysis). However, the numerical data provided in the two referenced load forecast reports differ slightly, but noticeably, from the values reflected in Chart 1 of the 2024 Load Forecast Report. The difference is shown by comparison to Figure 2, which plots the numerical data provided in the two load forecast reports.

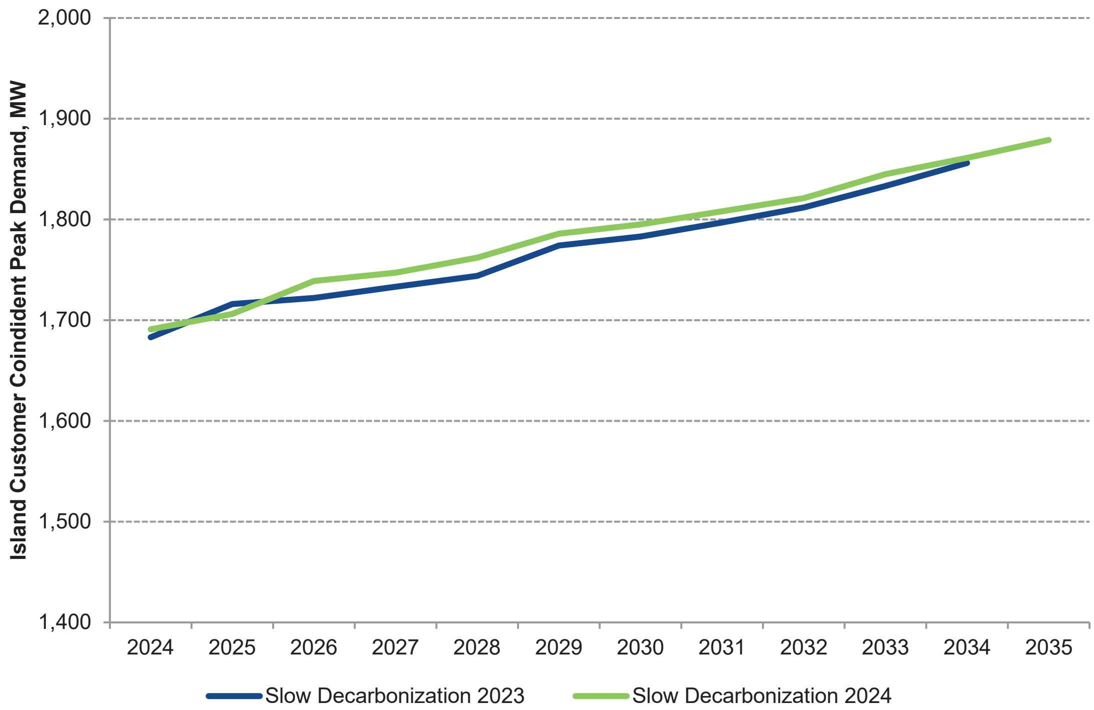
[44] Build Application, Schedule 3, Table 9.

Figure 1: Build Application comparison of 2023 and 2024 Load Forecasts[45]



[45] Build Application, Schedule 3, Appendix A, Chart 1.

Figure 2: Slow Decarbonization load forecast comparison from forecast report data tables[46]



(33) The numerical data, graphed in Figure 2, indicate that Slow Decarbonization scenario is slightly *higher* in the 2024 Load Forecast than the corresponding case from the 2023 Load Forecast. The data show that demand is approximately 5 MW higher in 2034 rather than 8 MW lower, as described in the Build Application. It is not clear which is correct, nor what data were actually incorporated in the expansion plan modeling supporting the Build Application.

(34) As discussed above, we find the more significant issue is that the load forecasting is uncertain, it changes year-to-year, and even relatively small changes produce significant changes in the expansion plan modeling. For this reason, we find that close monitoring of load trends is essential to determine what future path actually is more likely going forward.

C. Resource Planning Criteria

(35) In its Build Application, Hydro explains that it has maintained the same three resource planning criteria as used in the 2024 RAP.[47] The first is that the IIS should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.[48] Second, the IIS should

[46] Build Application, Schedule 3, Appendix A, Attachment 1, Table 4.

[47] Build Application, Schedule 3, page 1, lines 11 to 12.

[48] Build Application, Schedule 3, page 1, lines 11 to 15.

have sufficient generating capability to supply all its firm energy requirements with firm system capability.[49] Third, the IIS should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event.[50]

(36) Hydro explains that its Build Application also maintains the separation of the resource planning criteria for the IIS from the LIS by focusing only on the expansion of the IIS for the 2024-2034 period.[51] This is consistent with the RAP Settlement Agreement.[52]

i. Hydro was reasonable in selecting a 2.8 LOLH planning criterion due to the cost of a more stringent target, elevated in part by ongoing LIL performance issues

(37) We begin with Hydro's selection of a 2.8 LOLH reliability planning criterion. In November 2018, Hydro submitted its first filing in the RRA Study Review process.[53] In that filing, Hydro recommended a change from its long-standing target – a 0.2 Loss of Load Expectation[54] ("LOLE"),[55] or a standard of two outage days in ten years (which corresponds to a 2.8 LOLH) – to a more stringent target of 0.1 LOLE, or one outage day in ten years,[56] which would allow Hydro to voluntarily comply with North American Electric Reliability Corporation ("NERC") standards.[57] At that time, Hydro expected the LIL to be online in time for the 2018-2019 winter season[58] and modeled the LIL at its maximum rating (900 MW), with a bi-pole forced outage rate of 0.0114 percent (plus a 0.56 percent forced outage rate per pole).[59] Hydro did note that the "reliability of the LIL is a key driver of [Island Interconnected System] reliability."[60] During a monopole outage, the LIL is derated (to 675 MW under normal operation), but during a bipole outage, the capacity of the LIL is reduced to zero.[61]

[49] Build Application, Schedule 3, page 1, lines 16 to 17.

[50] Build Application, Schedule 3, page 2, lines 2 to 3.

[51] Build Application, Schedule 3, page 2 lines 4 to 6.

[52] RAP Settlement Agreement, Terms of Agreement item 1.

[53] Hydro, "Newfoundland and Labrador Hydro – the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Reliability and Resource Adequacy Study – November 2018," November 16, 2018 (*hereinafter* "2018 RRA Study").

[54] 2018 RRA Study, Volume 1, page 13 line 1.

[55] Loss of Load Expectation is the expected number of days each year where available generation capacity is insufficient to meet daily peak demand.

[56] 2018 RRA Study, Volume 1, page 14.

[57] 2018 RRA Study, Volume 1, page 14 lines 2 to 3.

[58] 2018 RRA Study, Volume 1, footnote 17.

[59] 2018 RRA Study, Volume 1, page 40 lines 16 to 17.

[60] 2018 RRA Study, Volume 1, page 40; 2018 RRA Study, Volume 1, Attachment 7, Table 5.

[61] Hydro, "2024 Resource Adequacy Plan Technical Conference #2 Issue #3: Existing Generation and Transmission," October 1, 2024, (*hereinafter* "2024 RAP Technical Conference #2 Issue #3") slide 47.

(38) Since the 2018 RRA Study, much has changed. The LIL has experienced "periods of unavailability due to structural and software issues"[62] and has still yet to achieve full commissioning to its full 900 MW rated capacity.[63] In 2022, Hydro acknowledged that "the previously-anticipated bipole forced outage rate of 0.0114% is no longer appropriate" for the LIL.[64] Hydro made a similar finding for the LIL's capacity.[65] Hydro stated that "[u]ntil the LIL is fully commissioned with multiple years of operational experience to better inform the selection of a bipole forced outage rate, the LIL capacity and bipole forced outage rate will be addressed with a range of upper and lower limits."[66] Since then, the LIL's bipole forced outage rate was 4% in 2023[67] and 3.37% in 2024,[68] based on a LIL capacity of 700 MW.[69] Hydro has also recently indicated that it has postponed the necessary testing of the LIL to reach its full rating of 900 MW until the Fall of 2025.[70]

(39) In its 2024 RAP, Hydro concluded that the more stringent resource adequacy planning criterion of 0.1 LOLE "remains cost-prohibitive at this time," noting the "balance between cost and reliability," and therefore "recommends maintaining the existing probabilistic criterion of LOLH [less than or equal to] 2.8."[71] Hydro has maintained that stance in the Build Application, proposing an LOLH standard of 2.8[72] and a corresponding planning reserve margin of 17.1%.[73]

(40) As we pointed out in our August 2024 report, Hydro is correct that there is a tradeoff between reliability and cost.[74] Hydro's decision to abandon, for now, the North American industry standard reliability target of 0.1 LOLE is an acknowledgment that its cost is too high, given the status of the LIL. Hydro estimated the incremental cost of meeting the more stringent standard (0.1 LOLE) at $2.3 billion in net present value terms, or about 56% more expensive than the selected 2.8 LOLH standard, and requiring an additional 135 MW of firm capacity.[75] This suggests the price of higher reliability (0.1 LOLE) is likely prohibitively high. And though Hydro has not conducted any model runs in

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[62] Hydro, "Reliability and Resource Adequacy Review – Reliability and Resource Adequacy Study – 2022 Update," October 3, 2022 (*hereinafter* "2022 RRA Update"), page 15 lines 22 to 23.

[63] 2022 RRA Update, page 16, lines 10 to 12.

[64] 2022 RRA Update, page 16 line 4.

[65] 2022 RRA Update, page 16 lines 10 to 12.

[66] 2022 RRA Update, page 16 lines 4 to 7.

[67] Hydro, "Reliability and Resource Adequacy Study Review – Labrador-Island Link Update for the Quarter Ended December 31, 2023," January 11, 2024 (*hereinafter* "Q4 2023 LIL Update"), page 3.

[68] Hydro, "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended December 31, 2024," January 31, 2025 (*hereinafter* "Q4 2024 Asset Performance Report"), page 18.

[69] Q4 2024 Asset Performance Report, page 7, Table 4 and footnote 15.

[70] Hydro, "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2025," April 30, 2025 (*hereinafter* "Q1 2025 Asset Performance Report"), page 1 footnote 2.

[71] 2024 RAP, Appendix B, page 7 lines 18 to 22.

[72] Build Application, Schedule 3, page 1 lines 13 to 15.

[73] Build Application, Schedule 3, Table 2.

[74] Bates White Assessment of 2024 RRA, page 5.

[75] Hydro, "2024 Resource Adequacy Plan Technical Conference #1: Load Forecast/Reliability Planning Criteria," September 17, 2024, (*hereinafter* "2024 RAP Technical Conference #1") slide 41.

support of its Build Application assuming a 0.1 LOLE resource adequacy planning criterion, the results of the 2024 RAP suggest Hydro acted reasonably in not doing so.

ii. Firm Energy criterion has a limited impact on Build Application

(41) Hydro proposes that the IIS should have sufficient generating capability to supply all its firm energy requirements with firm system capability.[76] This criterion has a limited impact on the Build Application. As Hydro points out, "[n]either BDE Unit 8 nor [the] Avalon CT provide firm energy to the system."[77] Hydro plans to meet its firm energy requirements through the addition of new wind, but as Hydro states, "[w]ind does not form part of the 2025 Build Application."[78]

(42) For purposes of review of the Build Application, we make two points. First, for capacity expansion modeling purposes, the new wind resources were "fixed," meaning specified as inputs and not otherwise "selected" by the model, to ensure that the firm energy requirements were met.[79] This is consistent with the approach in the 2024 RAP. There, Hydro ran two capacity expansion modeling runs that allowed the model to select new wind generation as a supply resource; the model did so, thereby identifying new wind as the lowest cost option for energy. However, the model did not select sufficient new resources to ensure that Hydro would meet its firm energy criteria.[80] To remedy this, Hydro "fixed" a wind profile of new wind resource additions that applied to all other capacity expansion model runs. This approach was retained for the Build Application.

(43) Second, wind resources contribute some firm capacity to the system, equal to 22% of its nameplate rated capacity.[81] Hydro's Minimum Investment Required Expansion Plan includes "up to" 400 MW of wind (added between 2030 and 2033).[82] This new wind would therefore contribute up to 88 MW of firm capacity. One update from the 2024 RAP has impacted Hydro's capacity expansion modeling. Specifically, Hydro explains that because the "energy requirements identified in the 2023 Load Forecast were less than the energy requirements identified in the 2024 Load Forecast, this led to a reduction of one 100 MW wind farm that is required in 2032."[83] Since Hydro's LIL Shortfall Analysis (covered next, below) selected 2032 as the model year, the analysis contains 22 MW fewer firm capacity contributions from wind. According to Hydro, this "compounds the shortfall amount

[76] Build Application, Schedule 3, page 1 lines 16 to 17.

[77] Build Application, Schedule 1, page 17 footnote 31.

[78] Build Application, Schedule 1, page 17 footnote 29.

[79] Build Application, Schedule 1, page 16, lines 5 to 9, footnote 25.

[80] Hydro, 2024 Resource Adequacy Plan Technical Conference #3: Scenarios and Sensitivities/Modelling Approach and Considerations, October 16, 2024, (*hereinafter* "2024 RAP Technical Conference #3") slides 82 to 84.

[81] Build Application, Schedule 1, page 17 footnote 30.

[82] Build Application, Schedule 1, page 17 lines 4 to 7.

[83] Build Application, Schedule 3, page 42 footnote 64.

that is represented in [the updated LIL Shortfall Analysis]" and "further strengthens the need for capacity on the Island Interconnected System."[84]

(44) We take no issue with Hydro's decision to plan its system to meet firm energy requirements, and we note that Hydro has not included any requests related to the new wind resources in its Build Application. However, as noted, the new wind resources do impact the overall capacity expansion model and LIL Shortfall Analysis, given that the new wind contributes firm capacity to Hydro's overall portfolio. Hydro has explained that it is "pursuing further studies in support of reliability and supply adequacy to maximize energy delivery to the Island over the LIL, potentially reducing [the Firm Energy] requirement [of 400 MW of wind]."[85] Nevertheless, Hydro states that any reductions to its targeted new wind resources "will not reduce the capacity requirements for the Island Interconnected System recommended in this [A]pplication."[86]

iii. LIL Shortfall Analysis is a necessary step that has a significant impact on Hydro's Build Application requests

(45) In its recent filings, Hydro has explained the importance of the performance of the LIL (as measured by its equivalent forced outage rate)[87] in determining the resource adequacy on the IIS. Hydro stated that "the LIL bipole [equivalent forced outage rate] has materially increased from 0.0114% to an assumed range of 1% to 10% and the LIL bipole outages become the primary driver of generation shortfall on the Island Interconnected System… "[88]

(46) Hydro also noted 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."[89] 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."[90] Hydro made it clear that an extended outage on the LIL would be a "high consequence event impacting the Island Interconnected System."[91]

(47) In other words, the LIL could negatively impact resource adequacy on the IIS in at least two ways: first, through an equivalent forced outage rate that far exceeds original expectation of about one

[84] Build Application, Schedule 3, page 42 footnote 64.

[85] Build Application, Schedule 1, page 12 lines 1 to 3.

[86] Build Application, Schedule 1, page 12 lines 6 to 7.

[87] Equivalent forced outage rate measures the percentage of time that the LIL system is unavailable at maximum rated capacity due to forced outages and derates. 2024 RAP Technical Conference #2 Issue #3, slide 47.

[88] 2024 RAP, Appendix B, page 4 line 23 to page 5 line 1.

[89] 2022 RRA Update, Volume III, page 27 line 23 to page 28 line 3.

[90] 2024 RAP, Appendix C, page 100 lines 9 to 11.

[91] 2024 RAP, Appendix B, footnote 11.

hundredth of a percent, and second, through an extended outage (six weeks). These are separate risks, and the relationship between them is not obvious. For example, the LIL may perform to a low equivalent forced outage rate but may still be at risk for an extended bipole outage.

(48) To account for these risks, Hydro took two steps. First, Hydro modeled a range of LIL equivalent forced outage rates, all of which were far higher than the original assumption of 0.0114%. These included 1%, 5%, and 10%.[92] Hydro has stated that the current remedial work Hydro is pursuing for the LIL will, at best, result in an expected LIL equivalent forced outage rate of 1%.[93] Second, Hydro conducted a "LIL Shortfall Assessment," which sought to ensure that "[t]he Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event."[94] The LIL Shortfall Assessment was "intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line" though could apply to "any prolonged outage event."[95] Hydro defined the "manageable level" of loss of load to "rotating outages [that] are reasonably within what has been experienced on the system before."[96] Hydro later defined this threshold to be a maximum of 100 MW of load shed, which Hydro states was the volume that "Newfoundland Power was able to rotate…during the 2014 loss of load event."[97]

(49) In its Build Application, Hydro has taken a similar approach. Hydro has assumed LIL equivalent forced outage rates of 1% and 5%, depending on the scenario modeled. (The Minimum Investment Required Expansion Plan Portfolio is based on the assumption of a more reliable LIL, with an equivalent forced outage rate of 1%.)[98] Hydro has also conducted a LIL Shortfall Analysis, which assumes a six-week outage during the "coldest period of the year (i.e., January and February)."[99]

(50) Our review of the Build Application and the 2024 RAP suggest that it is difficult to overstate the importance of the performance of the LIL in resource planning for the IIS. It is clear, for example, that the original expected equivalent forced outage rate of the LIL (0.0114%) is not a realistic assumption going forward, given the equivalent forced outage rates observed on the LIL to date. As the assumed LIL equivalent forced outage rate increases, the planning reserve margin needed to meet a 2.8 LOLH standard increases substantially: at a 1% equivalent forced outage rate, the planning reserve margin needed is 17.1%; at 5%, the planning reserve margin increases to 25.8%; at 10%, a 29.1% planning reserve margin is needed.[100] These higher planning reserve margins translate to

[92] 2024 RAP, Plan Overview, page 33 lines 15 to 20.
[93] 2024 RAP Technical Conference #1, slide 53.
[94] 2024 RAP, Appendix B, page 4 lines 2 to 3.
[95] 2024 RAP, Appendix B, page 9 lines 4 to 6.
[96] 2024 RAP, Appendix C, page 141 lines 7 to 8.
[97] Build Application, Schedule 3, page 40 footnote 63.
[98] Build Application, Schedule 3, page 16 lines 2 to 12.
[99] Build Application, Schedule 3, page 37 lines 10 to 11.
[100] 2024 RAP, Appendix C, Table 4.

higher firm capacity investment requirements and billions of dollars of additional costs. We address this issue later in our report.

(51) Even setting aside the equivalent forced outage rate of the LIL, the impact of a long-term outage on the LIL may be dire. Hydro has not assigned a probability of such an event, only noting that the risk is considerably higher than originally thought. Still, Hydro's effort to consider the planning implications for such an event is reasonable.

(52) We note that in the 2024 RAP, Hydro's consultant (Daymark Energy Advisors) suggested Hydro further study the LIL as its single largest contingency for the purposes of determining the amount of operating reserves it must hold at all times to maintain operational reliability.[101] We echoed this in our August 2024 Report, noting that "the single biggest loss the system may endure is a bipole outage (700-900 MW), not the loss of a single Muskrat Falls unit (206 MW)."[102] Hydro has addressed these comments, showing that planning for the LIL as an energy-only line would require an additional 315 MW of reserve requirement relative to the Minimum Investment Required Expansion Plan at an incremental cost of an additional $5.4 billion (NPV).[103] Alternatively, planning for the LIL as the system's single largest contingency would increase operational reserve requirements by 252 MW, which would require additional standby generation and reduce export opportunities.[104] These costs may violate the goal of a reasonable balance between reliability and cost.

(53) The LIL Shortfall Analysis remains a sensible and necessary assessment, primarily due to the unique resource adequacy profile of Hydro and its reliance on the LIL. Traditional probabilistic metrics of resource adequacy, including Hydro's selected probabilistic criteria of 2.8 LOLH, may not capture the full risk of the loss of an asset like the LIL for an extended period. Given the potential impact of such an extended outage, an additional, probabilistic assessment of an extended LIL outage is merited.

(54) Hydro has accurately noted that there are no specified planning criteria it can rely upon for conducting the LIL Shortfall Analysis.[105] Hydro also did not calculate specific values for the lost load that would be incurred during such an outage.[106] Instead, Hydro has attempted to determine the "maximum level of customer interruption that can be tolerated," which again is derived from the experience of the 2014 loss of load event, where Newfoundland Power was able to manage the outage

[101] 2024 RAP, Appendix A, pages 9 and 10

[102] Bates White Assessment of 2024 RRA, page 7.

[103] 2024 RAP Technical Conference #1, slide 49.

[104] 2024 RAP Technical Conference #1, slide 51. The current contingency plan, based on Muskrat Falls as the First Contingency, requires operational reserves of 309 MW. The 252 MW increase required when taking the LIL as First Contingency represents an 81.6% increase in operational reserve required.

[105] Build Application, Schedule 3, footnote 8.

[106] 2024 RAP Technical Conference #1, slide 56.

through rotation of 100 MW load sheds.[107] Hydro's approach is a reasonable overall proxy to determine the impact of a prolonged LIL outage and to assess the benefits of the proposed new resources (BDE Unit 8 and the Avalon CT) to mitigate that impact.

(55) We address Hydro's specific modeling approach to the LIL Shortfall Analysis later in Section III.H. We also later address the LIL Shortfall Analysis results and the substantial impact they have on the Build Application.

D. Existing Generation and Transmission

(56) A key consideration of the capacity expansion modeling efforts that underpin the Build Application is the treatment, modeling, and forecasted expectations regarding those assets that currently serve customer needs, including generation and transmission assets. In this section, we review Hydro's modeling and expectations of its existing assets.

(57) Generally, we do not take issue with much of Hydro's modeling or expectations of its existing generation and transmission assets. We reviewed Hydro's modeling in detail in the 2024 RAP proceeding and provided our assessment in August 2024;[108] as such, we will not repeat those details here.

i. Hydro has appropriately retained the modeled characteristics for its generating assets

(58) Hydro has retained the operating characteristics of the existing generating fleet in the modeling underpinning its Build Application.[109] Hydro made only a small change (-0.4 MW) to the nameplate capacity of the existing generation on the Exploits River (Grand Falls and Bishop's Falls) to 93.8 MW, with no change to the firm capacity of the generation (63 MW).[110] This small update has no impact on the modeling results. We observed no other concerns with Hydro's treatment of its existing generating assets.

ii. Thermal generating unit retirement dates are assumed and modeled for 2030, but may extend well beyond that as proposed, which may impose additional costs

[107] 2024 RAP Technical Conference #1, slide 55.
[108] Bates White Assessment of 2024 RRA, Section III.C.
[109] Information Provided to Bates White.
[110] Information Provided to Bates White.

(59) Hydro explains that "[n]o expansion generation units are required in the model prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets through the Bridging Period."[111] Hydro defines the Bridging Period as "the period from the present until 2030; the year in which aging thermal assets are assumed to be retired."[112] The "thermal assets" include Holyrood Thermal Generating Station ("Holyrood TGS"), Hardwoods Gas Turbine ("GT"), and Stephenville GT.[113] Hydro also notes that Newfoundland Power's Greenhill GT and Wesleyville GT are also to be retired in 2030.[114] Collectively, these resources total 618 MW of firm capacity, 590 MW of which is owned by Hydro.[115]

(60) Hydro has previously noted that there would "likely be some overlap between the Bridging Period and the Future Period (i.e., the period beyond 2030) while the existing thermal generation is retired and new generation is brought into service."[116] Hydro has stated that "[a]s new capacity is added and deemed reliable, existing thermal generation can be retired while closely monitoring system reliability in the interim to also ensure that Muskrat Falls Hydroelectric Generating Facility and the LIL are reliable before proceeding with on-Island retirements."[117] This sensible approach ensures a reliable transition during the commissioning and early operation of new assets and the retirement of existing assets.

(61) In the Build Application, Hydro identified the standards that must be met before the thermal retirements, including Holyrood TGS, can proceed. Hydro states: "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**."[118] That is, Hydro has identified three conditions that must be met before retirement of Holyrood TGS (and the GTs) can take place. Hydro did not further elaborate on these conditions in the Build Application.

(62) In discussions with Hydro, we gained additional clarity on these conditions. The first condition – "that sufficient alternative generation is commissioned" – is a reference to the commissioning of BDE Unit 8, the Avalon CT, or both. Until either new unit is commissioned and is proven to operate reliably, thermal retirements are unlikely, particularly at Holyrood TGS.[119] This is sensible, as it ties the retirement of existing firm capacity to the successful integration of new capacity. However, this

[111] Build Application, Schedule 1, page 16 lines 16 to 18.

[112] Build Application, Schedule 1, footnote 27.

[113] Build Application, Schedule 3, page 34 lines 1 to 2.

[114] 2024 RAP, Appendix B, Table 8. Hydro plans to transition certain assets at Holyrood and Hardwoods to synchronous condensers, which can provide grid services (e.g., voltage regulation) that help maintain grid stability.

[115] 2024 RAP, Appendix B, Table 8.

[116] NP-NLH-097(b), lines 15-17.

[117] NP-NLH-097(b), lines 18-21.

[118] Build Application, Schedule 3, page 13 footnote 23 (emphasis added).

[119] Information Provided to Bates White.

also introduces the risk that any delays in the construction and commissioning of BDE Unit 8, the Avalon CT, or both units, would necessarily delay retirement of the thermal assets. Such a scenario would involve ratepayers paying for both the costs of the new assets (BDE Unit 8 and the Avalon CT, once in service and deemed used and useful) and the capital, fixed operating and maintenance ("O&M"), variable O&M, and fuel costs of the thermal assets, including Holyrood TGS, beyond 2030.

(63) The second condition – that "adequate performance of the LIL is proven" – is a subjective standard that involves consideration of both the *level* and the *volatility* of the LIL equivalent forced outage rate.[120] Hydro did not provide a precise threshold but noted that multiple years of equivalent forced outage rates below 3% would potentially suffice.[121]

(64) The third condition – that "generation reserves are met" – refers to the resource planning criteria of 2.8 LOLH.[122] This is another sensible condition that ensures resource adequacy and is a more bright-line threshold that can be assessed through Hydro's existing reliability modeling. It should be noted, however, that reliability of the LIL will be a crucial determinant of whether this condition is met. If Hydro needs to plan for higher equivalent forced outage rates on the LIL, it will need to carry additional firm capacity to meet its 2.8 LOLH standard—which may delay retirement of the thermal assets.

(65) Each of these conditions has value insofar as they aim to ensure a reliable transition as Hydro's resource portfolio turns over. Each also carries risk. Any delays in the schedule for BDE Unit 8 and/or the Avalon CT could delay thermal retirements, as could elevated or otherwise volatile equivalent forced outage rates on the LIL. Delayed retirements could last as late as the end of 2034, at which point those units would no longer be in compliance with the *Clean Electricity Regulations*, or CER.[123]

(66) Should the retirement of the thermal units be delayed, there are likely to be significant costs for ratepayers. This is particularly true for the Holyrood TGS units. The table below shows that Hydro forecasts to spend an average of $138.4 million per year from 2030-2035, should the plant's retirement be delayed. In total, Hydro forecasts combined capital, operating, and fuel expenditures to be approximately $830.5 million over that period.[124] These costs would be additional to the costs associated with the BDE Unit 8 and Avalon CT at issue in this matter, assuming those resources reach commercial operations and are deemed used and useful.

[120] Information Provided to Bates White.
[121] Information Provided to Bates White.
[122] Information Provided to Bates White.
[123] 2024 RAP, Plan Overview, page 17 line 20.
[124] Information Provided to Bates White.

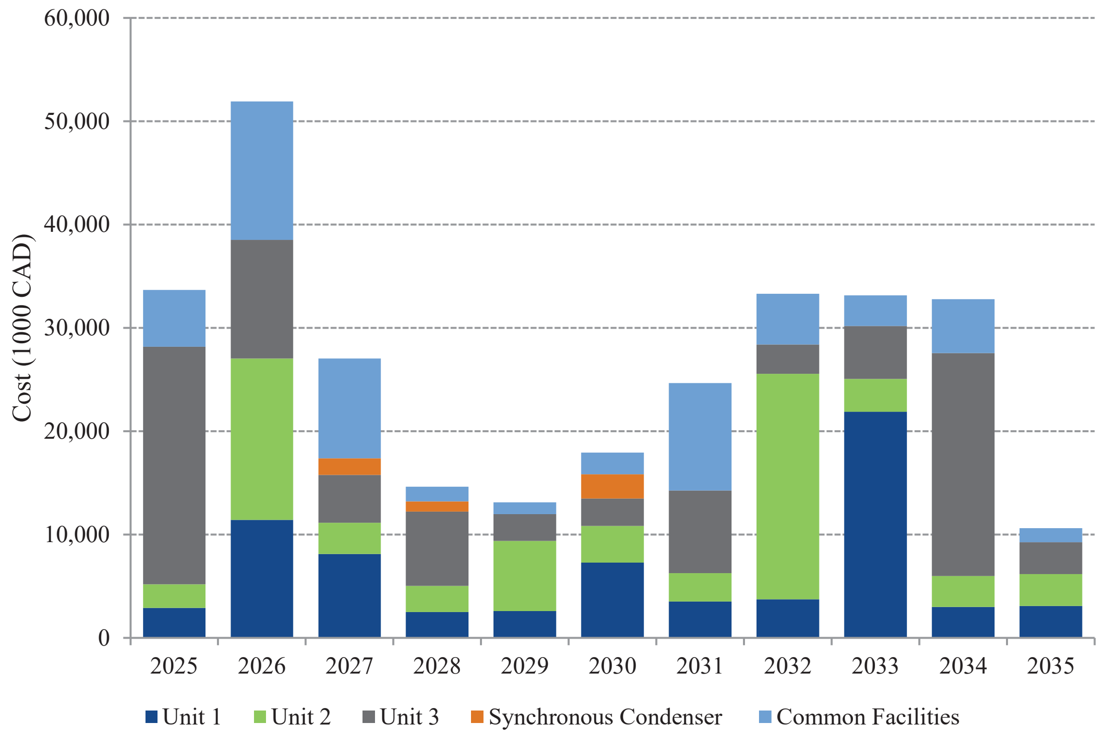
Table 1: Estimated Annual Cost of Operating Holyrood TGS (2030-2035) ($000) [125]

Cost Category	2030	2031	2032	2033	2034	2035	Total
Capital	17,934	24,650	33,305	33,138	32,776	10,617	152,421
Operating	29,952	30,851	31,776	32,730	33,711	34,723	193,743
Fuel	73,051	77,411	79,133	80,858	84,371	89,500	484,324
Total	120,937	132,912	144,214	146,726	150,858	134,840	830,488

(67) Hydro will also need to manage its capital investment in the Holyrood TGS facility as its planned retirement date nears. To avoid stranded investment at asset retirement, Hydro will seek to reduce capital expenditures at Holyrood TGS as the retirement date approaches. However, if retirement dates are delayed, additional capital expenditures may be needed to keep the units reliable. If retirement dates are uncertain, 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. The figure below demonstrates Hydro's current plan for capital investments, by unit, through 2035 should the retirement date be so delayed. Note that capital investment starts a decreasing trend in 2026 through the planned retirement year (2030), then ramps back up as the plant is sustained through 2034, before again falling in the final year into retirement (2035).

[125] Information Provided to Bates White.

Figure 3: Estimated Annual Capital Cost of Operating Holyrood TGS (2025-2035)[126]



(68) All this suggests a few key conclusions. First, any delay in new generating resources reaching commercial operations in a timely manner will have costs that must include the capital, operating, and fuel costs at Hydro's existing thermal generators. Second, and similarly, high and/or volatile equivalent forced outage rates on the LIL will also cause similar costs. Third, given the potential for delayed retirement dates, Hydro will need to develop a plan for managing its capital investments in its thermal generating assets as retirement dates approach.

iii. Modeled LIL Equivalent Forced Outage Rates are reasonable and demonstrate the impact of LIL performance on capacity needs and investment

(69) As noted earlier, in recent filings, Hydro has explained the importance of the performance of the LIL (as measured by its equivalent forced outage rate)[127] in determining the resource adequacy on the IIS. Hydro stated that "the LIL bipole [equivalent forced outage rate] has materially increased from 0.0114% to an assumed range of 1% to 10% and the LIL bipole outages become the primary driver of

[126] Information Provided to Bates White.

[127] Equivalent forced outage rate measures the percentage of time that the LIL system is unavailable at maximum rated capacity due to forced outages and derates. 2024 RAP Technical Conference #2 Issue #3, slide 47.

generation shortfall on the Island Interconnected System… "[128] Also as noted earlier, to account for the uncertainty of the LIL equivalent forced outage rate, Hydro modeled a range of LIL equivalent forced outage rates, all of which were far higher than the original assumption of 0.0114%. Hydro stated that "[u]ntil the LIL is fully commissioned with multiple years of operational experience to better inform the selection of a bipole forced outage rate, the LIL capacity and bipole forced outage rate will be addressed with a range of upper and lower limits."[129] These included 1%, 5%, and 10%.[130] In its Build Application, Hydro has taken a similar approach. Hydro has assumed LIL equivalent forced outage rates of 1% and 5%, depending on the scenario modeled. (The Minimum Investment Required Portfolio is based on the assumption of a more reliable LIL, with an equivalent forced outage rate of 1%.)[131]

(70) Hydro's approach to modeling a range of equivalent forced outage rates for the LIL is a reasonable way to plan for this uncertainty. The original expected equivalent forced outage rate of the LIL (0.0114%) is not a realistic assumption going forward, given the equivalent forced outage rates observed on the LIL to date. The LIL's bipole forced outage rate was 4% in 2023[132] and 3.37% in 2024,[133] based on a LIL capacity of 700 MW. While Hydro is pursuing remedial actions to improve LIL performance, Hydro has stated that the current remedial work Hydro is pursuing for the LIL will, at best, result in an expected LIL equivalent forced outage rate of 1%.[134]

(71) The impact of LIL performance is potentially large. In this Build Application, Hydro did not conduct any capacity expansion model runs that isolated the impact of a 1% equivalent forced outage rate versus a 5% rate. Scenario 1 model runs used both the Reference Case load forecast and 5% LIL forced outage rate, while Scenario 4 used the Slow Decarbonization load forecast and 1% LIL forced outage rate.[135] In the 2024 RAP, Hydro conducted model runs that did allow for such a comparison. To illustrate this, we selected Scenarios 6AEF, 2AEF, and 5AEF, as each use the same resource planning criteria (2.8 LOLH) and the same load forecast case (Accelerated Decarbonization). The only input that differs is the LIL equivalent forced outage rate.[136] As the assumed LIL equivalent forced outage rate increases, the planning reserve margin needed to meet a 2.8 LOLH standard increases substantially, as does the cost of doing so. This is shown in the table below.

[128] 2024 RAP, Appendix B, page 4 line 23 to page 5 line 1.
[129] 2022 RRA Update, Volume I, page 16 lines 4 to 7.
[130] 2024 RAP, Plan Overview, page 33 lines 15 to 20.
[131] Build Application, Schedule 3, page 16 lines 2 to 12.
[132] Q4 2023 LIL Update, page 3.
[133] Q4 2024 Asset Performance Report, page 18.
[134] 2024 RAP Technical Conference #1, slide 53.
[135] Build Application, Schedule 3, page 16 lines 2 to 12.
[136] 2024 RAP, Appendix C, Table 4 and Table 5.

Table 2: Impact of LIL Bipole Equivalent Forced Outage Rates on Planning Reserve Margin, Incremental Revenue Requirement (NPV $bn)[137]

Scenario	Capacity Planning Criteria (LOLH)	Load Forecast	LIL Bipole EqFOR (%)	Planning Reserve Margin (%)	Incremental NPV ($bn)
6AEF	2.8	Accelerated Decarbonization	1	17.1	$6.6
2AEF	2.8	Accelerated Decarbonization	5	25.8	$8.9
5AEF	2.8	Accelerated Decarbonization	10	29.1	$10.1

(72) The table illustrates the high cost of poor LIL performance. As the LIL equivalent forced outage rate increases from 1% to 5%, the impact on the NPV of Hydro's revenue requirement is a positive $2.3 billion. A 10% LIL forced outage rate increases that figure another $1.2 billion to $3.5 billion, an increase of 53%.

(73) In our August 2024 report, we identified third-party studies of the LIL's reliability (by Haldar & Associates, Inc.), explained some of the conclusions and recommendations of those studies, and noted Hydro's efforts to respond to those studies' recommendations to enhance the reliability of the LIL.[138] We explained that the efforts and investments Hydro pursues to enhance the reliability of the LIL "must demonstrate some benefit in light of their costs, and then must be weighed against alternatives (such as generation supply investments)."[139] We explained that "Hydro does not yet have the estimated cost of the LIL mitigation investments, nor the expected benefits" which "makes any comparison against the generation alternatives being recommended by Hydro…impossible."[140] We recommended that Hydro "continue to address all Haldar recommendations (and those in [Hydro's] own LIL incident reports) and update the RAP process with its findings to ensure the optimality of any resource adequacy and reliability investments made on behalf of customers."[141] Hydro, in response, indicated that "[a]ny ongoing remedial work would not reduce the requirements identified in the minimum investment required expansion plan"[142] and would, at best, maintain an equivalent forced outage rate of 1%.[143]

iv. Bay d'Espoir-Soldiers Pond transmission limit prevents BDE Unit 8's benefits from accruing to system and no specific solution proposed in Build Application

[137] 2024 RAP, Appendix C, Table 4, Chart 14.

[138] Bates White Assessment of 2024 RRA, pages 20 to 22.

[139] Bates White Assessment of 2024 RRA, pages 21 to 22.

[140] Bates White Assessment of 2024 RRA, page 22.

[141] Bates White Assessment of 2024 RRA, page 22.

[142] 2024 RAP Technical Conference #2 Issue #3, slide 51.

[143] 2024 RAP Technical Conference #1, slide 53.

(74) In May 2023, Hydro commissioned a study by TransGrid Solutions ("TransGrid") to determine the transmission constraints that would exist on the Bay d'Espoir to Soldiers Pond ("BDE-SOP") 230 kV transmission system in the event of a bipole outage on the LIL.[144] The study identified certain operational constraints on the Avalon Peninsula and found that following the transition from generation to synchronous condenser operations at Holyrood and the Hardwoods Gas Turbine, the BDE-SOP transmission system must supply the majority of the Avalon Peninsula's demand during a LIL bipole outage, assuming no new generation sources are constructed on the Avalon.[145] The study put forth several transmission-based solutions to address the On-Avalon transmission constraints identified in the study during a LIL bipole outage. The proposed solutions included line reconductoring, dynamic line ratings, and new transmission line builds (among others).[146]

(75) In the Build Application, Hydro explained that the existing BDE-SOP constraints "are defined based on 230 kV line contingencies that cause thermal overload on lines remaining in service and/or low voltage conditions that must be avoided to ensure reliable and safe operation."[147] Hydro further explained:

> Upon the retirement of the Holyrood TGS and Hardwoods GT on the Avalon, appreciable transmission bottlenecks are expected to occur during a LIL bipole outage, resulting in trapped Off-Avalon generation. From a transmission planning perspective, if more generation is added off the Avalon, increased transmission capacity along the Bay d'Espoir to Soldiers Pond corridor will be required to reduce the amount of load shedding required on the Avalon during a LIL bipole outage, once the Holyrood TGS and Hardwoods GT are retired.[148]

(76) Hydro noted that the "least-cost option [identified by TransGrid] to reliably meet Island demand in combination with the Expansion Plans applied during a LIL bipole outage to keep Avalon load shed requirements below 100 MW" is a third line from Western Avalon to Soldiers Pond, plus dynamic line ratings for TL201, TL202, TL206, and TL203 for a total cost of $150 million.[149] Hydro is not proposing to pursue this option, nor does the Build Application contain any proposal related to transmission investment or operational changes (such as dynamic line ratings) on the BDE-SOP corridor. Instead, Hydro explained that it is "exploring alternative steps to maximize transfer capacity through existing assets, including the implementation of a [remedial action scheme] and/or [dynamic line rating] technology," which, "if proven, are technically equivalent to the [$150 million]

[144] Hydro, "Avalon Supply (Transmission) Study," October 31, 2023 (*hereinafter* "Avalon Transmission Study"), Overview, page 2 lines 2 to 5.

[145] Avalon Transmission Study, page 2 lines 10 to 13.

[146] Avalon Transmission Study, page 5 line 12 to page 6 line 10.

[147] Build Application, Schedule 3, page 49 lines 2 to 4.

[148] Build Application, Schedule 3, page 49 line 12 to page 50 line 2.

[149] Build Application, Schedule 3, page 50 lines 4 to 8.

transmission upgrades" identified by TransGrid.[150] Hydro explains that it is actively assessing dynamic line rating technologies for use on thermally-constrained lines and has retained TransGrid to study whether a remedial action scheme is a technically viable solution to increase the transfer limits on the BDE-SOP corridor, with a report from TransGrid expected "by the end of the second quarter of 2025."[151]

(77) We explored this issue in additional detail with Hydro. Hydro explained that, if all single contingency events were ignored, the limit for eastward flow across BDE-SOP would be 980 MW.[152] This would be sufficient transfer capacity to deliver 100% of Bay d'Espoir's maximum generation (763 MW) – including that from BDE Unit 8 – east to the Avalon. However, in considering single contingencies with the LIL in service, the maximum eastward flow on BDE-SOP is 680 MW under normal operating conditions.[153] This limit is further reduced to 603 MW during a LIL bipole outage.[154]

(78) The implication of this data is that the current, unmitigated BDE-SOP constraint prevents Hydro from delivering all of the incremental potential output of BDE Unit 8 during normal conditions and prevents delivery of *any* of the incremental output of BDE Unit 8 during a LIL bipole outage. This is shown in the figure below, which shows the capacity of Bay d'Espoir, broken out by units 1-7 (613 MW) and unit 8 (150 MW). The orange horizontal line at the top of the figure is the 980 MW transfer capacity of the BDE-SOP, ignoring any single contingency constraints. The blue horizontal line shows the 680 MW BDE-SOP transfer limit under normal operations with the LIL in service; this allows for delivery of up to 67 MW of incremental BDE Unit 8 output, but no more. The red horizontal line represents the transfer limit (603 MW) during a bipole outage; at this level, zero incremental output from BDE Unit 8 can be delivered.

150 Build Application, Schedule 3, page 50 lines 9 to 11. A remedial action scheme allows for instantaneous load shed following a contingency event to avoid a transmission line overload and/or abnormal voltage conditions. Dynamic line ratings would allow for operation of transmission lines at higher ratings when conditions allow.

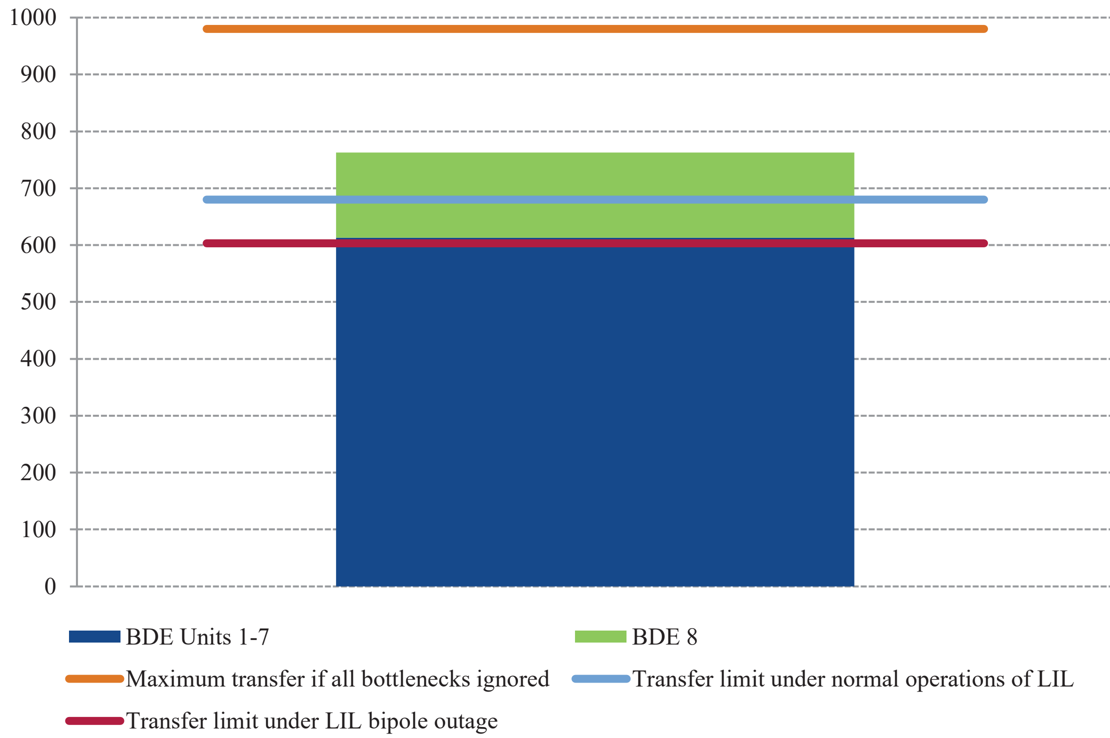
151 Build Application, Schedule 3, page 50 lines 19 to 25.

152 Information Provided to Bates White.

153 Information Provided to Bates White.

154 Information Provided to Bates White.

Figure 4: Bay d'Espoir capacity vs. BDE-SOP eastward transfer limits[155]



(79) The implication of these data is that as constituted, the BDE-SOP 230 kV system prevents transmission of *any* incremental output from BDE Unit 8 during a LIL bipole outage, exactly when that output is needed most. Even during normal operations with the LIL in service, just a fraction (67 out of 150 MW) of the incremental output from BDE Unit 8 is deliverable.

(80) Hydro has made it clear that it is exploring transmission solutions that will not only alleviate this constraint but will also restore a maximum transfer capability over BDE-SOP of 980 MW.[156] It must be noted, however, that the Build Application leaves unanswered the question of how this constraint will ultimately be alleviated, and at what cost. The TransGrid study was completed in October 2023, and while we agree with Hydro's efforts to pursue transmission solutions that are alternatives to the $150 million "least cost" transmission upgrade solution, the unresolved nature of this issue reduces confidence in BDE Unit 8 as a generation resource. As it stands, the Board has been asked to approve the development of BDE Unit 8 at a cost of $1.08 billion, but with no clear explanation of how the transmission grid will be upgraded or managed to allow for the reliability benefits of BDE Unit 8 to accrue to the system. The TransGrid study (due by the end of the second quarter of 2025) and the results of Hydro's dynamic line rating technology review will likely be instructive and may be

[155] Information Provided to Bates White.
[156] Information Provided to Bates White.

necessary to adequately assess the BDE Unit 8 resource in this matter. Hydro should endeavor to provide these updates as soon as possible, including any adjustments to the NPV of expansion plan scenarios inclusive of BDE 8.

E. Supply Resource Options

(81) The resource options evaluated for the Build Application were established based on studies and modeling performed in the development of the 2024 RAP, which represented an update to the 2023 Reliability and Resource Adequacy Study ("2023 RRA"). As summarized in the 2024 RAP Report, Hydro considered a range of supply and demand side options to meeting system needs over a ten-year planning horizon.[157] The resulting set of resources identified as potential future alternatives were the following:

- Demand-side measures (incorporated within the load forecasts applied in modeling of supply resource options)
- Hydroelectric generation:
  - Additional units at existing facilities
    - Bay d'Espoir Unit 8
    - Cat Arm Unit 3
  - New facilities
    - Island Pond
    - Round Pond
    - Portland Creek
  - Incremental capacity/efficiency potential from existing units
- Thermal generation:
  - Simple Cycle Combustion Turbines (SCCTs)
- Wind generation
- Battery energy storage systems (BESS)
- Solar
- Market purchases

Table 3 shows the reported capital costs for incremental supply resources applied in the development of the 2024 RAP, with the dollar values shown in $/kW of firm capacity. As the Build Application is focused on meeting capacity needs (and not energy), the focus of this discussion of evaluated resources is on firm capacity and its associated cost.

[157] Bates White Review of 2024 RRA, Section III.E.

Table 3: Expansion Supply Resources, 2024 RAP, $ per kW of Firm Capacity ($2023)[158]

Resource Type	Resource	Firm Capacity, MW	Cost, 2024 RAP
Hydro	Bay D'Espoir Unit 8	154.4	$3,345
	CAT - Unit 3	68.2	$4,662
	Island Pond	36	$15,570
	Portland Creek	23	$15,746
	Round Pond	18	$19,055
Thermal	Avalon CT	141.6	$3,205
Wind	100 MW installed	22	$9,464
Battery	50 MW installed	30	$3,701
Solar	20 MW installed	0	NA[159]
Proxy Capacity	50 MW	50	$10,000

(82) Though wind additions are not included in the Build Application, expansion modeling for the RAP and the Build Application identified wind as the most economic resource to meet growth in firm energy needs. In both modeling exercises, Hydro evaluated needed capacity additions while maintaining a fixed wind profile to ensure forecasted energy needs were met.[160] The added wind generation also affects net capacity needs, because wind is assigned a firm capacity value based on an ELCC of 22% of installed capacity.[161]

(83) The results of both the RAP and Build Application evaluations can largely be intuited from the relative capital costs in Table 3. Specifically, the expansion model selects BDE Unit 8 and the Avalon CT to meet the projected need for firm capacity because they have the lowest capital costs of the incremental supply resources that could meet the need.

(84) For modeling purposes, Holyrood TGS, Hardwoods GT, and Stephenville GT are assumed to be retired by 2031,[162] creating a capacity need in that year of 150 MW under the Slow Decarbonization load forecast.[163] Though the modeled capital cost of the Avalon CT is slightly lower than that for BDE Unit 8,[164] the PLEXOS model considers the annualized costs of the respective resources, which are lower for BDE Unit 8 because cost is assumed to be amortized over a significantly longer asset life – 60 years for BDE Unit 8 compared to 35 years for the Avalon CT.[165] BDE Unit 8 is thus

[158] 2024 RAP, Appendix C, Table 1.

[159] Solar does not provide firm capacity; the estimated capital cost in the 2024 RAP was reported as $1,659 per kW of installed capacity.

[160] Build Application, Schedule 1, page 16 lines 5 to 9; 2024 RAP, Scenario Summary Tables.

[161] 2024 RAP, Appendix B, page 29 lines 1 to 2.

[162] 2024 RAP, Appendix C, page 82 lines 20 to 23; Build Application Schedule 3, Chart 6.

[163] 2024 RAP, Appendix C, page 83 lines 1 to 3.

[164] Build Application, Schedule 4, Appendix A, Table 1; Build Application, Schedule 5, Appendix B, Table 1.

[165] Build Application, Schedule 1, page 53, lines 14 to 16.

selected by PLEXOS to enter service first (in 2031). Further load growth beyond 2031 results in an additional capacity need in 2035, and PLEXOS selects the Avalon CT for that year. As discussed further below, the RAP analyses included BESS resources and indicated potential value for some quantity of batteries as an alternative in some model cases. The evaluation of alternatives performed for the Build Application excluded BESS resources.

(85) The BDE Unit 8 and Avalon CT costs assumed for the RAP analyses reflected Class 5 cost estimates, as defined by the AACE, and which Hydro describes as "based on conceptual documentation" with an accuracy of minus 50% to plus 100% of estimated cost.[166] For the Build Application, Hydro developed Class 3 cost estimates, with an expected accuracy range of -20% to +30% around the estimated P50 cost value.[167] In response to an information request, Hydro provided the resource capital costs applied in the evaluations supporting the Build Application.[168] However the $/kW values provided were not directly comparable to those reported for the RAP analyses shown in Table 3, as the hydroelectric and thermal resource costs for the Build Application incorporated interest during construction and escalation, while the values reported for the RAP did not.

(86) Table 4 compares the capital cost estimates for BDE Unit 8 and the Avalon CT between the RAP analyses and those supporting the Build Application, in millions of dollars. The values for the Build Application are the reported capital cost values, including contingency, from the respective "basis of estimate" documents from the Build Application filing.[169]

Table 4: BDE Unit 8 and Avalon CT Capital Cost, Including Contingency, Excluding IDC, $millions[170]

Unit	RAP (Class 5) millions of 2023$	Application (Class 3) millions of 2024$	% Difference
BDE Unit 8	$516.5	[redacted]	[redacted]
Avalon CT	$453.8	[redacted]	[redacted]

(87) Hydro notes "[t]he increase [from Class 5 to Class 3] is driven by a number of factors including supply chain pressures on pricing for major equipment, refinement of indirect cost estimates, increased financing costs and the addition of Management Reserves.[171] In any case, based on the Class 3 cost estimates for BDE Unit 8, Hydro also applied increases to the cost estimates for the other

[166] 2024 RAP, Appendix C, footnote 26.

[167] Build Application, Schedule 5, Attachment 1, CT Basis of Estimate, page 1.

[168] Information Provided to Bates White.

[169] Build Application, Schedule 4, Appendix A, Table 1; Build Application, Schedule 5, Appendix B, Table 1.

[170] Values for the 2024 RAP are derived from reported $/kW costs assuming that these include contingency. Values for the Build Application are from the respect resource evidence documents Information Provided to Bates White; Build Application, Schedule 4, Appendix A, Table 1; Build Application, Schedule 5, Appendix B, Table 1.

[171] Build Application, Schedule 1, page 29 lines 26 to 28. *See also*: Schedule 1, Attachment 1, Table 2-4.

generation alternatives, and the relative cost advantages of BDE Unit 8 and the Avalon CT in the Build Application evaluations remained similar to those in the RAP modeling.[172]

(88) Hydro also performed expansion model scenarios with cost sensitivities for hydroelectric resources (including BDE Unit 8) and the Avalon CT. Unlike the RAP, where cost sensitivities examined the effects of hydroelectric and/or CT costs being 50% greater than estimated,[173] the Build Application cost sensitivities were derived from Monte Carlo estimations that simulated a distribution of costs for a large number of probabilistic variables.[174] Hydro selected "P85" cost levels from the Monte Carlo simulations, meaning the 85th percentiles for the cost distributions of hydro resources and the Avalon CT.[175] The base resource costs (including financing) and the P85 levels are shown in Table 5, in 2024 $/kW, with a calculation of the percent difference of P85 to base. Table 5 also includes cost cases Hydro considered that apply a potential federal Clean Electricity Investment Tax Credit ("ITC") to hydro resources.

Table 5: Build Application Capital Costs and Sensitivities, 2024$/kW, Including Financing[176]

Resource Type	Resource	Firm Capacity, MW	Cost	P85 Cost	P85 to Base % difference	Cost with ITC	ITC to Base % difference
Hydro	Bay D'Espoir Unit 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	CAT - Unit 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Island Pond	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Portland Creek	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Round Pond	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Thermal	Avalon CT	[redacted]	[redacted]	[redacted]	[redacted]		

i. Management Reserve and P85 Costs

(89) The Monte Carlo analyses for BDE Unit 8 and the Avalon CT costs were used to determine both an additional contingency adder and the Management Reserve.[177] For BDE Unit 8, the base cost estimate already includes both a Design Development Allowance ("DDA") and a Contingency Allowance, totaling [redacted] million.[178] DDA is described as "based on the level of design maturity to account for

[172] Build Application, Schedule 1, page 12 lines 16 to 18.

[173] 2024 RAP, Appendix C, Table 19 and Table 32; 2024 RAP Scenario Summary Tables.

[174] Information Provided to Bates White; Build Application, Schedule 4, Attachment 1, Table 1; Build Application, Schedule 5, Attachment 1, Table 1. High Capital Costs are reflected via the "Management Reserve" line item, which elevates the cost estimate from a P50 to a P85 using the Monte Carlo Simulation results.

[175] Build Application, Schedule 4, page 43, lines 5 to 11.

[176] Information Provided to Bates White.

[177] Build Application, Schedule 4, Attachment 1, pages 1, 22, 23, and 24.

[178] Build Application, Schedule 4, Attachment 1, page 22.

anticipated foreseeable and controllable growth in a particular work item as engineering advances."[179] The Contingency Allowance is described as addressing "the impact of foreseeable but uncontrollable events related to a work scope."[180] The Monte Carlo analysis for BDE Unit 8 was then used to derive an additional contingency amount, corresponding to the difference between the simulated P50 value (which for BDE Unit 8 also corresponds to the average or mean value for the resulting distribution) and the base estimate, which amounts to [redacted] million.[181]

(90) Management Reserve for BDE Unit 8 was determined in two components. The first is the Management Reserve on base costs, equal to the difference between the P85 level of the Monte Carlo distribution of total costs (the P85 value itself calculated as the average of P80 and P90 values).[182] This component is estimated at [redacted] million.[183] The second component is Management Reserve on strategic risks, which is based on a separate Monte Carlo of strategic risk factors, with the corresponding Management Reserve component being equal to the full P85 value (again, taken as the average of P80 and P90 values).[184] The strategic risks component is entirely additive – i.e., it is not the difference between the P85 value and a P50 value assumed to be reflected in the base cost. This second Management Reserve component is estimated at [redacted] million, and the combined Management Reserve for BDE Unit 8 equals [redacted] million.[185] The cost components for BDE Unit 8 that produce the Authorized Budget request are summarized in Table 6, below.

(91) The procedure applied with respect to the Avalon CT differs in several significant ways from that for BDE Unit 8. One basic difference is that rather than the P50 value of the base cost Monte Carlo distribution, the P55 value was applied in determining the Contingency and Management Reserve amounts. The reason for this is that for the Avalon CT cost distribution, the P55 value corresponded closely to the mean, which was considered the more appropriate reference for estimating Contingency and Management Reserve amounts.[186] For the Avalon CT, therefore, Contingency equals the difference between the P55 value and the base cost estimate. A more distinct difference in methodology from that for BDE Unit 8 is that the Management Reserve for the Avalon CT has only one component, and simply equals the difference between the P85 value and the P55 value of the base cost Monte Carlo distribution.[187] There is no separate, additional Management Reserve component for

[179] Build Application, Schedule 4, Attachment 1, page 21.
[180] Build Application, Schedule 4, Attachment 1, page 21.
[181] Build Application, Schedule 4, Attachment 1, page 22.
[182] Build Application, Schedule 4, Attachment 1, page 23.
[183] Build Application, Schedule 4, Attachment 1, page 24.
[184] Build Application, Schedule 4, Attachment 1, page 23.
[185] Build Application, Schedule 4, Attachment 1, page 24.
[186] Information Provided to Bates White.
[187] Build Application, Schedule 5, Attachment 1, pages 1 and 20.

strategic risks, as applies for BDE Unit 8.[188] Table 6 summarizes the cost components for BDE Unit 8 and the Avalon CT.

Table 6: BDE Unit 8 and Avalon CT Cost Buildup, 2024$ millions

	BDE Unit 8	Avalon CT
Base Cost Estimate[189,190]	[redacted]	[redacted]
+ Contingency	[redacted]	[redacted]
Base + contingency[191,192]	[redacted]	[redacted]
+ Escalation and financing[193,194]	[redacted]	[redacted]
Planned Budget	[redacted]	[redacted]
+ Management Reserve[195,196]	[redacted]	[redacted]
Authorized Budget[197,198]	**$1,079.2**	**$891.4**

(92) The respective Monte Carlo simulations for BDE Unit 8 and the Avalon CT were performed by different contractors with different proprietary tools.[199] Another significant distinction between the two methods involves the treatment of contingency components of cost. As described above, the base cost estimate for BDE Unit 8 incorporated both Design Development and Contingency Allowances. The Monte Carlo-derived Contingency amount is additive to those, and the combined total is [redacted] million, amounting to [redacted] of the base excluding DDA and Contingency allowances.[200]

(93) The Front-End Engineering Design ("FEED") Study for the Avalon CT analysis presents a reconciliation between the Class 3 cost estimate and the prior Class 5 estimate for the resource.[201] This comparison clarifies that the Class 5 estimate reflected [redacted] million in contingency compared with the [redacted] million derived from the Monte Carlo analysis, thus representing an [redacted] million reduction

[188] Build Application, Schedule 5, Attachment 1, page 20.
[189] Build Application, Schedule 4, Attachment 1, page 1.
[190] Build Application, Schedule 5, Attachment 1, page 1.
[191] Build Application, Schedule 4, Attachment 1, page 22.
[192] Build Application, Schedule 5, Attachment 1, page 20.
[193] Build Application, Schedule 4, Attachment 1, pages 19 and 22.
[194] Build Application, Schedule 5, Attachment 1, pages 16 and 17.
[195] Build Application, Schedule 4, Attachment 1, pages 23 and 24.
[196] Build Application, Schedule 5, Attachment 1, page 20.
[197] Build Application, Schedule 4, Attachment 1, page 2.
[198] Build Application, Schedule 5, Attachment 1, page 2.
[199] Information Provided to Bates White.
[200] Build Application, Schedule 4, Attachment 1, pages 22 and 24. Total Base Cost minus DDA and Contingency Allowance is equal to: [redacted] - [redacted] = [redacted].
[201] Build Application, Schedule 5, Attachment 2, Table 2-4.

from Class 5 to Class 3 estimates (while direct and indirect project costs increased by [redacted] million). Thus, in contrast to BDE Unit 8, the Avalon CT base cost estimate shown in Table 6 excludes distinct uncertainty allowances, and the full Project Contingency amount of [redacted] million is determined by the Monte Carlo simulation, amounting to [redacted] of the base estimate.[202]

(94) The differences between the BDE Unit 8 and Avalon CT assessments in the treatment of cost allowances and the application of Monte Carlo simulation represent a methodological inconsistency. In our view, treating discrete cost risks and Monte Carlo-based cost risks additively, as was done for BDE Unit 8, is not an appropriate approach. At the same time, this inconsistency does not necessarily inject significant error that would affect the expansion plan results. Despite the inconsistent methods, the total cost risk allowances for BDE Unit 8 and the Avalon CT are roughly comparable as a percent of base cost estimates. Table 7 presents the various cost risk components for the two projects in more detail and excludes the escalation and financing components. The AACE's cost estimation guidelines consider Class 5 and Class 3 cost estimates to include appropriate contingency.[203] Table 7 calculates a "Class 3" capital cost estimate on this basis (i.e., base cost plus allowance/contingency), and then shows that the additional Management Reserve represents approximately [redacted] on top of the respective estimates for both BDE Unit 8 and the Avalon CT. This is within the notional high end accuracy expectation of +26% referenced by Hydro.[204]

Table 7: Cost Risk Components of BDE Unit 8 and ACT Estimates, 2024$ millions

		BDE Unit 8[205]	Avalon CT[206]
Base Cost Estimate (BDE Unit 8 Base Cost is the Base Cost as given, less DDA and Contingency Allowance)	(a)	[redacted]	[redacted]
DDA and Contingency Allowance	(b)	[redacted]	
Monte Carlo P50/P55 Contingency	(c)	[redacted]	[redacted]
Total allowance/contingency	(d) = (b)+(c)	[redacted]	[redacted]
"Class 3": base plus allowance/contingency	(e) = (a)+(d)	[redacted]	[redacted]
Management Reserve	(f)	[redacted]	[redacted]
% of base plus allowance/contingency	(g) = (f)/(e)	[redacted]	[redacted]

(95) We note that the Monte Carlo determinations of both Contingency and Management Reserve are relative to project cost estimation *excluding* escalation and financing,[207] but in the respective basis of

[202] Build Application, Schedule 5, Attachment 1, Section 11.0 through 13.0.

[203] AACE, "Recommended Practice No. 18R-97, Cost Estimate Classification System – As Applied In Engineering, Procurement, And Construction For The Process Industries," February 2, 2005, pages 3 to 4, available at: https://aheinc.ca/wp-content/uploads/2018/12/AACE-Cost-Estimate-Classification-System.pdf.

[204] Build Application, Schedule 5, page 25, lines 5 to 6.

[205] Build Application, Schedule 4, Attachment 1, pages 22 and 24. Total Base Cost minus DDA and Contingency Allowance is equal to: [redacted] - [redacted] = [redacted].

[206] Build Application, Schedule 5, Attachment 1, page 2.

[207] Build Application, Schedule 4, Attachment 1, page 15; Build Application, Schedule 5, Attachment 1, page 1.

estimate documents, Management Reserve is shown as a component after escalation and financing – a presentation that repeated in Table 6, above.[208] The Management Reserve appears to capture the potential for higher base costs, but to exclude escalation and financing, both of which would presumably be part of requested cost recovery. Consequently, we conclude that the requested Authorized Budget in the Build Application is likely too low. Table 8 incorporates a recalculation of the Management Reserve to include escalation and financing, in the same proportion as reflected in the Planned Budget relative to the base cost plus the Monte Carlo-derived Contingency. An adjusted Authorized Budget is then calculated, showing increases relative to the filed amounts of [redacted] million for BDE Unit 8 and [redacted] million for the Avalon CT.

Table 8: Recalculation of Authorized Budget for Management Reserve Including Escalation and Financing, 2024$ thousands[209]

		BDE Unit 8	Avalon CT
Base Cost	**(a)**	[redacted]	[redacted]
Monte Carlo P50/P55 Contingency	(b)	[redacted]	[redacted]
Base Cost plus Contingency	**(c) = (a)+(b)**	[redacted]	[redacted]
Escalation and financing	(d)	[redacted]	[redacted]
Planned Budget	**(e) = (c)+(d)**	[redacted]	[redacted]
Management Reserve (MC excl. esc., fin.)	(f)	[redacted]	[redacted]
Management Reserve incl. esc., fin.	(g) = (f)x(e)/(c)	[redacted]	[redacted]
Authorized Budget (adjusted)	**(h) = (e)+(g)**	**$1,116.2**	**$913.3**
Authorized Budget (filed)	**(i)**	**$1,079.2**	**$891.4**
Difference	(j) = (h)-(i)	$37.0	$21.9

(96) Though these adjustments are not large – on the order of 3% of the original filed Authorized Budget amounts – we note that there is a differential impact between BDE Unit 8 and the Avalon CT, because interest during construction represents a higher percentage of costs for BDE Unit 8, reflecting its longer construction period relative to the Avalon CT.[210]

(97) Of greater significance is the fact that the same issue appears in the expansion plan cases incorporating the P85 cost estimates for BDE Unit 8 and the Avalon CT. The annualized capital cost values incorporated in the expansion plan modeling for the P85 cases (corrected for an escalation error, as discussed below) reflect the same ratio to base cost as the filed Authorized Budget relative to the Planned Budget. This indicates that the same issue of concern is present in the expansion plan modeling – i.e., the P85 cases (corresponding to the Authorized Budget) do not include escalation and

[208] *See, for example:* Build Application, Schedule 4, Appendix A, Table 1, *or*, Build Application, Schedule 5, Appendix B, Table 1.

[209] Build Application, Schedule 4 Attachment 1, Table 1; Build Application, Schedule 5 Attachment 1 Table 1.

[210] Build Application, page 5.

interest during construction for the Management Reserve amounts. We believe this likely warrants re-running the expansion plan cases for the P85 cases, particularly considering the differential impact on BDE Unit 8 and the Avalon CT, noted above.

ii. Corrected Annualized Build Costs

(98) Another issue of greater dollar magnitude is that, in response to a clarification question from Bates White, Hydro confirmed that escalation of the capital costs for BDE Unit 8 and the Avalon CT for incorporation in the expansion plan modeling was applied incorrectly. Hydro provided corrected values for the annualized capital costs and, subsequently, revised cost data for the various expansion plan cases.[211] The original and corrected annualized capital costs, and associated impacts on resource cost NPVs are summarized in Table 9.

Table 9: Capital Cost escalation correction and NPV impacts, 2031 in-service date, 2024$ millions[212]

	Original		Corrected		Change	
	BDE Unit 8	ACT	BDE Unit 8	ACT	BDE Unit 8	ACT
Base Annual Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NPV	$788.1	$738.3	$673.8	$647.4	-$114.3	-$90.9
P85 Annual Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NPV	$910.7	$862.3	$778.6	$756.1	-$132.1	-$106.2

(99) Hydro provided revised cost results for all the expansion plan scenarios evaluated, showing corresponding reductions in NPV results. There was no impact on the resource selections in the scenarios. This correction has no effect on the Planned Budget or Authorized Budget amounts, though a correction to the Management Reserve calculation discussed above would affect the Authorized Budget.

iii. Treatment of CT Fuel Burn-off costs

(100) In addition to the difference in build cost, BDE Unit 8 and the Avalon CT have different modeled costs for fixed operations and maintenance (“FOM”), variable operations and maintenance (“VOM”) and fuel costs. While neither resource is expected to provide any net energy to the system under normal circumstances, Hydro’s modeling of the Avalon CT assumes that ten days of stored fuel would need to be burned off annually, even though it is not economic to do so for the purposes of serving electrical needs of the system. The burn-off requirement results from the fact that stored fuel degrades over time and would need to be removed and replenished periodically – the most expedient way being to use the fuel in generating power. Hydro characterizes the modeled fuel burn-off

[211] Information Provided to Bates White.

[212] Information Provided to Bates White.

requirement as a "worst-case scenario," while noting that "[f]urther study is ongoing to assess extending the shelf life of the fuel in storage, and/or determining if there is a way to cycle unused fuel via new contractual agreements or partnerships means."[213]

(101) Figure 5 shows the modeled costs of BDE Unit 8 and the Avalon CT in NPV terms, where each enters service in 2031. This corresponds to the Reference Case, sensitivity 1AEF.[214] VOM costs represent very small amounts, and are not visible in the chart. In NPV terms, the build cost of BDE Unit 8 is approximately $29 million greater than that of the Avalon CT.[215] FOM costs are similar for the two facilities, with FOM for the Avalon CT being approximately $5.8 million greater in NPV.[216] It can be seen from the figure below that the assumed fuel burn-off represents a very significant cost. Without this assumed cost, BDE Unit 8 would be $23.1 million more costly than the Avalon CT in NPV terms. Including the burn-off cost results in a $168.2 million NPV cost advantage for BDE Unit 8.

Figure 5: Modeled costs of BDE Unit 8 and the Avalon CT, 2031 in-service date, NPV 2024$ millions[217]

[redacted]

[213] Build Application, Schedule 3, page 20.
[214] Build Application, Schedule 3, Table 4.
[215] Information Provided to Bates White.
[216] Information Provided to Bates White.
[217] Information Provided to Bates White.

(102) Given the significance of the fuel burn-off issue, the results of Hydro's study of cost-mitigating alternatives will be particularly important. We also note that Hydro's expansion modeling assigns more than 60% of the NPV cost for the Avalon CT fuel burn-off to the period 2040 and beyond. This effectively assumes that no solution to the fuel burn-off inefficiency is ever developed. This appears to be an extreme assumption, and one that has a significant effect on resource assessment. An illustration of this is shown in Figure 6, which distinguishes between the fuel burn-off effect for 2031-2039 and that for the 2040 and later period. The figure also incorporates the Management Reserve component for BDE Unit 8 for reference. Finally, we note that Hydro's NPV methodology, which effectively accounts for annual costs extending in perpetuity, means that the effect of the fuel burn-off cost is extended well beyond the 35-year asset life of the Avalon CT.[218] This further exaggerates the fuel burn-off penalty, amounting to approximately 16% of the incorporated cost.

Figure 6: Modeled costs of BDE Unit 8 and the Avalon CT, with burn-off cost breakout, NPV 2024$ millions[219]

[redacted]

(103) In examining the fuel burn-off issue with respect to the expansion plan scenario data provided by Hydro, we identified a possible inconsistency in the modeling. Given the significant impact of the fuel burn-off cost on the relative costs of the two resources, and the fact that – as shown in Figure 5 and Figure 6 – the total NPV cost of BDE Unit 8 is higher than that of the Avalon CT without

[218] Information Provided to Bates White.

[219] Information Provided to Bates White.

assumed burn-off, we expected scenario 4AEFC, which excludes the burn-off requirement, to show the Avalon CT selected in 2031 rather than BDE Unit 8. However, the results provided by Hydro do not show this; rather BDE Unit 8 is still shown in 2031 and the Avalon CT in 2035. To look at this question more closely, we calculated NPV costs for an alternative with the Avalon CT (excluding burn-off) starting in 2031, and BDE Unit 8 entering service in 2035. Our calculation shows the cost of this alternative as $13.7 million *lower* on an NPV basis than for the 4AEFC results provided by Hydro.[220] This does not appear consistent with the expansion model optimizing for the lowest-cost plan.

iv. Restrictions on Modeled Resource Options

(104) It is important to emphasize that beyond the cost and firm capacity contributions of alternative resources, Hydro's modeling imposed substantial restrictions on the resource combinations that could be selected to meet system needs. Significant restrictions in the Build Application analyses included the exclusion of BESS alternatives,[221] which we discuss below in Section F, and the specification that the Avalon CT addition would be modeled only as a single 141.6 MW addition.[222] The CT limitation was imposed despite the fact that the facility would consist of [redacted] with individual capacities of 47.2.[223] The limitation in the model to a single 141.6 MW addition, and no more, eliminated potentially useful information about alternative CT configurations of fewer, or more than, [redacted], particularly if selection of BESS alternatives were also allowed. Modeling also limited the addition of CT capacity to a maximum of 150 MW.[224]

F. Modeling Approach and Considerations

(105) The modeling performed by Hydro in developing and supporting the Build Application corresponds broadly to that for the RAP studies from 2018 through 2024. In summary terms, the methodology consisted of developing expansion plans to ensure sufficient system resources to meet the following planning objectives for the IIS:[225]

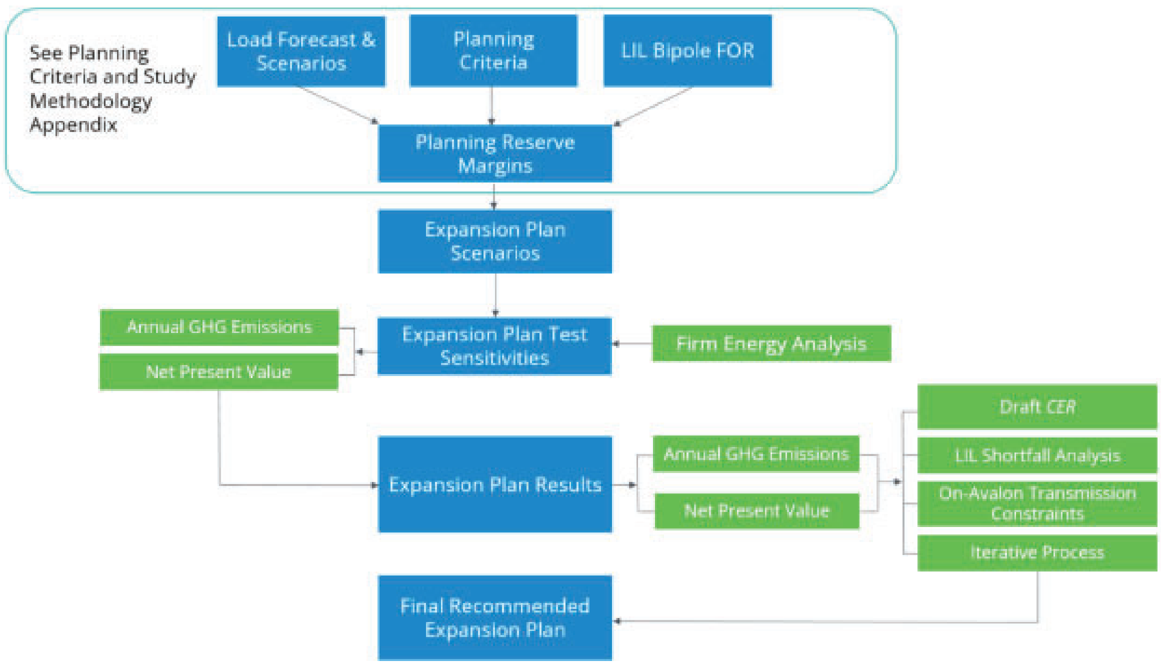
- A probabilistic reliability standard of no more than 2.8 hours per year of expected LOLH;
- Meet firm energy requirements;
- Meet operational reserve requirements;

[220] Information Provided to Bates White.
[221] Build Application, Schedule 3, page 16 lines 16 to 20 and page 28 lines 7 to 9.
[222] Information Provided to Bates White.
[223] Build Application, Schedule 5, Attachment 1, page 21; 2024 RAP Appendix C, footnote 96.
[224] Build Application, Schedule 1, page 16 lines 5 to 9.
[225] Build Application, Schedule 3, page 1 line 11 to page 2 line 6.

- Limit the loss of load to a "manageable level" during a LIL bipole outage event.

(106) The 2024 RAP study report presented a figure summarizing the overall development process, reproduced in Figure 7. The same overall process was applied in development of the Minimum Investment Required Expansion Plan that is the basis for the Build Application.

Figure 7: Hydro Expansion Plan Development Process[226]



(107) Key inputs to the expansion modeling include:[227]

- Load forecast scenarios
- Details of the existing IIS system and resources
- Reserve margins necessary to meet probabilistic planning criteria (2.8 LOLH) and operational reserves, including scenarios for different LIL equivalent forced outage rates ("EqFOR")
- Forecasted hydroelectric generation
- Development timing, firm capacity capability, operational characteristics, and costs for incremental resources to be evaluated
- Additional constraints imposed on resource alternatives available for the expansion model to select as solutions.

[226] 2024 RAP, Appendix C, Figure 2.

[227] 2024 RAP, Appendix B page 11 line 3 to page 12 line 8.

(108) As discussed in our review of the 2024 RAP, Hydro incorporates several distinct modeling tools in the development of these inputs and the evaluation of alternative expansion plans. These models include the Vista Model, used to produce hydroelectric generation forecasts, the Reliability Model (PLEXOS) to determine planning reserve margins,[228] the Firm Energy model to assess firm energy needs,[229] and the Resource Planning Model (PLEXOS),[230] to select resources. Bates White's review of application of these models in the 2024 RAP concluded that "each plays a key and necessary role in the planning process and, as described by Hydro, appears reasonable in their scope and approach."[231] Our conclusions are the same with respect to the models and general methods of evaluation performed in development of the Build Application.

(109) We find that Hydro has well-supported bases for the fundamental model inputs and assumptions regarding the load forecasts, the probabilistic planning criteria, the firm energy requirements, the LIL EqFOR cases, existing resources characteristics and hydroelectric forecasts, and the required reserve margins for the different cases examined. We also find that incorporation of the LIL Shortfall Analysis as an additional component of reliability planning is well-supported. With respect to the alternative supply resources considered, we find reasonable the construction, operational, firm capacity and base capital cost assumptions for incremental resources.

(110) As discussed above, we believe there is a problem in the way Management Reserves for BDE Unit 8 and the Avalon CT have been determined, and how the respective resource costs have been represented in the expansion model.

(111) With respect to the modeling approach, we have concerns regarding several distinct decisions implemented by Hydro. Specifically:

- Hydro has excluded from the analysis any costs associated with ensuring transmission capability on the Bay d'Espoir-Soldiers Pond corridor sufficient for BDE Unit 8 to meet the modeled reliability criteria – particularly in a LIL Shortfall event;
- Hydro has categorically excluded consideration of BESS alternatives as resource options available to the expansion model;
- Hydro has restricted the available option for new CT capacity on the Avalon to 141.6 MW at the Holyrood site, consisting of [redacted]. This assumption excludes potential resource expansions of fewer than, or more than, these three units.

[228] 2024 RAP, Appendix B, page 11 lines 8 to 10; *see also:* RAP Filing, Appendix B, section 5.1.
[229] 2024 RAP, Appendix B, page 12 line 1.
[230] 2024 RAP, Appendix B, page 12 lines 2 to 5.
[231] Bates White Assessment of 2024 RRA, page 35.

- In its LIL Shortfall Analysis, Hydro has modeled BDE8 in combination with the existing seven Bay d'Espoir generating units with no restriction on water availability.

(112) We discuss these restrictions (or lack of restriction in the case of BDE water availability) further below. In summary, the implications of these modeling decisions on expansion planning include the following:

- Excluding any costs for necessary transmission modifications in the evaluation of BDE Unit 8 is not reasonable. Hydro is identifying BDE Unit 8 as a necessary and least-cost resource for meeting reliability needs, including those during a LIL bipole outage, and is requesting more than $1 billion in Authorized Budget on the basis of its modeling. Excluding costs that will occur for certain, though in uncertain magnitude, is not appropriate.
- Similarly, the modeling of Bay d'Espoir output during a bipole outage with effectively no restriction on water availability may significantly overstate the ability of BDE Unit 8 in combination with the other BDE units to provide the reliability that the expansion model assumes.
- Not including batteries in at least an alternative scenario excludes potentially useful planning information – particularly if the restriction on CT additions only in one 141.6 MW amount is relaxed. An examination of batteries in combination with individual [redacted] additions could help inform Hydro's pending assessments of both battery alternatives and fuel supply options. While we understand Hydro's concern about the ability of batteries to provide capacity during a LIL bipole outage, the hourly shortfall results indicate the potential for effective charge/discharge cycles for batteries. If the hourly shortfall results are somehow not representative of real-world expectations during a bipole outage, that would draw into question the LIL Shortfall Analysis as a whole.
- Relaxing the restriction on CT additions for at least an alternative scenario could provide useful information about a broader range of On-Avalon capacity alternatives, particularly in tandem with batteries, as well as the fuel supply expansion alternatives.

G. Scenarios and Sensitivities

(113) Hydro conducted a total of 16 capacity expansion model runs based on two "scenarios" and eight "sensitivities." We address each scenario below.

i. Hydro's updated Expansion Plan scenarios represent a reasonable range of future conditions to assess the Build Application

(114) In the 2024 RAP, Hydro defined and modeled eight "scenarios," or future states that made specific assumptions about variables including the resource planning criteria, LIL equivalent forced outage

rate, and load forecast case; each scenario included a corresponding planning reserve margin, which is a function of the resource planning criteria and LIL equivalent forced outage rate.[232] These factors are all significant drivers of capacity need over the planning horizon, and variations in these drivers are important to consider and address via scenario analysis. In the Build Application, Hydro has updated two of those eight scenarios.[233] Both Scenario 1 and Scenario 4 plan to a resource planning criterion of 2.8 LOLH; however, Scenario 1 uses the Reference Case load forecast and a 5% LIL equivalent forced outage rate, while Scenario 4 uses the Slow Decarbonization Case load forecast and a 1% LIL equivalent forced outage rate.[234] Table 10 below shows the eight scenarios developed in the 2024 RAP. The scenarios that were updated in this Build Application (Scenarios 1 and 4) are shaded in green.

Table 10: Summary of Expansion Plan Scenarios[235]

Scenario	Capacity Planning Criteria (LOLH)	LIL Bipole EqFOR (%)	Planning Reserve Margin (%)	Island Load Forecast
1	2.8	5	25.8	Reference
2	2.8	5	25.8	Accelerated Decarbonization
3	2.8	5	25.8	Slow Decarbonization
4	2.8	1	17.1	Slow Decarbonization
5	2.8	10	29.1	Accelerated Decarbonization
6	2.8	1	17.1	Accelerated Decarbonization
7	0.1 LOLE	5	35.1	Slow Decarbonization
8	2.8	100	35	Reference

(115) Hydro's decision to update only Scenarios 1 and 4 was, in our view, reasonable, given the insights derived from the 2024 RAP capacity expansion modeling, which reviewed all eight scenarios in the table above.[236] Hydro's expected load case (the Reference case) and the load case Hydro uses to justify its Minimum Investment Required Expansion Plan (the Slow Decarbonization case) are important cases to update, whereas the high load case (Accelerated Decarbonization) is less useful at this time. Hydro already explored the incremental capacity needs and cost of the Accelerated Decarbonization case in the 2024 RAP.[237] As such, it is reasonable to not update any scenarios using the Accelerated Decarbonization case (Scenarios 2, 5, and 6). Hydro has already determined to continue to plan its system to a 2.8 LOLH resource planning criterion, making Scenario 7 unnecessary to update (given its 0.1 LOLE standard assumption).[238] Hydro also determined to not

[232] 2024 RAP, Plan Overview, page v lines 11 to 17 and Table 2.
[233] Build Application, Schedule 1, page 14 line 8.
[234] Build Application, Schedule 1, page 15 lines 1 to 14.
[235] 2024 RAP, Appendix C, Table 4.
[236] 2024 RAP, Scenario Summary Tables.
[237] *See, for example:* 2024 RAP, Appendix C, Section 6.3.1.1, Section 6.3.1.3, and Section 6.3.1.4.
[238] 2024 RAP, Appendix C, Table 4.

model the LIL as an energy-only line, which would increase Hydro's needed planning reserve margin to 35%; this makes Scenario 8 unnecessary to update for the Build Application.[239]

(116) Scenario 3 offers some potential value for update, as it is a moderated version of Scenarios 1 and 4. That is, Scenario 3 adopts Scenario 1's LIL equivalent forced outage rate (5%) and Scenario 4's load forecast case (Slow Decarbonization).[240] However, in our view, Hydro was correct to focus on the lower and upper bounds of its range of outcomes. Specifically, Hydro's purpose in developing the Minimum Investment Required Expansion Plan (Scenario 4) was to identify the lowest load case (Slow Decarbonization) and the most favorable assumption regarding LIL performance (i.e., a 1% equivalent forced outage rate).[241] This is the basis for a "minimum" investment required. Scenario 1, meanwhile, is a better estimation of the future conditions Hydro expects, with its base case load forecast (Reference Case) and elevated equivalent forced outage rate at the LIL (5%).[242]

(117) In our view, the Minimum Investment Required Case (Scenario 4) retains its merits as a representation of a future capacity demand scenario that entails the minimum near-term commitment to capacity investment. The assumed LOLH of 2.8 is the least stringent standard of those considered, and thus is appropriate for such a scenario. The assumed LIL reliability metric appears a reasonable upper bound as well and appears supported by the conclusions in the Haldar Report.[243] And, notwithstanding our comments on Hydro's load forecast above, Hydro appropriately applied the least aggressive, if not most likely, load forecast for the IIS. Thus, conceptually we agree with Hydro that, among the scenarios presented, Scenario 4 would be best suited to identify the portfolio that requires the Minimum Investment Required Expansion, in which BDE Unit 8 and the Avalon CT were included.

(118) Scenario 1 also provides useful insights, if only because it is Hydro's "expected" case.[244] It shows the substantial incremental impact on Hydro's needed planning reserve margin of planning for the Reference load forecast case and a 5% LIL equivalent forced outage rate, with Hydro's implied planning reserve margin increasing from 17.1% (in Scenario 4) to 25.8% (Scenario 1).[245] Detailed results across the various modeling scenarios elaborate on the differences in incremental capacity requirements and costs.[246] We address these later in our report.

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[239] 2024 RAP, Appendix C, Table 4 and footnote 90.

[240] 2024 RAP, Appendix C, page 47, lines 5 to 8.

[241] 2024 RAP, Plan Overview, Table 2.

[242] 2024 RAP, Plan Overview, page 33, lines 25 to 28 and Table 2.

[243] Haldar & Associates, Inc., "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," as revised April 11, 2021 ("Haldar Report"), page ii. Included as Attachment 1 to Hydro, "Labrador-Island Link Reliability Assessment – Summary Report," March 12, 2021.

[244] Build Application, Schedule 1, page 15 line 3.

[245] 2024 RAP, Plan Overview, Table 2.

[246] *See:* 2024 RAP, Plan Overview, Table 3.

(119) Notwithstanding our earlier cautions regarding the uncertainty surrounding the Reference Case in the load forecast, our final point regarding Hydro's selected modeling scenarios is only to underscore that Hydro has put forth an expansion plan that does not meet Hydro's resource planning criteria given expected future conditions. The Minimum Investment Required Expansion Plan *does not meet* the 2.8 LOLH standard when using the Reference Case load forecast and a 5% LIL bipole equivalent forced outage rate.[247] This necessarily implies that while the proffered expansion plan will be helpful in meeting future reliability needs, it will be insufficient. This may represent an innovative approach to resource planning and procurement that departs from a more traditional approach of proposing complete solutions to expected capacity shortfalls. We do note that the two proposed investments in this Build Application – BDE Unit 8 and the Avalon CT – are identified in Scenario 1 modeling results as well, suggesting that this innovative approach is not resulting in *different* resource selections, just fewer.[248] Nevertheless, Hydro must closely monitor its load and supply resource forecasts, as well as LIL performance and expectations, to ensure its expansion investments are keeping up with its needs and are optimal, given expected future conditions.

ii. Hydro's capacity expansion model sensitivities represent a useful, albeit potentially incomplete, set of assumptions

(120) In the 2024 RAP, Hydro defined and modeled eleven "sensitivities" designed to "test select scenarios."[249] The sensitivities allowed key parameters to vary, including hydro capital costs, CT capital costs, CT fuel and operating costs, and BESS ELCCs, plus additional sensitivities where certain resources are forced into the portfolio (wind, Newfoundland Power GTs) or precluded from selection (BESS).[250]

(121) In the Build Application, Hydro has dispensed with ten of those eleven sensitivities, focusing instead on Sensitivity AEF, which "considers a fixed wind profile to meet [Hydro's] firm energy criteria, excludes batteries as a resource option, and limits the number of CTs that can be constructed to one, approximately 150 MW On-Avalon CT in consideration of current diesel fuel supply availability on the Island."[251] Hydro explained that it selected Sensitivity AEF because "the recommended Expansion Plan that was put forward [in the 2024 RAP] was Scenario 4AEF(ADV) (Minimum Investment Required)."[252] For the Build Application, Hydro added seven new sensitivities, which begin with the AEF Sensitivity and test certain variable changes, such as higher capital and fuel costs,

[247] 2024 RAP, Appendix C, page 145, line 3 to page 146 line 1; Build Application, Schedule 1, page 5 lines 6 to 8.
[248] Build Application, Schedule 3, Table 4.
[249] Build Application, Schedule 3, page 16 line 14.
[250] 2024 RAP, Appendix C, page 48 lines 4 to 6 and Table 5.
[251] Build Application, Schedule 3, page 16 lines 16 to 20.
[252] Build Application, Schedule 3, page 16 lines 15 to 16.

removal of forced fuel burn-off at the Avalon CT, and inclusion of a tax credit. The table below shows the eight sensitivities used in the Build Application.

Table 11: Summary of Expansion Plan Sensitivities[253]

Sensitivity	Description
AEF	Fixed wind profile to meet firm energy criteria, removes batteries as a resource option, and limits CT additions to 150 MW in consideration of current diesel fuel supply availability on the Island
AEFC	A combination of Sensitivities AEF and C to determine the impact of removing forced CT fuel burn-off
AEFD	Same as Sensitivity AEF with the exception of including the P85 costs for BDE Unit 8 and other hydro resource options
AEFG	A combination of Sensitivities AEF and G to determine the impact of increasing CT fuel costs to $2.05/L in consideration of potential future volatility in fuel costs
AEFH	Same as Sensitivity AEF with the exception of including P85 costs for the Avalon CT
AEFDH	A combination of Sensitivities AEF, D and H to determine the impact of an increase in costs for both BDE Unit 8 and the Avalon CT, by including the P85 costs for both BDE Unit 8 and the Avalon CT
AEFGH	A combination of Sensitivities AEF, G and H to determine the impact of increasing the CT capital cost in addition to an increase in CT fuel costs
AEFJ	Same as Sensitivity AEF with the exception of including the potential for the Clean Electricity Investment Tax Credit cost savings

(122) Hydro's selected sensitivities provide useful data in assessing the Build Application. We agree, for example, that Hydro's decision to select the AEF sensitivity is sensible, as it was the primary sensitivity in the 2024 RAP on which the recommended expansion plan was based.[254] This approach encourages some continuity between the 2024 RAP and the Build Application.

(123) That said, while it is reasonable to begin with the AEF sensitivity as a starting point for the Build Application, that does not mean the assumptions that make up the AEF sensitivity are necessarily sufficient to allow the Board to decide on the Build Application. Further modeling and testing is required, and it is incumbent on Hydro to provide adequate modeling to support the requested investments in BDE Unit 8 and the Avalon CT.

(124) In our view, Hydro provided some useful model runs and related information. Sensitivity AEFC, for example, removes the required "burn-off" of ten days of fuel at the Avalon CT.[255] This is an important sensitivity to test, as there is the potential to pursue commercial arrangements or storage/physical solutions to extend the shelf life of the fuel (and thereby mitigate or remove the need for annual forced burn-off of fuel). Hydro explains that it is continuing to study this issue and that the 10-day annual forced burn-off requirement modeled in sensitivity AEF (and other sensitivities) is a "worst-case scenario."[256] The modeling results (addressed further below) demonstrate the materiality of this assumption: removing it reduces the NPV of the incremental revenue requirement by $153.9

[253] Build Application, Schedule 3, Table 3.
[254] 2024 RAP, Appendix C, page 157 line 11.
[255] Build Application, Schedule 3, Section 5.2.1.1.2, and Table 3.
[256] Build Application, Schedule 3, page 20 lines 25 to 28.

million in Scenario 4 and $191.4 million in Scenario 1.[257] While this value is likely not to impact the Build Application (as it relates to the selection of the Avalon CT), it does identify the magnitude of costs at stake and argues for prudent efforts by Hydro to avoid incurring these costs, if possible. This would include optimizing the timing of the forced fuel burn-off (and related scheduled fuel deliveries), since in burning off the fuel, the Avalon CT would be expected to provide generation output to the grid.

(125) Hydro has also appropriately included sensitivities that seek to determine the impact of higher capital costs for both new hydroelectric resource options (including BDE Unit 8) and the Avalon CT, as well as higher fuel costs. As a preliminary matter and as noted earlier in this report, Hydro began by utilizing the refined Class 3 P50 (or P55) estimates for BDE Unit 8 and the Avalon CT, an increase in precision compared to the Class 5 estimates used in the 2024 RAP.[258] These estimates indicate higher total project costs compared to those used in the 2024 RAP. Other supply stack options use escalated Class 5 cost estimates.[259] This update led to an inflation-adjusted[260] increase in capital costs of [redacted] million for BDE Unit 8, an increase of [redacted], and [redacted] for the Avalon CT, an increase of [redacted], from the 2024 RAP Class 5 estimates.[261] Hydro also added escalation and interest during construction to these values. These values were [redacted] million and [redacted] million, respectively, for BDE Unit 8,[262] and [redacted] million and [redacted] million, respectively, for the Avalon CT.[263] Lastly, to derive the "Management Reserve" of both projects, Hydro took the P85 Class 3 cost estimate and subtracted off the P50/P55 values (plus escalation and interest during construction).[264] The resulting Management Reserve is [redacted] million for BDE Unit 8[265] and [redacted] million for the Avalon CT.[266]

[257] Information Provided to Bates White. Scenario 1AEF has an NPV of $6.68 billion, indicating removing the fuel burn-off reduces costs by roughly 2.9% to an NPV for 1AEFC of $6.49 billion. Scenario 4AEF has an NPV of $3.32 billion, indicating removing the fuel burn-off reduces costs by roughly 4.6% to an NPV for 4AEFC of $3.16 billion.

[258] Build Application, Schedule 1, page 29, lines 21 to 28.

[259] Build Application, Schedule 3, page 12 lines 16 to 18.

[260] The 2024 RAP utilized 2023 dollars, while the Build Application utilizes 2024 dollars. The CPI inflation rate between 2023 and 2024 is calculated to be 2.42%. Statistics Canada, "Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted," January 21, 2025, available at: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501.

[261] Information Provided to Bates White. Build Application, Schedule 5, Appendix B, Table 1; Build Application, Schedule 4, Appendix A, Table 1; Build Application, Schedule 3, Table 1; Statistics Canada, "Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted," January 21, 2025, available at: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501. For this comparison, cost estimates from the Build Application use the "Planned Budget" line item. The Total Cost Estimate reflects the P85 estimate, with the Management Reserve line item bridging the gap between the P50 estimate for BDE Unit 8 and P55 estimate for ACT to the respective P85 estimates for the two assets. Information Provided to Bates White; Build Application, Schedule 5 Attachment 1, page 1. These figures from the Build Application follow Table 4 above, excluding IDC and including contingencies, thereby aligning the estimates with those in the 2024 RAP.

[262] Build Application, Schedule 4, Attachment 1, Table 1.

[263] Build Application, Schedule 5, Attachment 1, Table 1.

[264] Information Provided to Bates White; Build Application, Schedule 5, Attachment 1, page 1.

[265] Build Application, Schedule 4, Attachment 1, Table 1.

[266] Build Application, Schedule 5, Attachment 1, Table 1.

(126) For the "high" capital cost sensitivities (AEFD, AEFH, AEFDH, and AEFGH), Hydro used the P85 values for each project—that is, $1.08 billion for BDE Unit 8 and $891 million for the Avalon CT,[267] subject to the discussion above regarding the development of these estimates. These values also equal the requested cost recovery by Hydro from ratepayers in the Build Application.[268] It is important for Hydro to have provided sensitivities to demonstrate the impact on the modeling and outputs of using the actual costs being requested for recovery. These sensitivities show, for example, that under Scenario 4, the NPV of the incremental revenue requirements across these four sensitivities increase by $108.3 million to $230.9 million, or 3.3% to 7.0%, using the P85 capital costs.[269] In Scenario 1, NPVs increase by $124.0 million up to $370.4 million (or 1.9% to 5.5%) across these four sensitivities.[270]

(127) The "high" fuel price sensitivity also provides useful insight on the impact of higher fuel costs on the incremental revenue requirement. Sensitivity AEFG, which increases fuel prices from current levels by about 55%,[271] produces incremental revenue requirements that increase by $82.0 million (or 2.5%) in Scenario 4 and $227.7 million (or 3.4%) in Scenario 1.[272]

(128) The selected sensitivities are, however, incomplete to some degree. First, regarding the "high" cost sensitivities, we note that these cases reflect the exact requested costs contained in the Build Application. We understand that the requested amounts in the Build Application include contingency reserve and Management Reserve, which would not be needed to incur and recover if project costs matched the P50/P55 values identified in the Build Application.[273] However, even with a P85 estimate, there is inherently a 15% chance Hydro's final costs will exceed the P85 estimates (which include all costs requested in the Build Application and modeled in the "high" cost sensitivities).[274]

(129) Moreover, once the cost estimates have been adjusted for moving from Class 5 to Class 3 estimates, the degree of the "high" sensitivity case has significantly decreased from the 2024 RAP model runs. Specifically, in the 2024 RAP, Hydro included sensitivities where BDE Unit 8 and Avalon CT capital costs increased by 50% (or more).[275] In the Build Application, Hydro's "high" capital cost cases only

[267] Build Application, Schedule 3, Table 3.
[268] Build Application, Schedule 1, page 38 lines 6 and 7, and page 43 lines 24 and 25.
[269] Information Provided to Bates White.
[270] Information Provided to Bates White.
[271] Build Application, Schedule 3, footnote 29.
[272] Information Provided to Bates White.
[273] Build Application, Schedule 5, Attachment 1, page 1.
[274] Build Application, Schedule 1, footnote 39.
[275] 2024 RAP, Appendix C, Table 5.

increase the costs of BDE Unit 8 and the Avalon CT by [redacted][276] and [redacted],[277] respectively. Such additional sensitivities are likely unnecessary, as they would only demonstrate higher costs.

(130) Second, Hydro's sensitivities ignored potential supply resource alternatives, including BESS resources. Regarding BESS resources, Hydro states:

> Based on analysis performed by [Hydro] as part of the RRA Study Review, [BESS resources] 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 ELCC to inform the 2026 Resource Adequacy Plan.[278]

(131) Hydro has also noted that it is undergoing a "Battery Feasibility Study" to "inform the 2026 Resource Adequacy Plan supply stack" to examine the "practicality and viability of the [BESS] project," with "engineering [being] advanced to a level appropriate to commence FEED if the project is deemed viable."[279]

(132) In our view, it is a shortcoming of the Build Application that BESS resources were not included as supply options for any of the 16 capacity expansion scenario/sensitivity model runs, nor any of the LIL Shortfall Analysis model runs (addressed later in this report). We recommended in our August 2024 report that Hydro not dismiss BESS resources as an option,[280] noting that BESS resources were selected in five of 12 capacity expansion model runs in which BESS resources were able to be selected by the model, selected before BDE Unit 8 and the Avalon CT, depending on the sensitivity being run.[281] We further noted that BESS resources performed particularly well in cases where BESS ELCCs were assumed to be 60% or higher (not the 40% baseline assumption), which were more consistent with recent real world examples.[282]

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[276] The total direct and indirect construction costs [redacted] million), plus contingency costs ([redacted] million), plus escalation ([redacted] million), plus interest during construction ([redacted] million) produces a total capital cost of [redacted] million for BDE Unit 8. The P85 cost ([redacted] million), calculated by adding a Management Reserve of [redacted] million, represents an increase of [redacted] from [redacted] million. Build Application, Schedule 4, Attachment 1, Table 1, pages 16 to 24.

[277] The direct construction costs ([redacted] million), plus indirect construction costs ([redacted] million), plus contingency costs ([redacted] million), plus escalation ([redacted] million), plus interest during construction ([redacted] million) produces a total capital cost of [redacted] million for the Avalon CT. The P85 cost ([redacted] million) represents an increase of [redacted] from [redacted] million. Build Application, Schedule 5, Attachment 1, Table 1.

[278] Build Application, Schedule 1, footnote 26.

[279] Build Application, Schedule 2, page 10.

[280] Bates White Assessment of 2024 RRA, page 41.

[281] Bates White Assessment of 2024 RRA, page 41; 2024 RAP Appendix C, Section 6.2.1.1.7.

[282] Bates White Assessment of 2024 RRA, page 41; National Renewable Energy Labs ("NREL"), "Moving Beyond 4-Hour Li-ion Batteries: Challenges and Opportunities for Long(er)-Duration Energy Storage," September 2023, page 12, available at: https://www.nrel.gov/docs/fy23osti/85878.pdf.

(133) Hydro's position regarding "feasibility questions surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole" seems to be the primary driver for not testing the economics of the Minimum Investment Required Expansion (including BDE Unit 8 and the Avalon CT) against more fulsome alternatives, such as BESS resources. We address this point below. Regardless of LIL Shortfall Results, it would have been a considerable improvement to the Build Application for Hydro to have assessed the cost differences between portfolios that contain BESS resources with that of the proffered investments in BDE Unit 8 and the Avalon CT.

(134) Our third point is related to this idea. Hydro's selected sensitivities do not include a review of the impact of delayed retirements at its existing thermal generating stations, including Holyrood TGS. As we explain above, Hydro has plans to retire its existing thermal generating assets (including Holyrood TGS) only when three conditions are met, including that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.[283] As a result, there are multiple future states in which Holyrood TGS will not be retired in a timely fashion and could remain in service into 2035. For example, any delay in new generating resources reaching commercial operations would delay retirement of the existing thermal assets. High and/or volatile equivalent forced outage rates on the LIL will also delay retirement of Holyrood TGS.

(135) Given the possibility of delays to Holyrood TGS beyond 2030 even with the nearly $2 billion of investment in new generation being requested in the Build Application, it is reasonable to wonder: at what point does the cost of the proposed investments in BDE Unit 8 and/or the Avalon CT become less economically attractive than viable alternatives? For example, if BDE Unit 8 was to be modeled at a cost of $2 billion, would it still be selected? The answer may still be yes, since no other non-hydroelectric alternatives are considered. Sensitivity AEF (and every other sensitivity modeled in the Build Application) prohibit BESS resources and CT resources (beyond the 150 MW being put forth in the Build Application already) from being selected by the model.[284] It may be that BESS resources are less effective in managing an extended LIL bipole outage than BDE Unit 8 and/or the Avalon CT, but at some point, as BDE Unit 8's and/or the Avalon CT's expected costs rise, BESS resources' purported shortcomings may be worth the savings. Similarly, additional CT resources may require additional fuel infrastructure development, as Hydro has asserted,[285] but at some point as BDE Unit 8's expected costs rise, these additional fuel infrastructure investments may be worthwhile.[286] The shortcoming of Hydro's modeling in its Build Application is that it fails to provide the Board and stakeholders with the cost threshold point at which these alternatives become economic (if they are not already).

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[283] Build Application, Schedule 1, footnote 27.
[284] Build Application, Schedule 3, Table 3.
[285] Build Application, Schedule 3, page 16 lines 18 to 20.
[286] *See, for example*: 2024 RRA, Section 6.2.2.1.8, *or* Section 6.2.2.1.12.

(136) This shortcoming also presents itself in the instance of a scenario where the Avalon CT and/or BDE Unit 8 suffers from development delays. Consider a future where one needed capital project (e.g., the Avalon CT) is constructed and commissioned on time, while the other needed capital project (e.g., BDE Unit 8) suffers from delays which prevent its commissioning into 2033. Hydro has made it clear that in such an instance, Holyrood would not be retired prior to 2033 at the earliest.[287] In this case, Hydro would continue to rely on Holyrood, which would cost up to $150.8 million/year, as currently forecasted by Hydro.[288] Hydro's Build Application does not provide sufficient evidence to understand at what point alternatives become economically preferable to this scenario. Such alternatives could include building (1) 50-150 MW of standalone BESS resources, (2) 150 MW of additional CT capacity on the Avalon (with needed fuel infrastructure investments), or (3) 75 MW of additional On-Avalon CT resources paired with 75 MW of 6-hour duration BESS.

H. LIL Shortfall Analysis

(137) As explained above, Hydro conducted a LIL Shortfall Analysis to assess the impact of a six-week winter outage of the LIL. In this section, we assess the assumptions and modeling approach of that analysis. Overall, we find that the LIL Shortfall Analysis was conducted reasonably and provides useful data for informing the resource portfolio needed, though is based upon certain simplifying assumptions.

(138) As a preliminary matter, we note that Hydro has maintained the same modeling approach and overall set of assumptions as was used in the 2024 RAP. We observed no material changes to the LIL Shortfall Analysis approach or assumptions.

(139) The LIL Shortfall Analysis contains several reasonable assumptions. First, it assumes that the length of the outage is six weeks, which Hydro has derived from past studies of the LIL's risks and reliability as well as expected restoration times following an outage.[289] Hydro has stated that a six-week outage is the "worst case scenario,"[290] though acknowledges that an outage could last longer than six weeks.[291] Still, Hydro's decision to model a six-week outage is a reasonable scenario grounded in studies of LIL already completed. Second, Hydro selected the period beginning January 1, 2032 and ending February 11, 2032 for the modeling period.[292] This is another reasonable decision, as it focuses on peak winter conditions and a year that is within the planning period. Third, the LIL Shortfall Analysis applied probabilistic analyses to weather, load, unit outages, and renewable

[287] Build Application, Schedule 3, page 44 lines 2 to 4.
[288] Information Provided to Bates White.
[289] Build Application, Schedule 3, footnote 58.
[290] 2024 RAP Technical Conference #1, slide 53.
[291] Build Application, Schedule 3, page 37 lines 13 to 14.
[292] Information Provided to Bates White.

generation output which considered 2,400 random combinations of these factors.[293] Hydro considers both the "Average Case" (where the average of the probabilistic outcomes are used) and the "Severe Case" (where the probabilistic outcomes are unfavorable (e.g., severe weather, poor unit availability) and to be exceeded 10% of the time in the analysis).[294] Fourth, the "shortfall" is defined as the amount of load shedding required to restore a minimum regulating reserve of 70 MW on the Island Interconnected System.[295] This value (70 MW) was determined in a filing with the Board in 2019 ("TP-TN-068 – Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage"); Hydro maintains "a minimum reserve of 70 MW within the Island system when the LIL is out of service to provide for acceptable frequency regulation."[296] Fifth, Hydro conducted the LIL Shortfall Analysis across three "combinations" of load forecasts and expansion plans: Combination 1, which uses the Slow Decarbonization load forecast and Scenario 4AEF (Minimum Investment Required); Combination 2, which is the same as Combination 1, except the Avalon CT is advanced from 2035 to 2031 (Scenario 4AEF(ADV); and Combination 3, which uses the Reference Case load forecast and the Scenario 4AEF(ADV) expansion plan.[297] These three combinations allow for a comparison of the capacity expansion model optimal portfolio (which builds the Avalon CT in 2035) against the portfolio where the Avalon CT is advanced to 2031, since the modeled period in the LIL Shortfall Analysis is in the winter of 2032.

(140) There are other modeling characteristics and assumptions that are simplifying in nature that necessarily impact the LIL Shortfall Analysis results and must be considered when drawing conclusions from that analysis.

(141) First, the LIL Shortfall Analysis assumes no new hydrological constraints associated with output from the Bay d'Espoir generating facility.[298] Hydro states that the maximum output of Bay d'Espoir, including BDE Unit 8, would be 767.8 MWh.[299] Hydro's LIL Shortfall Analysis results are consistent with this limitation, with no hours in which Bay d'Espoir's collective output exceeds 767.8 MW.[300] Hydro states that Bay d'Espoir produces 432.9 MWh for each million cubic meter ("MCM") of water consumed.[301] The LIL Shortfall Analysis results show that Bay d'Espoir is modeled to produce an

[293] Build Application, Schedule 3, footnote 59.
[294] Build Application, Schedule 3, page 37 line 19 to page 38 line 3.
[295] Build Application, Schedule 3, page 37 lines 16 to 17.
[296] Hydro, "Reliability and Resource Adequacy Study 2019 Update," November 15, 2019, Volume III, page 33 lines 9 to 11.
[297] Build Application, Schedule 3, page 38 lines 12 to 20.
[298] Information Provided to Bates White.
[299] Information Provided to Bates White.
[300] Information Provided to Bates White.
[301] Hydro May 27, 2025 email to Bates White.

average of 685.9 GWh during the six week outage across all model runs in the Combination 2 scenario,[302] which translates to consumption of approximately 1,597 MCM of water.

(142) Hydro also explains that the Maximum Operating Level of the Long Pond Reservoir (which supplies Bay d'Espoir) is 738 MCM in the winter season.[303] That amount is further limited by the minimum storage level of 355 MCM.[304] This suggests that the Long Pond Reservoir would have a maximum volume of 738 MCM entering winter and could release up to 383 MCM for consumption at Bay d'Espoir, far less than the 1,597 MCM modeled to be consumed at Bay d'Espoir in the LIL Shortfall Analysis. This gap is shown below in Figure 7. Since the existing storage at Long Pond is insufficient to support Bay d'Espoir's modeled output during a LIL shortfall, the reservoir will necessarily require substantial inflows to support modeled output at the plant. Notably, these inflows would be needed just to support the existing Bay d'Espoir units (1-7), let alone any incremental output from BDE Unit 8. Hydro has described winter as the "low inflow season"[305] and the "dry winter period (January and February),"[306] meaning the plant would need to tap its limited storage resources, including any supply from other reservoirs, to operate as planned.

[302] Information Provided to Bates White.

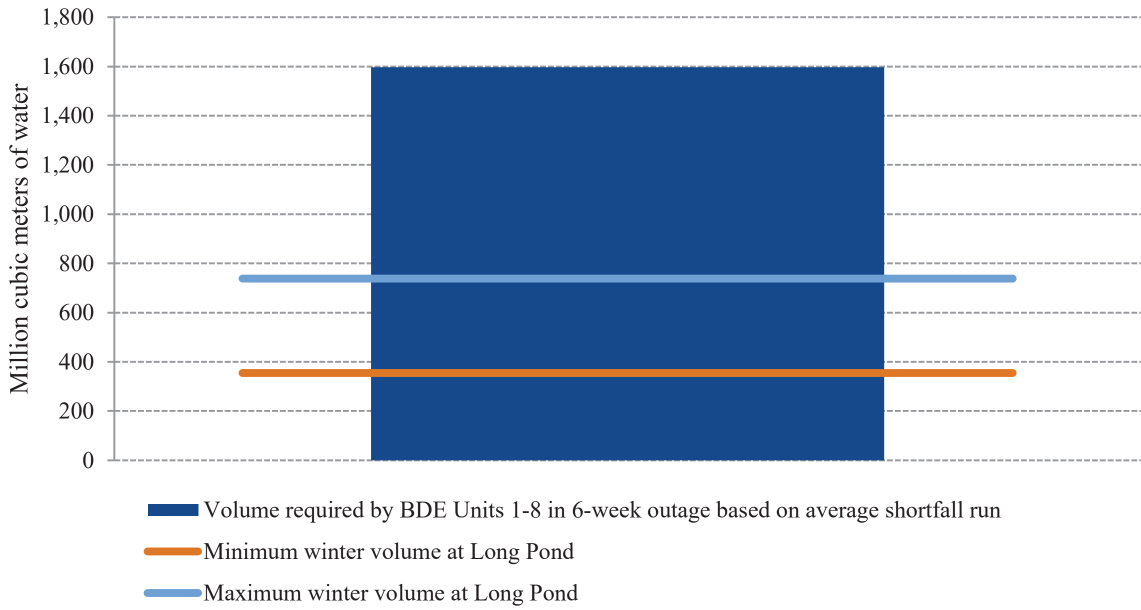
[303] Information Provided to Bates White.

[304] Information Provided to Bates White.

[305] Hydro, "Reliability and Resource Adequacy Review – Island Hydro Electric Supply Refresh Study," October 1, 2024, page 6 line 19.

[306] Hydro, "Reliability and Resource Adequacy Review – Island Hydro Electric Supply Refresh Study," October 1, 2024, Attachment 1, page 36.

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



(143) Hydro has not fully addressed this issue in detail in its Build Application. The March 2025 Hatch study (included in the Build Application)[308] contained historical inflow data at BDE.[309] However, that data was provided on an annual average basis which prevents assessment of seasonal inflows. In its 2024 RAP, Hydro also provided Bay d'Espoir's average and firm energy capability given the most adverse three-year sequence of inflows in its historical record, which suggested average annual capability of 2,650 GWh and average annual firm capability of 2,096 GWh.[310] But this data, while useful, does not contain any seasonal granularity.

(144) Even ignoring seasonality, the annual inflow data suggests that there may be hydrological limitations to Bay d'Espoir's ability to generate at output levels assumed in the LIL Shortfall Analysis. The LIL Shortfall Analysis shows that the Bay d'Espoir generating plant will need to consume 1,597 MCM for the six-week period, or about 266 MCM/week. The March 2025 Hatch study contains a figure that suggests annual inflows were just over 500 cubic meters/second in 2019 and just under 400 cubic meters/second in 2017.[311] Converting these to weekly inflow units results in average weekly inflows of about 242 MCM/week (in 2017) and 302 MCM/week (in 2019).[312] These *average annual* inflows

[307] Information Provided to Bates White.

[308] Build Application, Schedule 1, Attachment 2.

[309] Build Application, Schedule 1, Attachment 2, Figure 2-3.

[310] 2024 RAP, Appendix B, Table 13.

[311] Build Application, Schedule 1, Attachment 2, Figure 2-3.

[312] The conversion for 2017 equals 400 cubic meters/second * 60 seconds * 60 minutes * 24 hours * 7 days ÷ 1,000,000 = 241.92 MCM/week. For 2019, 500 cubic meters/second * 60 seconds * 60 minutes * 24 hours * 7 days ÷ 1,000,000 = 302.40 MCM/week.

may not be enough to sustain Bay d'Espoir's operations as contemplated in the LIL Shortfall Analysis. Adjusting these average annual data for winter inflows, the "low inflow season" and "dry winter period (January and February)," as described by Hydro, only increases the risk.

(145) As it stands, therefore, and absent additional evidentiary support from Hydro, the LIL Shortfall Analysis may overstate the reliability contribution of BDE Unit 8 to an extended bipole outage of the LIL. It is not clear from the data that the collective plant can produce the level of output assumed in the analysis. Hydro should address this issue in this proceeding to enhance confidence that its hydrological resources and expected inflows are sufficient to meet the demands of producing 685.9 GWh in a six-week winter outage, as is modeled in the LIL Shortfall Analysis.[313] To the extent that hydrological limitations bind the output of Bay d'Espoir in such a scenario, the incremental addition of another generating unit (i.e., BDE Unit 8) would seem to have limited positive impact.

(146) Second, even ignoring any hydrological constraints, the assumed output of Bay d'Espoir in the LIL Shortfall Analysis is far above the historical average generation of the plant. Since January 1, 2015, the *highest* rolling six-week output of the collective Bay d'Espoir plant (units 1-7) is 464.21 GWh.[314] This six-week output from the plant would still be about 33 percent below the modeled output in the LIL Shortfall Analysis (691.4 GWh).[315] A review of Bay d'Espoir's historical and projected capacity factors underscores this point. Since 2015, Bay d'Espoir's collective capacity factor has averaged 49.4%.[316] The LIL Shortfall Analysis results in a collective capacity factor for the plant of 89.3% over the six-week period.[317] All this suggests that the LIL Shortfall Analysis is conditioned upon unprecedented performance from Bay d'Espoir. A comparison of how the forecasted generation of BDE in NLH's LIL shortfall against past performance is shown below in Table 12.

Table 12: Historic capacity factors of BDE1-7 and expected capacity factor of BDE1-8 in LIL Shortfall[318]

Average capacity factor of BDE 1-7	Highest single day capacity factor of BDE 1-7	Highest 6-week capacity factor of BDE 1-7	Assumed 6-week capacity factor of BDE 1-8 in LIL Shortfall
49.41%	91.64%	75.03%	**89.33%**

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

[313] Information Provided to Bates White.

[314] This output occurred between February 14, 2022 and March 27, 2022. Over this 6-week period, 19,342.20 MW were generated. 19,342.20 MW * 24 hr ÷ 1000 MWh/GWh = 464.21 GWh. Information Provided to Bates White.

[315] Information Provided to Bates White.

[316] Information Provided to Bates White.

[317] Information Provided to Bates White.

[318] Information Provided to Bates White.

replenishment. This takes time, and as storage levels are restored, it is possible that the plant would be derated (due to limited water), which could cause resource adequacy and reliability issues on the system.

(148) Fourth, the analysis does not consider transmission constraints, which Hydro expressly acknowledges in the Build Application.[319] Through meetings with Hydro, we confirmed that the current transmission system is insufficient to allow for full transfer of all output from Bay d'Espoir (including BDE Unit 8) to the Avalon during a LIL bipole outage.[320] Specifically, the BDE-SOP 230 kV transmission system is currently limited to a maximum west-to-east flow of 603 MW, which is approximately equal to the maximum current output at Bay d'Espoir.[321] Without further transmission upgrades or new operational schemes, the grid cannot deliver any additional flow from Bay d'Espoir that would be possible from the addition of BDE Unit 8.

(149) Hydro noted that its consultant (TransGrid) developed a menu of options that would alleviate the transmission constraint, with the lowest cost option being $150 million.[322] However, Hydro has not proposed this transmission solution in the Build Application (or elsewhere), and is instead working with TransGrid to explore "alternative steps to maximize transfer capacity through existing assets, including the implementation of a [remedial action scheme] and/or [dynamic line rating] technology."[323] Hydro states that these alternatives would be "technically equivalent" to the $150 million transmission upgrades.[324] Hydro states that the TransGrid study is scheduled to be completed by the end of the second quarter of 2025.[325] It is worth noting, therefore, that the Build Application does not provide a definitive position on the deliverability of the output of BDE Unit 8, since deliverability requires transmission investment or operational schemes that remain under study.

(150) Fifth, the LIL Shortfall Analysis assumes no constraints associated with fueling the Avalon CT, which may be an aggressive assumption. The LIL Shortfall Analysis shows that for the 4AEF(ADV) combination, the Avalon CT is expected to produce up to 34.1 GWh during the six-week period.[326] Hydro explains that the unit will consume 33,579 liters of diesel fuel per hour at maximum capacity.[327] This roughly translates to consumption of 237.1 liters/MWh; thus, for production of 34.1 GWh, the Avalon CT would expected to consume 8,076,047 liters of diesel fuel.[328] Hydro's tank

[319] Build Application, Schedule 3, page 38 lines 4 to 5.

[320] Information Provided to Bates White.

[321] Information Provided to Bates White; *see also*: 2024 RAP, Appendix C, Table 40.

[322] Build Application, Schedule 3, page 50 lines 4 to 6.

[323] Build Application, Schedule 3, page 50 lines 9 to 10.

[324] Build Application, Schedule 3, page 50 line 11.

[325] Build Application, Schedule 3, page 50 lines 24 to 25.

[326] Information Provided to Bates White.

[327] Information Provided to Bates White.

[328] This is a rough approximation, as it assumes a constant fuel consumption rate (liters/hour) based on operation at maximum output.

infrastructure proposed within the Build Application[329] has a combined capacity of approximately 9,600,000 liters of diesel fuel.[330] Even reducing this amount by the "dead storage," or minimum volume of stored diesel in the tanks, of 960,000 liters (or 10% of the total tank storage),[331] Hydro would have sufficient capacity (~8,640,000 liters) to cover maximum consumption implied by the LIL Shortfall Analysis results (~8,076,047 liters).

(151) Still, if the Avalon CT is less efficient, or the outage lasts longer, or the unit is operated at a higher capacity factor – even at the maximum output across all simulations, the Avalon CT's highest achieved capacity factor over six weeks is just 23.9% in the LIL Shortfall Analysis[332] – Hydro may need to refuel the Avalon CT during the outage. Moreover, Hydro has taken the simplifying assumption that "sufficient fuel is available when required,"[333] suggesting an extended LIL outage event may put additional refueling stress on the supply network which has not been modeled. Hydro has provided assurance in its Build Application that "[t]he addition of a 150 MW CT is confirmed to be feasible in consideration of the existing fuel supply chain on the Island of Newfoundland."[334] However, the issue of the risk of securing a reliable fuel supply has been a focus in the 2024 RAP, and though Hydro commissioned two studies which confirmed the selection of diesel as the optimal fuel for a CT, those studies identified potential challenges in securing long-term supply of diesel due to limitations in existing infrastructure, supply chain challenges, and potential future regulation addressing diesel fuels.[335] In its Build Application, Hydro's consultant (Hatch Ltd.) identifies the risk that "[f]uel suppliers may be unable to provide sufficient fuel supply" as an "active" risk that "could result in insufficient fuel supply, or additional fuel costs."[336] At no point would the risk of insufficient fuel supply or additional fuel costs likely be greater than during a prolonged LIL outage during the winter season. As such, Hydro should provide additional detail about its fuel contracting status and its plans for mitigating the risk of insufficient fuel supply during a prolonged LIL outage.

(152) Sixth, the LIL Shortfall Analysis does not assess the efficacy or value of BESS resources. In fact, as explained above, BESS resources were also precluded from the capacity expansion modeling scenarios underpinning the Build Application. Hydro explains that "there remain appreciable

[329] Build Application, Schedule 5, page 6 lines 15 to 16.

[330] Information Provided to Bates White.

[331] Information Provided to Bates White.

[332] Information Provided to Bates White. The ACT is rated at 141.6 MW. Over six weeks of generating, the greatest output is approximately approximating 34.06 GWh, or an hourly average of 33.79 MW. Information Provided to Bates White.

[333] NP-NLH-104(c).

[334] Build Application, Schedule 1, page 11 lines 9 to 11.

[335] *See, for example*: 2024 RAP, Appendix C, Attachment 4, Section 7; *see also:* Hydro, "Reliability and Resource Adequacy Study Review – Combustion Turbine Feasibility Study," October 13, 2023, pages 4 to 5.

[336] Build Application, Schedule 5, Attachment 1, Attachment 4, page 4.

feasibility questions surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole."[337]

(153) Hydro did assess, to some degree, BESS resources in the 2024 RAP, including in its LIL Shortfall Analysis modeling. Specifically, Hydro found that there "may be minimal differences in the reliability contribution of a single 47.2 MW CT and a single 47.2 MW battery (four-hour or eight-hour duration)" during a "prolonged outage in the winter."[338] However, Hydro asserted that the "reliability contribution of batteries" may be "inflating" due to (1) the model's "perfect foresight within the day" of "the optimal time to charge and discharge the battery," which would not be the case in a "real-life situation," and (2) the model not accounting for "the duration of outages, which will have a significant effect on the amount of energy available in a day."[339]

(154) In our view, it would have been preferable for Hydro to include at least some capacity expansion modeling runs with BESS resources available to the model to choose. Hydro's modeling in the RAP matter allowed BESS resources to be selected in just 12 of 30 capacity expansion modeling runs.[340] Of those twelve, BESS projects were selected in five cases, including in one case in which BESS and CT resources were selected, but BDE Unit 8 was not.[341] Similarly, it would have been preferable to conduct a LIL Shortfall Analysis run with a expansion plan that included a BESS resource. Hydro's concern that certain simplifying assumptions about BESS resources are not insignificant, but we would make two counterpoints.[342] First, it is not clear to us why "the duration of outages" is a relevant factor when the scenario being modeled is a six-week outage.[343] Second, as we have noted above, the model also makes certain simplifying assumptions regarding BDE Unit 8 and the Avalon CT that may inflate their assumed reliability contribution.

(155) We also note that Hydro has made it clear that BESS resources "are emerging as a viable supply solution worthy of further consideration"[344] that are "likely to play a role on [Hydro's] system in the future as technology advancement helps to reduce the cost," though "further study is required to determine the role, sizing, and location of BESS on the system."[345] Hydro confirmed to us that it has

[337] Build Application, Schedule 1, footnote 26.
[338] 2024 RAP, Appendix C, page 56 lines 1 to 3.
[339] 2024 RAP, Appendix C, page 56 lines 8 to 12.
[340] 2024 RAP, Appendix C, Table 5; 2024 RAP, Scenario Summary Tables.
[341] 2024 RAP, Appendix C, section 6.2.1.1.7.
[342] 2024 RAP, Appendix C, page 56, lines 8 to 12.
[343] 2024 RAP, Appendix C, page 56, lines 11 and 12.
[344] Build Application, Schedule 3, footnote 26.
[345] 2024 RAP, Plan Overview, page 49 lines 17 to 19.

engaged a consultant to conduct an extensive study that considers the role of BESS resources on its system and their capacity contribution.[346] That study is expected in the third quarter of 2025.[347]

(156) Seventh, the LIL Shortfall Analysis asserts that 100 MW of rotating outages is manageable. The management of outages would largely fall to Newfoundland Power, not Hydro, and thus it would be beneficial to receive confirmation in this proceeding from Newfoundland Power confirming its confidence in the ability to successfully rotate 100 MW of outages. It is our understanding that Newfoundland Power has invested in the distribution system, which will allow better management of rotating outages.

(157) Finally, we note that the LIL Shortfall Analysis is the primary basis on which Hydro has proposed advancing the Avalon CT project to 2031.[348] We address the implications of the LIL shortfall analysis in section III below.

I. Hydro's Responses to Bates White's August 2024 Recommendations

(158) In response to the 2024 RAP filing, Bates White issued an assessment which included 63 recommendations to consider in the near term.[349] This section reviews how these items were considered by Hydro.

(159) Recommendations made by Bates White were addressed via three vehicles: technical conferences, responses to requests for information ("RFIs") following the technical conferences, or in modifying the approach to the Build Application.[350] Four technical conferences were held between September and October of 2024, after Bates White had submitted our August 2024 assessment of the 2024 RAP. These conferences were followed by RFIs, filed in November and responded to in December of 2024. Requests were submitted by Bates White and the Board, Newfoundland Power, Industrial Customers, and the Consumer Advocate.

(160) Hydro responded in some manner to all our August 2024 recommendations this process. Many of Hydro's points of discussion during those technical conferences directly and satisfactorily addressed our recommendations. In some cases, we sought additional data, which we received through RFIs

[346] Information Provided to Bates White.

[347] Information Provided to Bates White.

[348] Build Application, Schedule 1, page 15 line 23.

[349] Bates White Assessment of 2024 RRA, Attachment 2

[350] These three vehicles are not mutually exclusive – many recommendations from Bates White were responded to in both the technical conferences and RFIs, or responded to and implemented into the Build Application.

(e.g, further detail on modeling assumptions and results). In other cases, we sought clarification, which was provided either during the technical conferences or through RFI responses.

(161) The table below shows the 46 recommendations that were, in our view, fully addressed by Hydro.

Table 13: Bates White's 2024 Recommendations Fully Addressed by Hydro[351]

Item Number	Page	Section	Recommendation
(1)	4	III.B	Provide additional detail on modeling results, including energy deliveries over the LIL.
(2)	5	III.B	Include Board and other stakeholders in the consideration of reliability and cost tradeoffs.
(4)	7	III.B	Provide additional context and support for the "economic feasibility" of meeting NPCC operational reliability standards.
(5)	7	III.B	Further examine the implications of a LIL bipole outage as the largest single contingency, rather than just a single Muskrat Falls unit.
(6)	7	III.B	Further consider the extent to which the LIL shortfall analysis - peak winter, six weeks in outage duration - appropriately captures LIL bipole outage risk.
(7)	7 to 8	III.B	Vet all assumptions included in the LIL shortfall analysis, including modeled and yet-to-be-identified mitigants for accuracy and likelihood.
(8)	8	III.B	Vet all reliability criteria assumptions.
(9)	9	III.C	Provide detail on modeling assumptions, inputs and results.
(10)	13	II.C.1	Provide support for assumptions regarding firm capacity adjustments.
(11)	14	II.C.1	Provide detail on modeling assumptions and cost information for the Holyrood units through 2030.
(12)	14	II.C.1	Examine the justification for the assumed sustaining of the Holyrood unites through 2030.
(13)	14	II.C.1	Assess impacts of earlier retirement dates for one or more of the Holyrood units.
(16)	15	II.C.1	Clarify the specific expected timing of Holyrood's retirement relative to the commissioning of replacement generation.
(17)	16	II.C.1	Clarify the distinction between "near" term and long-term planning, and explain how near-term planning assumptions affect the expansion planning process, modeling, and Recommended Portfolio.
(18)	16	II.C.1	Consider sensitivity analysis in the Resource Planning Model using higher forced outage rates, especially for generating assets such as Holyrood.
(19)	16	II.C.1	Explain the interaction between the expected operation of the thermal units, the expected sustaining capital expenses to maintain those assets, and the assumed forced outage rates.
(20)	20 to 21	II.C.2	Model a broad range of bipole equivalent forced outage rates for the LIL.
(23)	24	II.D	Continue review of ECDM options and structures, and clarify how Hydro plans to incorporate learnings over time to inform potential future ECDM investments.
(24)	25	II.D	Address cost assumptions for BESS projects.
(28)	26	II.D	Provide additional information about potential tax credits, and include sensitivities to determine if these impact selected supply options.
(29)	26	II.D	Explain whether and how RICE units were evaluated as a supply option.
(30)	27	II.D	Consider directly engaging with vendors of hydrogen-compatible CTs that were not responsive to Hydro's initial queries to better assess the availability of such units.

[351] Pages and Sections in this table refer to where in Bates White Assessment of 2024 RRA where the recommendations were given.S

Item Number	Page	Section	Recommendation
(31)	27	II.D	Consider alternative fuel options for CT fuel source.
(34)	28	II.D	Explain assumed timing of potential uprates and how such projects could affect the recommended portfolio.
(36)	28	II.D	Identify how the uprate of BDE7 is impacted by the inclusion of BDE Unit 8 in the Recommended Portfolio.
(38)	29	II.D	Provide further support for the assumption of a five-year lead time for power transformers and circuit breakers.
(40)	30	II.D	Elaborate on the definition of "base-loaded" and explain if generation output is being limited, and if so explain further selection of diesel-fired generation.
(41)	30	II.D	Explain further whether existing PPAs contain any renewal rates, and the rates, terms, and conditions of these rights.
(43)	34	II.E	Further explore and justify the forced inclusion of wind resources in all sensitivity designs.
(46)	36	II.F	Provide wind profiles and support to clarify seasonal variability in wind that was modeled.
(47)	36	II.F	Provide the daily energy profiles simulated for use in the expansion and firm energy analysis models.
(48)	37	II.F	Provide additional status and details of the commercial arrangements with Hydro Quebec for energy or capacity from Muskrat Falls.
(49)	37	II.F	Provide detail regarding transmission losses assumptions and results, hydro spillage, and wind curtailments for its model runs.
(50)	37	II.F	Clarify that off-peak deliveries of energy to NSPI ("Supplemental Energy") were not modeled.
(51)	37	II.F	Explain how obligations under the Energy Access Agreement with Nova Scotia were modeled.
(52)	38	II.F	Provide additional detail about export arrangements.
(53)	38	II.F	Provide further reasoning for the 2032 representative year being selected.
(54)	38	II.F	Provide full results of Firm Energy Analysis and explain implications beyond 2034.
(55)	40	II.G.1	Clarify why the addition of wind in the lowest cost portfolios is later than in other portfolios, and confirm wind resource needs in 2030.
(56)	41	II.G.1	Clarify whether BESS projects would be selected over a CT when CT costs are assumed to be higher than baseline.
(57)	43	II.G.1	Specify the NPV of the 4AEF(ADV) project and the cost of moving the CT addition up to 2031.
(59)	45	II.G.2	Vet and provide further details behind the recommended portfolio not meeting the reliability requirements of the reference case, not meeting the energy needs in the IIS load forecast, and the threat of prolonged LIL forced outage.
(60)	45	II.G.3	Explain any near-term commitments and/or expenditures with respect to the proposed CT and BDE Unit 8, prior to regulatory review and approval.
(61)	46	II.G.3	Provide detail on the planned timing for the FEED studies and clarify if these studies will resolve questions regarding the burn-off requirement.
(62)	46	II.G.3	Explain how cost recovery will be pursued and how risks will be managed.
(63)	46	II.G.3	Explain how Hydro will track and act on material changes in the supply and demand landscape that may affect the optimality of the recommended portfolio.

(162) The next table shows the three recommendations that have been satisfactorily addressed by Hydro, but for which substantial work is to follow. That is, Hydro has taken reasonable steps to date, but much of the work must be done and can only be done in future matters. For example, Hydro has committed to perform additional model runs with a 0.1 LOLE resource adequacy standard

(Recommendation 3) and pursue incorporation of the firm energy analysis within its capacity expansion model (Recommendation 45) in its 2026 reliability and resource adequacy filing.[352]

Table 14: Bates White's 2024 Recommendations satisfactorily addressed by Hydro, with material work remaining[353]

Item Number	Page	Section	Recommendation
(3)	5	III.B	Perform additional model runs with a 0.1 LOLE standard.
(22)	22	II.C.2	Continue to address all Haldar recommendations and update the RAP process with findings.
(45)	36	II.F	Consider incorporating firm energy analysis process into the PLEXOS model.

(163) The last table identifies the remaining 14 recommendations for which Hydro has been at least partially responsive, but for which we wish to highlight additional work needed or context for consideration.

Table 15: Bates White's 2024 Recommendations at least partially addressed by Hydro[354]

Item Number	Page	Section	Recommendation
(14)	15	II.C.1	Justify the assumption that "any new supply would be seven to ten years away from the date of applications for [regulatory] approval" as stated on page 65, lines 12-13 of the RAP Filing.
(15)	15	II.C.1	Consider the possibility Holyrood remains an asset beyond 2030, and model the costs and impacts of retaining one or all of the Holyrood units.
(21)	21	II.C.2	Assess projected cost and benefits of all investments made to improve LIL performance.
(25)	25	II.D	Evaluate CT capital cost estimates for accuracy and reasonableness relative to market.
(26)	25	II.D	Provide backup for CT cost estimates and consider Daymark's feedback on the cost assumptions of these units.
(27)	26	II.D	Consider additional sensitivities in which hydro costs are in excess of those estimated and modeled.
(32)	28	II.D	Explain how logistical challenges of fuel supply will be addressed and comment on additional costs associated with maintaining fuel supply reliability.
(33)	28	II.D	Consider the possibility of a competitive solicitation for a turnkey CT solution.
(35)	28	II.D	Address whether the scheduling of hydroelectric generation or water release from the 32 hydroelectric facilities on the IIS would offer an economic long-term storage option.
(37)	29	II.D	Consider 6- and 8-hour duration BESS projects.
(39)	30	II.D	Provide additional backup for ELCC figures utilized and consider the dynamic nature of ELCC calculations in the procurement process.

352 Information Provided to Bates White.

353 Pages and Sections in this table refer to where in Bates White Assessment of 2024 RRA where the recommendations were given.S

354 Pages and Sections in this table refer to where in Bates White Assessment of 2024 RRA where the recommendations were given.S

Item Number	Page	Section	Recommendation
(42)	30	II.D	Consider the pursuit of competitive solicitation for energy and capacity, including offers from parties in other provinces, allowing for direct comparison to utility self-build options.
(44)	34	II.E	Further review and justify the annual fuel burn-off assumption which provides the need for sensitivity AC.
(58)	43	II.G.1	Consider providing a LIL Shortfall Analysis assessment of a portfolio that included BESS.

(164) We address each of these 14 recommendations as follows:

- We have included recommendations in this report that request Hydro conduct additional modeling, which, if done, will address many of the items identified in the table above. These include assessment of delays in the schedule of BDE Unit 8 or the Avalon CT (Recommendation 14), delay in the retirement of Holyrood TGS (Recommendation 15), higher capital cost cases (Recommendations 25, 26, 27), and further consideration of BESS resources (Recommendations 37, 43).

- Other recommendations in the table identify important steps Hydro should take in both the near and longer term. As we note in section III.D.iii above, we reiterate our August 2024 recommendation (Recommendation 21) that Hydro understand and compare the expected costs and benefits of LIL investments so as to allow Hydro, stakeholders, and the Board to better allocate ratepayer dollars to projects that deliver the highest net benefits.

- Similarly, Hydro has provided limited commitment to consider competitive solicitation for a turnkey CT solution (Recommendation 33) and more generally for energy and capacity, including offers from parties in other provinces, allowing for direct comparison to Hydro's self-build option (Recommendation 42). Hydro has noted that despite "active discussion with proponents," there is "no immediate opportunity" for turnkey capacity, and has noted its "economies of scale, existing infrastructure and required expertise to support CT ownership and operation."[355] Hydro has also pointed to its planned wind Expression of Interest as evidence of the use of competition to procure new resources.[356] It may be that Hydro is best suited to offer the best rates, terms, and conditions to develop and own new energy and capacity resources; competitive solicitations help provide evidentiary support for such an assertion, as Hydro would be able to review *binding* offers from third parties for such services to compare with Hydro's own capabilities. We reiterate our recommendation for Hydro to consider employing competitive solicitation for its energy and capacity needs.

[355] Hydro, "2024 Resource Adequacy Plan Technical Conference #2 Issue #4: Resource Supply Options," October 2, 2024, slide 22.

[356] Hydro, "2024 Resource Adequacy Plan Technical Conference #2 Issue #4: Resource Supply Options," October 2, 2024, slide 51.

- Some of the recommendations in the table above highlight key risk areas associated with Hydro's planned investments that will require Hydro to develop rigorous, effective plans to prevent inefficient, costly outcomes for ratepayers. Hydro's simplified modeling assumptions for fuel supply (Recommendation 32), hydrological resources (Recommendation 35), and fuel burn-off requirements (Recommendation 44) identify the risks and costs inherent in the operation of BDE Unit 8 and the Avalon CT. Should the Build Application be approved, Hydro should be focused on developing fuel supply and water management plans that keep these resources reliable. And given the substantial cost of the requirement to burn-off fuel annually (explained in Section E), Hydro should also develop solutions or mitigations to eliminate or minimize the need to burn-off fuel at the Avalon CT.

- The remaining recommendation (Recommendation 39) is to be addressed through an ELCC update study due sometime in 2025.[357] While useful, the timing of the study matters. A key issue related to BESS resources, in particular, is the assumed ELCC. When ELCCs are 60% or higher (a reasonable assumption), BESS resources were selected in Hydro's capacity expansion modeling.[358] An updated ELCC study could provide additional insight regarding a more precise assumption for BESS ELCCs. The same would be true for other resources, including solar and wind.

J. Assessment of Build Application's Consistency with "Settled Issues"

(165) In our view, the Build Application's content appears consistent with the eleven "Settled Issues" identified in the RAP Settlement Agreement.[359] We observed no evidence from the Build Application that impacts any of the Settled Issues.

(166) Elsewhere in our report, we identify shortcomings of Hydro's capacity expansion modeling conducted in support of the Build Application, but these criticisms do not suggest Hydro has failed to consider the Settled Issues in its Build Application. For example, the eighth Settled Issue reads: "Hydro analyzed an appropriate range of scenarios and sensitivities for the analysis included in the Resource Adequacy Plan to determine its recommendations regarding the minimum investment required being Bay d'Espoir Unit 8 and the Avalon CT."[360] We have recommended that Hydro conduct additional modeling to further support the Build Application. However, this

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[357] Hydro, "2024 Resource Adequacy Plan Technical Conference #2 Issue #4: Resource Supply Options," October 2, 2024, slide 37.

[358] *See, for example*: Hydro, "2024 Resource Adequacy Plan Technical Conference #4: Expansion Plan, Insights and Next Steps," October 29, 2024, slides 24 to 25.

[359] Build Application, Schedule 2, Attachment 1, pages 6 to 7.

[360] Build Application, Schedule 2, Attachment 1, page 6.

recommendation, which critiques Hydro's modeling in support of the Build Application, does not suggest that the "scenarios and sensitivities" conducted for the 2024 RAP were not appropriate. Rather, our recommendation is focused on the modeling done in support of the Build Application, which was not prejudged or anticipated by the RAP Settlement Agreement.

IV. Assessment of Modeling Results and Recommended Resource Additions

(167) In this section, we review the results of Hydro's capacity expansion and LIL Shortfall Analysis modeling that was put forth in support of the Build Application.

A. Expansion Plan Results and Recommended Portfolio

i. Summary of Expansion Plan, Build Application requests

(168) Hydro's proposed expansion plan is shown in the following table. The plan includes building BDE Unit 8 by 2031 and building the Avalon CT by 2031 to meet firm capacity requirements and procuring "up to" 400 MW of new wind generation by 2034 to meet firm energy requirements.[361]

Table 16: Recommended Expansion Plan[362]

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
Avalon CT	141.6	0		1	1	1	1
Wind 100 MW	22	350	1	3	3	3	4
Firm Capacity (MW)			**22**	**362**	**362**	**362**	**384**
Firm Energy (GWh)			**350**	**1050**	**1050**	**1050**	**1400**

(169) Hydro has put forth a request for approval of two components of the recommended expansion plan—that is, $1.08 billion for BDE Unit 8 and $891 million for the Avalon CT. The costs sought by Hydro are not hard, not-to-exceed budget caps, but rather authorized budgets based on current Class 3 estimates at a P85 confidence level (subject to the discussion above regarding the development of the cost estimates for BDE Unit 8 and the Avalon CT).[363] The Build Application does not seek approval for any wind generation or transmission investments.[364]

ii. Hydro has demonstrated a need for firm capacity by 2035, assuming Holyrood TGS and other thermal generators are retired

(170) Hydro has, in our view, successfully demonstrated that there is a need for firm capacity by 2035, assuming the concurrent retirement of the Holyrood TGS, Stephenville GT, and Hardwoods GT. As noted earlier in this report, Hydro has used its most conservative load forecast (Slow

[361] Build Application, Schedule 1, page 17 lines 4 to 7.

[362] Build Application, Schedule 3, Table 1.

[363] Build Application, Schedule 1, page 20 line 1.

[364] Build Application, Application, paragraph 22.

Decarbonization) and most aggressive LIL equivalent forced outage rate (1%) to identify the "minimum investment" needed to meet its selected planning criterion of 2.8 LOLH. Hydro's capacity expansion modeling (Scenario 4AEF) shows a need for firm capacity by 2035, with some of that capacity online by 2031. This is shown in the table below.

Table 17: Scenario 4AEF Capacity Expansion Modeling Results[365]

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
Avalon CT	141.6	0						1
Wind	22	350	1	3	3	4	4	4
Firm Capacity (MW)			**22**	**220**	**220**	**242**	**242**	**384**
Firm Energy (GWh)			**350**	**1050**	**1050**	**1400**	**1400**	**1400**

(171) The results in Table 17 above should not be interpreted to necessarily suggest that Hydro needs exactly (or at least) 384 MW of firm capacity by 2035. Rather, this is the amount of firm capacity built by the model to meet resource planning criteria, given the supply options from which the model can choose. Both BDE 8 and the Avalon CT are approximately 150 MW in size, and thus the selection of these two resources in combination with firm capacity provided by wind generation could produce some surplus. Evidence of such a surplus is included in the 2024 RAP: in Scenario 4AB80, which uses the Slow Decarbonization load forecast and a 1% LIL bipole forced outage rate, the model meets resource planning criteria by building 282 MW of firm capacity by 2034.[366] (The 2035 results for this case are not shown in the referenced table in the 2024 RAP.)

(172) The results in Table 17 are contingent on the retirement of 618 MW of existing thermal generation, particularly Holyrood TGS, which currently provides 490 MW of capacity.[367] *Absent these retirements, there is no demonstrated need for this level of new capacity*.[368] This is a point that must be underscored. Hydro's capacity expansion modeling assumes in 100% of cases that these thermal assets (including Holyrood TGS) are retired in 2030. Should these retirements be delayed, Hydro's modeling suggests that the system would have excess capacity.

(173) The adequacy of these investments to meet capacity needs in 2031 and beyond are also dependent on the performance of the LIL. Hydro has assumed a 1% LIL equivalent forced outage rate in its key Scenario (4AEF), which is the best achievable equivalent forced outage rate, even given ongoing remedial work on which Hydro is currently engaged.[369] Should the LIL underperform, Hydro's

[365] Build Application, Schedule 3, Table 5.

[366] 2024 RAP, Appendix C, Table 23.

[367] 2024 RAP, Appendix B, Table 8.

[368] This statement presumes the thermal generation (including Holyrood TGS) would be maintained as reliable sources of capacity beyond 2030.

[369] 2024 RAP Technical Conference #1, slide 53.

necessary planning reserve margin to maintain a 2.8 LOLH resource planning criterion would increase, bringing with it additional capacity investment and ratepayer costs. The adequacy of the requested investments is also conditional on firm capacity provided by new wind generation resources, which were expected to total 88 MW in firm capacity contribution by 2033.

iii. The optimal timing of the investments in new capacity depends on LIL Shortfall Analysis results

(174) Hydro's capacity expansion modeling also demonstrates that the optimal timing of the firm capacity additions is 2031 (for one resource) and 2035 (for the other). There is not a demonstrable need for *both* projects in 2031, as evidenced by Hydro's capacity expansion modeling runs. The Scenario 4 model runs, which are the basis for Hydro's Minimum Investment Required Expansion Plan and related requested investments in the Build Application, select a firm capacity resource in 2031 and a second in 2035 in 100% of all sensitivity model runs.[370]

(175) Hydro, however, is proposing that both firm capacity resources would have in-service dates in 2031.[371] One reason for the advancement of one of the firm capacity resources to 2031 (to match the other) is the results of the LIL Shortfall Analysis.[372] Again, Hydro's LIL Shortfall Analysis was run, in "Combination 1," with the Slow Decarbonization load forecast and the Minimum Investment Required Expansion Plan, as optimized by Hydro's capacity expansion modeling. Then, Hydro ran the LIL Shortfall Analysis using "Combination 2," which matched Combination 1, except both BDE Unit 8 and the Avalon CT would be online in 2031.[373] The results of these two runs demonstrate the benefits of building both firm capacity resources in time for a 2031 in-service date. The following two tables compare the LIL Shortfall Analysis results of Combination 1 and Combination 2, assuming the P50 severity case and P90 severity case, respectively. In both cases, Combination 2, which advances the in-service date of a firm capacity resource to 2031 (4AEF(ADV)), materially outperforms Combination 1.

[370] Build Application, Schedule 3, section 5.2.2.1.
[371] Build Application, Schedule 3, page 4 lines 23 to 24.
[372] Build Application, Schedule 3, page 38 lines 7 to 11.
[373] Build Application, Schedule 3, page 38 lines 14 to 18.

Table 18: Comparison of LIL Shortfall Results (P50 case)[374]

	Combination 1	Combination 2
Load Forecast Scenario	Slow Decarbonization	Slow Decarbonization
Expansion Plan Scenario	4AEF	4AEF (ADV)
Hours of shortfall	142	24
Total energy shortfall (GWh)	10	1
Peak shortfall (MW)	256	124
% of time shortfall > 100 MW	4.0%	0.1%

Table 19: Comparison of LIL Shortfall Results (P90 case)[375]

	Combination 1	Combination 2
Load Forecast Scenario	Slow Decarbonization	Slow Decarbonization
Expansion Plan Scenario	4AEF	4AEF (ADV)
Hours of shortfall	351	102
Total energy shortfall (GWh)	35	7
Peak shortfall (MW)	358	232
% of time shortfall > 100 MW	14.0%	3.0%

(176) The advancement of both resources to have in-service dates in 2031 acts as a form of insurance against an extended LIL bipole outage during peak season. The incremental cost of this insurance (i.e., advancing one firm capacity resource to match the other's in-service date of 2031) is approximately $0.2 billion on an NPV basis, according to Hydro's modeling.[376]

(177) Much, then, rides on the outputs of the LIL Shortfall Analysis. Here, we wish to reiterate the concerns and/or key assumptions we raised above regarding the LIL Shortfall Analysis:

- As with the capacity expansion modeling, the LIL Shortfall Analysis modeling assumes 618 MW of existing thermal generation is retired. Should retirement of some or all of that thermal generation not occur, Hydro's modeling fails to demonstrate that additional capacity is needed to meet Hydro's stated criteria of a 2.8 LOLH and no more than 100 MW of rotating outages. And as noted earlier in this report, the three proposed conditions that must be met in order to retire the thermal generation is non-trivial and could fail to be met, even if both BDE Unit 8 and the Avalon CT are built by 2031.

- The LIL Shortfall Analysis may overstate the reliability contribution of BDE Unit 8 during an extended bipole outage of the LIL. As we explain earlier in this report, the LIL Shortfall Analysis results assume output that is 34 percent higher than the *highest* six-week output from the collective plant since 2015; moreover, due to potential hydrological constraints, it is

[374] Build Application, Schedule 3, page 48 Table 9.

[375] Build Application, Schedule 3, Table 10.

[376] Build Application, Schedule 3, page 51 lines 8 to 9.

not clear from the data that the collective plant can produce the level of output assumed in the analysis. Even assuming that the Bay d'Espoir facility would have sufficient water resources to achieve the six-week output modeled in the LIL Shortfall Analysis, it would seem likely that at the end of the outage, Bay d'Espoir's hydrological resources would be exhausted and in need of replenishment. This takes time, and as storage levels are restored, it is possible that the plant would be derated (due to limited water), which could cause resource adequacy and reliability issues on the system that are not captured in the LIL Shortfall Analysis results.

- The LIL Shortfall Analysis does not consider transmission constraints, including current constraints that prevent full transfer of all output from Bay d'Espoir (including BDE Unit 8) to the Avalon during a LIL bipole outage. As proposed, therefore, the deliverability of BDE Unit 8 is in question during a LIL bipole outage; Hydro is currently studying its options.

- The LIL Shortfall Analysis assumes no constraints associated with fueling the Avalon CT, which may be an aggressive assumption. If the Avalon CT is less efficient than modeled, or the LIL bipole outage lasts longer, or the unit is operated at a higher capacity factor than assumed, Hydro may need to refuel the Avalon CT during the outage. Moreover, Hydro has taken the simplifying assumption that "sufficient fuel is available when required,"[377] though its consultant identified the risk that "[f]uel suppliers may be unable to provide sufficient fuel supply" as an "active" risk that "could result in insufficient fuel supply, or additional fuel costs."[378]

- The LIL Shortfall Analysis does not assess the efficacy or value of BESS resources. The LIL Shortfall Analysis conducted for the Build Application did not model BESS resources in any modeled expansion plan. The 2024 RAP did review BESS contributions to reliability during a LIL bipole outage, which found a single 47.2 MW BESS resource to be about equal to that of a CT. Hydro instead relied on assertions that BESS resource contributions to reliability in this case was likely overstated that the "reliability contribution of batteries" may be "inflating" due to (1) the model's "perfect foresight within the day" of "the optimal time to charge and discharge the battery," which would not be the case in a "real-life situation," and (2) the model not accounting for "the duration of outages, which will have a significant effect on the amount of energy available in a day."[379]

(178) Taken as a whole, concerns about the LIL Shortfall Analysis suggest that, to increase confidence in the decision to incur an estimated $200 million in additional costs to build both firm capacity

[377] NP-NLH-104(c).

[378] Build Application, Schedule 5, Attachment 1, page 4.

[379] 2024 RAP, Appendix C, page 56 lines 1 to 12.

resources by 2031, Hydro could supplement its Build Application with additional LIL Shortfall Modeling. We address this point below.

iv. The selection of the Avalon CT is better supported, while BDE Unit 8 carries with it certain risks and costs that were not fully considered in Hydro's modeling or vetted against potential alternatives

(179) Hydro's capacity expansion modeling identifies BDE Unit 8 as the optimal resource to build first (in 2031); the Avalon CT is the next best resource, being selected alongside BDE Unit 8, but built later (in 2035).[380] Based on our review to date, it is the Avalon CT that has been shown to be better supported by evidence in the Build Application, not BDE Unit 8. We draw this conclusion based on several observations.

(180) First, the cost differences between the two resources (BDE Unit 8 and the Avalon CT) are minimal. On a capital cost ($/kW) basis, the Avalon CT ([redacted]/kW) is actually a less expensive unit than BDE Unit 8 ([redacted]/kW).[381] However, because BDE Unit 8 is assumed to have a much longer economic life (60 years) than the Avalon CT (35 years), the difference in annualized build cost is reduced, though the Avalon CT remains the lower cost unit on a capital cost basis. This is shown in the table below, which compares the annualized bid cost of both resources, assuming different in-service years (the bolded year (2031) matches the Build Application proposal). Differences in operating costs, especially fuel costs, and fixed O&M costs are lower for BDE Unit 8 than the Avalon CT, impacting the capacity expansion results.

[380] Build Application, Schedule 3, section 5.2.2.1.

[381] Information Provided to Bates White.

Table 20: Comparison of BDE Unit 8, Avalon CT annualized build cost (2030-2040) ($mm) [382]

Year Built	Annualized Build Cost ($M)	
	BDE Unit 8	Avalon CT
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

(181) Second, there was some concern raised in the 2024 RAP that the estimate for BDE Unit 8 (and other new hydroelectric resource options) may be optimistically low. Both Hydro's consultant (Daymark) and Bates White raised this issue.[383] Hydro partially addressed these concerns by conducting a specific sensitivity (AD), which modeled hydro capital costs that were 50% higher than its base case assumption. In that case (Scenario 4AD), BDE Unit 8 went unselected.[384] We noted that an even higher hydro cost sensitivity model run may be warranted to increase confidence in the overall results.[385]

(182) Third, the Avalon CT is located in a more advantageous position on the IIS than BDE Unit 8. Specifically, it is located on the Avalon Peninsula, inside the BDE-SOP 230 kV system which is constrained in normal operations to avoid thermal overload violations, and further constrained during LIL bipole outages. Moreover, the impact of the BDE-SOP 230 kV constraint prevents the transfer of the full incremental output of BDE Unit 8 to the Avalon Peninsula during normal conditions and prevents *any* transfer of incremental output of BDE Unit 8 to the Avalon Peninsula during a LIL bipole outage (when its output would be needed most). Hydro plans to address this transmission constraint but has not put forth a solution and notes that it continues to study potential solutions.

(183) Fourth, BDE Unit 8 appears to be hydrologically constrained, thereby preventing collective output from Bay d'Espoir that reflects the incremental output capability of BDE Unit 8. We explain this issue earlier in our report.

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[382] Information Provided to Bates White.

[383] Bates White Assessment of 2024 RRA, pages 25 to 26.

[384] 2024 RAP, Appendix C, section 6.2.2.1.6.

[385] Bates White Assessment of 2024 RRA, pages 34 to 35.

(184) Fifth, the Avalon CT carries with it a shorter development schedule. Consider, for example, that Hydro has put forth an "anticipated completion" date of 2029 for the Avalon CT (despite its "advanced" modeled in-service date of 2031); BDE Unit 8, on the other hand, has an anticipated completion date in 2031.[386] The Avalon CT's milestone schedule demonstrates its advantages: for example, the Avalon CT's on-site construction can begin in 2026, versus BDE Unit 8, which does not begin until 2028 in order to allow for engineering, procurement, and construction planning activities.[387]

(185) On this point, we should note that the date that the Avalon CT is to reach commercial operations has evolved considerably. In the 2024 RAP, Hydro's capacity expansion modeling for Scenario 4AEF called for the building of the Avalon CT in 2034.[388] The LIL Shortfall Analysis demonstrated additional benefits of advancing the Avalon CT to a 2031 in-service date,[389] and thus Hydro recommended an expansion plan that brought the Avalon CT in 2031.[390] Here, in the Build Application and for the first time, Hydro proposes an in-service date of 2029 for the Avalon CT.[391] None of Hydro's modeling includes an instance where the Avalon CT is online in 2029.

(186) We recognize that Hydro has taken considerable efforts in developing the Build Application and in conducting the 2024 RAP. We also note, however, that the Board is being asked to approve close to $2 billion to be charged to ratepayers at a time when ratepayers continue to pay down the final cost of the Muskrat Fall Generating Station and associated transmission assets of about $13.5 billion.[392] Additional support from Hydro would be helpful in assisting the Board to make a determination.

v. To help address the shortcomings in the Build Application, Hydro could conduct supplement modeling

(187) We offer in this section a set of recommended supplementary enhancements to the filed Application that would address the shortcomings we identify above. We recommend Hydro conduct additional modeling as follows:

- Hydro should conduct capacity expansion model runs relaxing the constraints around the CT, including both the 150 MW limit and the 150 MW "blocks" modeled, to allow for smaller, 50 MW blocks.

[386] Build Application, Application, paragraphs 13 to 14.
[387] Build Application, Overview, page 5.
[388] 2024 RAP, Appendix C, Table 32.
[389] 2024 RAP, Appendix C, section 7.2.
[390] 2024 RAP, Appendix C, Table 54.
[391] Build Application, Application, paragraph 14.
[392] Ashley Fitzpatrick, "Muskrat Falls and the price of failure," *Atlantic Business Magazine*, May 29, 2024, available at: https://atlanticbusinessmagazine.ca/web-exclusives/muskrat-falls-and-the-price-of-failure/.

- Hydro should conduct capacity expansion model runs that include BESS resources of 4-hour and 8-hour duration, assuming 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 8 and the Avalon CT.
    - Collectively, then, we recommend three additional capacity expansion model runs. In each run, Hydro should address the recommendations in the prior two bullets. That is, each run should relax the CT constraints and BESS prohibition, but should be conducted across Scenarios 4AEF, 4AEFC, and 4AEFDH.
- Hydro should conduct one 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. If no BESS resources are selected in that model run, this additional LIL Shortfall Analysis run would be unnecessary.
- Hydro should conduct one LIL Shortfall Analysis run that limits the output of Bay d'Espoir to match hydrological resource constraints identified in section III.J. 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 Peninsula in all hours.
- Hydro should 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.
    - Collectively, then, we recommend three additional LIL Shortfall Analysis runs.

V. Bates White's Recommendations

(188) In recognition of our findings and conclusions, we offer the following recommendations:

(1) Hydro should address and reconcile the potential modeling inconsistency regarding the resource selection identified by NLH under Scenario 4AEFC.

(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.

(3) Hydro should conduct capacity expansion model runs that include BESS resources of 4-hour and 8-hour duration, assuming 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 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 CT constraints and BESS prohibition and should be conducted across the three Scenarios identified in Recommendation 3.

(4) Hydro should conduct one 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 Bay d'Espoir to match potential hydrological resource constraints identified in section III.J. 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 TGS, Stephenville GT, and Hardwoods GT are not retired, the Avalon CT is in service, and BDE 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.

Vincent Musco	June 24, 2025
	Date

Collin Cain	June 24, 2025
	Date

Appendix A. *Curriculum Vitae* of Mr. Musco

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VINCENT MUSCO, MA

Partner

AREAS OF EXPERTISE

- **Electricity markets**
- **Electricity industry policy**
- **US RTOs and ISOs**
- **Resource procurement**
- **Independent Evaluator Services**
- **Integrated Resource Planning**
- **Utility Auditing**

SUMMARY OF EXPERIENCE

Vincent Musco provides expertise in electric industry policy, electric utility resource procurement, market design, market monitoring, and market operations. He has served as an expert witness and provided expert testimony on a variety of energy market and ISO/RTO issues, such as pricing in organized electricity markets, the economics of fuel and power purchases by utilities, FERC open access transmission issues, and electric utility costs and revenue requirements. Mr. Musco has consulted on issues related to market design and operations, economic, antitrust, environmental, and regulatory policy across North America (including in Hawaii, Maryland, Ohio, Oregon, Nebraska, Massachusetts, Texas, New Jersey, Mississippi, Oklahoma, New Mexico, Washington, and Maine), Alberta, Quebec, Nova Scotia, New Brunswick, Newfoundland and Labrador, and Puerto Rico, as well as for FERC and NERC. Mr. Musco has published articles in *Electricity Journal*, *Public Utilities Fortnightly*, and *IAEE Energy Forum*, and has been a frequent speaker at industry events including those sponsored by EUCI, George Washington University, Public Utility Research Center (PURC), and Platts.

EDUCATION

- MA, Economics, American University
- BS, Economics (with distinction), James Madison University

TESTIFYING EXPERIENCE

- On behalf of the Nova Scotia Utility and Review Board, provided written testimony in the matter of an appeal by Nova Scotia Power, Inc. under s.48 of the Renewable Electricity Regulations of the Minister’s Decision directing a penalty of $10 million (Matter M11150)
- On behalf of the Nova Scotia Utility and Review Board, provided written and oral testimony (with co-authors) concerning the 2024 Fuel Adjustment Mechanism Audit of Nova Scotia Power, Inc. (Matter M11533)
- On behalf of the Mississippi Public Service Commission, provided direct testimony and a recommendation on the results of the Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement (October 1, 2023–September 30, 2024)

- On behalf of the Nova Scotia Utility and Review Board, provided written testimony in the matter of an application by Port Hawkesbury Paper LP seeking confirmation it will not be responsible for repayment of costs related to Nova Scotia Power Incorporated's $500 million regulatory asset as part of the tolls, rates, and charges PHP pays to NS Power (Matter M12004)
- On behalf of the Nova Scotia Utility and Review Board, provided written testimony in the matter of an application by Four Municipal Electric Utilities for Approval to Amend the Approved Flow-Through Formulas in their Schedule of Rates for Electric Supply and Services (Matter M11893)
- On behalf of the Nebraska Public Service Commission, provided oral testimony concerning a prudence review of purchasing strategy and approach to natural gas procurement and hedging by Northwestern Energy Public Service Corporation d/b/a NorthWestern Energy (Nebraska Public Service Commission, Application No. NG-115.1)
- On behalf of the Mississippi Public Service Commission, provided direct testimony and a recommendation on the results of the Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement (October 1, 2022–September 30, 2023)
- On behalf of the Nebraska Public Service Commission, provided oral testimony concerning a prudence review of purchasing strategy and approach to natural gas procurement and hedging by Black Hills Nebraska Gas, LLC d/b/a Black Hills Energy (Nebraska Public Service Commission, Application No. NG-119)
- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony (with co-authors) concerning the 2022 Fuel Adjustment Mechanism Audit of Nova Scotia Power, Inc. (Matter M10416)
- On behalf of the Commonwealth of Massachusetts Office of Attorney General, provided written joint and oral testimony concerning the request of NSTAR Electric Company d/b/a Eversource Energy and Eversource Gas Company of Massachusetts d/b/a Eversource Energy of approval to develop, construct, own, and operate respective solar photovoltaic facilities paired with battery energy storage (Massachusetts Department of Public Utilities, Docket Nos. D.P.U. 22-64, D.P.U. 22-65)
- On behalf of the Nova Scotia Utility and Review Board, provided written testimony and reply testimony in the matter of Nova Scotia Power, Inc.'s Extra Large Industrial Active Demand Control Tariff (Matter M11021)
- On behalf of the New Brunswick Energy and Utilities Board, provided an expert report and oral testimony in the matter of New Brunswick Power Corporation FY 2023/2024 General Rate Application (NBEUB Matter No. 0541)
- On behalf of the Mississippi Public Service Commission, provided direct testimony and a recommendation on the results of the Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement (October 1, 2021–September 30, 2022)
- On behalf of the Commonwealth of Massachusetts Office of Attorney General, provided written testimony concerning the request of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company d/b/a Eversource Energy, and Fitchburg Gas and Electric Light Company d/b/a Unitil of approval of six purchase power agreements for offshore wind and the competitive procurement process (Massachusetts Department of Public Utilities, Docket Nos. D.P.U. 22-70, D.P.U. 22-71, D.P.U. 22-72)
- On behalf of the Nova Scotia Utility and Review Board, provided written and oral testimony in the matter of an application by Nova Scotia Power, Inc. for approval of certain revisions to its rates, charges, and regulations (Matter M10431)

- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony in the matter of an application by Nova Scotia Power Maritime Link, Inc. for approval of project capital costs for the Maritime Link transmission project (Matter M10206)
- On behalf of the Nova Scotia Utility and Review Board, provided written testimony in the matter of an application by Nova Scotia Power, Inc. for an exemption from the requirements of the Affiliate Code of Conduct to permit additional purchases from the Brooklyn Energy biomass facility (Matter M09880)
- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony (with co-authors) concerning the 2020 Fuel Adjustment Mechanism Audit of Nova Scotia Power, Inc. (Matter M09548)
- On behalf of the Nova Scotia Utility and Review Board, provided oral testimony (with co-author) concerning the Application by Nova Scotia Power Maritime Link Incorporated for Approval of the 2021 Interim Cost Assessment (Matter M09810)
- On behalf of the Commonwealth of Massachusetts Office of Attorney General, provided oral and written testimony concerning the request of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company d/b/a Eversource Energy, and Fitchburg Gas and Electric Light Company d/b/a Unitil of approval of six purchase power agreements for offshore wind, the competitive procurement process, and the utilities' request for remuneration payments (Massachusetts Department of Public Utilities, Docket Nos. D.P.U. 20-16, D.P.U. 20-17, D.P.U. 20-18)
- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony (with co-author) concerning the Application by Nova Scotia Power Maritime Link Incorporated for Approval of the 2020 Interim Cost Assessment (Matter M09277)
- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony (with co-authors) concerning the Application by Nova Scotia Power, Inc. for Approval of its 2020-2022 Fuel Stability Plan (Matter M09288)
- On behalf of the Nova Scotia Utility and Review Board, provided oral and written testimony (with co-authors) concerning the 2018 Fuel Adjustment Mechanism Audit of Nova Scotia Power, Inc. (Matter M08195)
- On behalf of the Commonwealth of Massachusetts Office of Attorney General, provided oral and written testimony concerning the request of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company d/b/a Eversource Energy, and Fitchburg Gas and Electric Light Company d/b/a Unitil for remuneration payments under clean energy power purchase agreements and transmission service agreements (Massachusetts Department of Public Utilities, Docket Nos. D.P.U. 18-64, D.P.U. 18-65, D.P.U. 18-66)
- On behalf of the Commonwealth of Massachusetts Office of Attorney General, provided oral and written testimony concerning the request of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company d/b/a Eversource Energy, and Fitchburg Gas and Electric Light Company d/b/a Unitil for remuneration payments under six offshore wind power purchase agreements (Massachusetts Department of Public Utilities, Docket Nos. D.P.U. 18-76, D.P.U. 18-77, D.P.U. 18-78)
- On behalf of Newfoundland and Labrador Hydro and Nalcor Energy Marketing Corporation, provided testimony concerning Hydro-Québec TransÉnergie's acceptance of capacity e-tags for reserve scheduling. (Régie de l'énergie, No. P-130-004)

- On behalf of the Mississippi Public Service Commission, provided direct testimony and a recommendation on the results of the Independent Auditor's Report on the Annual Management Review Audit of Entergy Mississippi, Inc. (October 1, 2012–September 30, 2014)
- On behalf of the Mississippi Public Service Commission, gave direct testimony and a recommendation to the Mississippi Public Service Commission on the results of the Independent Auditor's Report on the Annual Management Review Audit of Entergy Mississippi, Inc.
- On behalf of TransCanada Energy Ltd., provided direct and rebuttal evidence and oral testimony concerning the Alberta Electric System Operator's approach to allocating transmission import capability. (Alberta Utilities Commission, Proceeding 1633)
- On behalf of Capital Power Corporation, TransCanada Energy Ltd., and TransAlta Corporation, provided direct evidence and oral testimony concerning Milner Power Inc.'s Transmission Loss Factor Rule and Loss Factor Methodology Complaint. (Alberta Utilities Commission, Application No. 1606494)

CONSULTING REPORTS

- Submission regarding Nova Scotia Power, Inc.'s Extension Application for the Extra Large Industrial Active Demand Control Tariff. For the Nova Scotia Energy Board (June 2025).
- Comments regarding Nova Scotia Power, Inc.'s Extra Large Industrial Active Demand Control (ELIADC) Tariff – 2024 Annual Report. For the Nova Scotia Energy Board (May 2025).
- Initial Comments on the Summer 2024 Through Spring 2025 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2025).
- Initial Comments on the Summer 2024 Through Spring 2025 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2025).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2025 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (May 2025).
- Pre-Bid Report of the Independent Observer for the Hawaiian Electric Companies' Integrated Grid Planning Request for Proposals for Renewable Dispatchable Generation and Energy Storage on O`ahu and Hawai`i Island. For the Hawaii Public Utilities Commission (April 2025).
- Integrated Resource Plan Request for Proposals Design Considerations in Light of Lessons Learned from Stage 3 Requests for Proposals (Independent Observer Comments). For the Hawaii Public Utilities Commission (April 2025).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2025 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2025).
- The Independent Evaluator's Report Regarding Public Service Company of New Mexico's Request for Proposals for Firm Capacity Resources with Guaranteed Commercial Operation Dates of April 1, 2028 or Earlier. Presented to the New Mexico Public Regulation Commission. (December 2024).
- Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement. For the Mississippi Public Service Commission (December 2024).

- Post-Bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2024 Procurement of Indexed Renewable Energy Credits from Wind, Solar, Brownfield, and Hydropower Resources. For the Illinois Commerce Commission (December 2024).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2024 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2024).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2024 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2024).
- Assessment of Newfoundland and Labrador Hydro's 2024 Resource Adequacy Plan. For the Newfoundland and Labrador Board of Commissioners of Public Utilities. (August 2024).
- Management Review Audit of NorthWestern Energy Public Service Corporation d/b/a NorthWestern Energy. For the Nebraska Public Service Commission (August 2024).
- Post-Bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Summer 2024 Procurement of Indexed Renewable Energy Credits from Wind, Solar, Brownfield, and Hydropower Resources. For the Illinois Commerce Commission (July 2024).
- Assessment of Newfoundland and Labrador Hydro's Long-Term Load Forecast Report – 2023. For the Newfoundland and Labrador Board of Commissioners of Public Utilities. (July 2024).
- Initial Comments on the Summer 2023 Through Spring 2024 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2024).
- Initial Comments on the Summer 2023 Through Spring 2024 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2024).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2024 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (May 2024).
- The Independent Observer's Report Regarding Hawaiian Electric Light Company, Inc.'s Request for Proposals for North Kohala Energy Storage for Integration with Microgrid on Island of Hawaii. For the Hawaii Public Utilities Commission (April 2024).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2024 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2024).
- Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement. For the Mississippi Public Service Commission (December 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company December 2023 Procurement of Indexed Renewable Energy Credits from Wind, Solar, and Brownfield Solar Resources. For the Illinois Commerce Commission (December 2023).
- The Independent Evaluator's Report Regarding Public Service Company of New Mexico's Request for Proposals for Firm Capacity Resources with Guaranteed Commercial Operation Dates of April 1, 2026 or Earlier. Presented to the New Mexico Public Regulation Commission. (November 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2023 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2023).

- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2023 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2023).
- Management Review Audit of Black Hills Nebraska Gas, LLC d/b/a Black Hills Energy. For the Nebraska Public Service Commission (August 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Summer 2023 Procurement of Indexed Renewable Energy Credits from Wind, Solar, and Brownfield Solar Resources. For the Illinois Commerce Commission (June 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2023 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (June 2023).
- Initial Comments on the Summer 2022 Through Spring 2023 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2023).
- Initial Comments on the Summer 2022 Through Spring 2023 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2023 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2023).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Early 2023 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (February 2023).
- Management Review Audit of Mississippi Power Company Fuel and Electricity Procurement. For the Mississippi Public Service Commission (December 2022).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company December 2022 Procurement of Indexed Renewable Energy Credits from Wind, Solar, and Brownfield Solar Resources. For the Illinois Commerce Commission (December 2022).
- Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2020-2021. For the Nova Scotia Utility and Review Board (November 2022).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2022 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2022).
- Initial Comments on the Summer 2021 Through Spring 2022 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2022).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Delivery of Grid Services from Customer-Sited Distributed Energy Resources on Island of O'ahu. For the Hawaii Public Utilities Commission (June 2022).
- Initial Comments on the Summer 2021 Through Spring 2022 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2022).

- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Supplemental Spring 2022 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (May 2022).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2022 Procurement of Indexed Renewable Energy Credits from Wind, Solar, and Brownfield Solar Resources. For the Illinois Commerce Commission (May 2022).
- The Independent Observer's Report Regarding Hawaiian Electric Companies' Kupono Solar-Plus-Storage Project and Power Purchase Agreement on Oahu. For the Hawaii Public Utilities Commission (April 2022).
- Post-Application Report of the Procurement Monitor for the Ameren Illinois Company and Commonwealth Edison Company Procurement of Renewable Energy Credits Under the Coal to Solar and Energy Storage Initiative. For the Illinois Commerce Commission (April 2022).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2022 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (April 2022).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2022 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2022).
- Post-bid Report of the Procurement Monitor for the Commonwealth Edison Company's 2021 Procurement of Carbon Mitigation Credits. For the Illinois Commerce Commission (November 2021).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2021 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2021).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2021 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2021).
- Initial Comments on the Summer 2020 Through Spring 2021 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2021).
- Initial Comments on the Summer 2020 Through Spring 2021 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2021).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2021 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (April 2021).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2021 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2021).
- Post-bid Report of the Procurement Monitor for the Illinois Power Agency March 2021 Procurement of Renewable Energy Credits from Utility-Scale Wind Resources. For the Illinois Commerce Commission (March 2021).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage on Hawai'i. For the Hawaii Public Utilities Commission (December 2020).

- Comments on Nova Scotia Power, Inc.'s Final Integrated Resource Plan Report. For the Nova Scotia Utility and Review Board (December 2020).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage on O'ahu. For the Hawaii Public Utilities Commission (October 2020).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Delivery of Grid Services from Customer-Sited Distributed Energy Resources on Islands of O'ahu, Maui, and Hawai'i. For the Hawaii Public Utilities Commission (October 2020).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2020 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2020).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2020 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2020).
- Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019. For the Nova Scotia Utility and Review Board (August 2020).
- Initial Comments on the Summer 2019 Through Spring 2020 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2020).
- Initial Comments on the Summer 2019 Through Spring 2020 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2020).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's April 2020 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (April 2020).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2020 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2020).
- Post-bid Report of the Procurement Monitor for the Illinois Power Agency Low-Income Community Solar Pilot Request for Proposals. For the Illinois Commerce Commission (December 2019).
- Post-bid Report of the Procurement Monitor for the Illinois Power Agency December 2019 Procurement For Renewable Energy Credits from Non-Solar Community Renewables. For the Illinois Commerce Commission (December 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company and Commonwealth Edison Company October 2019 Utility-Scale Wind Procurement for Renewable Energy Credits from Wind Resources. For the Illinois Commerce Commission (October 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2019 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2019 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2019).
- Pre-Bid Report of the Independent Observer for the Hawaiian Electric Companies' Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage on O'ahu and Hawai'i Island and for

Delivery of Grid Services from Customer-Sited Distributed Energy Resources. For the Hawaii Public Utilities Commission (August 2019).

- Post-Bid Report of the Procurement Monitor for the Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company July 2019 Procurement for Renewable Energy Credits from Brownfield Solar Resources. For the Illinois Commerce Commission (July 2019).
- Initial Comments on the Summer 2018 Through Spring 2019 Renewable Resource Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2019).
- Initial Comments on the Summer 2018 Through Spring 2019 Electric Procurement Events, Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (May 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2019 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (April 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2019 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2019).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Dispatchable and Renewable Generation on Hawai'i Island. For the Hawaii Public Utilities Commission (January 2019).
- Independent Observer's Report Regarding Hawaiian Electric Companies' Request for Proposals for Dispatchable and Renewable Generation on O'ahu. For the Hawaii Public Utilities Commission (January 2019).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company November 2018 Utility-Scale Wind Procurement for Renewable Energy Credits from Brownfield and Utility-Scale Solar Resources. For the Illinois Commerce Commission (November 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company October 2018 Utility-Scale Wind Procurement for Renewable Energy Credits from Wind Resources. For the Illinois Commerce Commission (October 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2018 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (September 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2018 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2018).
- Initial Comments on Summer 2017 through Spring 2018 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (July 2018).
- Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2016-2017. For the Nova Scotia Utility and Review Board (July 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company April 2018 New Solar Procurement for Renewable Energy Credits from Solar Resources. For the Illinois Commerce Commission (April 2018).

- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Spring 2018 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (April 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2018 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company March 2018 New Solar Procurement for Renewable Energy Credits from Solar Resources. For the Illinois Commerce Commission (March 2018).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's February 20, 2018 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (February 2018).
- Report of the Commission's Consultant Regarding FirstEnergy's Supplemental February 2018 PIPP RFP. For the Public Utilities Commission of Ohio (February 2018).
- The Independent Evaluator's Final Report on Pacificorp's 2017R Request for Proposals. Presented to the Oregon Public Utility Commission (February 2018).
- Pre-Bid Report of the Independent Observer for the Hawaiian Electric Companies' Request for Proposals for Dispatchable and Renewable Generation on O'ahu and Hawai'i Island. Presented to the Hawai'i Public Utilities Commission (February 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company 2017/2018 Procurement for Zero Emission Credits. For the Illinois Commerce Commission (January 2018).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company 2017 Initial Forward Procurement for Renewable Energy Credits from Wind and Solar Resources. For the Illinois Commerce Commission (September 2017).
- The Independent Evaluator's Assessment of PacifiCorp's Final Draft 2017R Request for Proposals. For the Oregon Public Utility Commission (August 2017).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's Fall 2017 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (August 2017).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Fall 2017 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (August 2017).
- Initial Comments on Summer 2016 through Spring 2017 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (July 2017).
- Report of the Commission's Consultant Regarding Dayton Power & Light's 2017 PIPP RFP. For the Public Utilities Commission of Ohio (May 2017).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2017 RFP to Procure Distributed Generation Renewable Energy Credits. For the Illinois Commerce Commission (May 2017).
- Report of the Commission's Consultant Regarding Dayton Power & Light's April 2017 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (April 2017).

- Report of the Commission's Consultant Regarding Duke Energy Ohio's Supplemental April 2017 PIPP RFP. For the Public Utilities Commission of Ohio (April 2017).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2017 RFPs to Procure Block Energy/Standard Products. For the Illinois Commerce Commission (April 2017).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's March 2017 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (March 2017).
- Report of the Commission's Consultant Regarding FirstEnergy's January 2017 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (February 2017).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's November 2016 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (November 2016).
- Report of the Commission's Consultant Regarding FirstEnergy's October 2016 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (October 2016).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company's Fall 2016 RFPs to Procure Standard Block Energy Products. For the Illinois Commerce Commission (September 2016).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's September 2016 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2016).
- Expert Report Concerning Hydro-Québec TransÉnergie's Acceptance of Capacity E-Tags for Reserve Scheduling. Régie de l'énergie, No. P-130-004 (May 2016).
- Initial Comments on Summer 2015–Spring 2016 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2016).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company 2016 RFPs to Procure Renewable Energy Credits. For the Illinois Commerce Commission (May 2016).
- Post-bid Report of the Procurement Monitor for the Ameren Illinois Company, Commonwealth Edison Company, and MidAmerican Energy Company Spring 2016 RFPs to Procure Standard Block Energy Products. For the Illinois Commerce Commission (April 2016).
- Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing the Electricity Business. For the Southwest Power Pool Board of Directors (April 2016).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's March 2016 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (March 2016).
- Independent Observer's Report on the Results of the Negotiation Phase of Hawaii Electric Company's Request for Proposals for Renewable Geothermal Dispatchable Energy and Firm Capacity Resources. For the Hawaii Public Utilities Commission (February 2016).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's November 2015 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (November 2015).
- Report of the Commission's Consultant Regarding Dayton Power & Light's September 2015 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (September 2015).

- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's and Commonwealth Edison Company's September 2015 RFPs to Procure Standard Block Energy Products. For the Illinois Commerce Commission (September 2015).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's September 2015 RFP to Procure Zonal Resource Credits. For the Illinois Commerce Commission (September 2015).
- Initial Comments on the 2015 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act. For the Illinois Commerce Commission (June 2015).
- Report of the Commission's Consultant Regarding Duke Energy Ohio's May 2015 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (May 2015).
- Independent Observer's Final Report on Hawaii Electric Company's Final Request for Proposals for Renewable Geothermal Dispatchable Energy and Firm Capacity Resources. For the Hawaii Public Utilities Commission (May 2015).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's and Commonwealth Edison Company's 2015 RFPs to Procure Solar Renewable Energy Credits. For the Illinois Commerce Commission (April 2015).
- Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing the Electricity Business. For the Southwest Power Pool Board of Directors (April 2015).
- Post-bid Report of the Procurement Monitor for Ameren Illinois Company's and Commonwealth Edison Company's Spring 2015 RFPs to Procure Standard Block Energy Products. For the Illinois Commerce Commission (March 2015).
- Independent Auditor's Report on the Annual Management Review Audit of Entergy Mississippi, Inc. for October 1, 2012 through September 30, 2014. For the Mississippi Public Service Commission (December 2014).
- Report of the Commission's Consultant Regarding Dayton Power & Light's September 2014 Standard Service Offer Auction. For the Public Utilities Commission of Ohio (September 2014).
- Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing the Electricity Business. For the Southwest Power Pool Board of Directors (April 2014).
- Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors (April 2013).
- Independent Auditor's Report on the Annual Management Review Audit of Entergy Mississippi, Inc. For the Mississippi Public Service Commission (December 2012).
- Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors (April 2012).
- Review of Terms and Conditions for Long-Term Contracts for Renewable Ocean Energy. For the Governor's Office of Energy Independence and Security for the State of Maine (April 2012).
- Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors (April 2011).
- Summary of Discussion Regarding Boston Pacific's Integrated Marketplace Recommendations. For the Southwest Power Pool Board of Directors (March 2011).

- Review of the Southwest Power Pool's Integrated Marketplace Proposal. For the Southwest Power Pool Board of Directors (December 2010).

OTHER PROFESSIONAL EXPERIENCE

Prior to joining Bates White, Mr. Musco was a Managing Director with Boston Pacific Company, where he focused on market design, working on behalf of the Southwest Power Pool, state commissions, and wholesale market participants. Before that, he worked as an Economist with the Federal Energy Regulatory Commission on market design issues in the California ISO, PJM Interconnection, New England ISO, and New York ISO.

Selected experience

- Led efforts as Procurement Monitor on behalf of the Illinois Commerce Commission in the procurement of energy, capacity, zero emissions credits, and renewable energy credits from wind, solar, brownfield solar, and distributed generation for three Illinois utilities
- Testified on behalf of the Massachusetts Attorney General's Office regarding three Massachusetts electric utilities' request for remuneration payments under six offshore wind power purchase agreements
- Directed audit of Nova Scotia Power, Inc.'s fuel and electric power purchases and sales, on behalf of the Nova Scotia Utility and Review Board
- Consulting on behalf of a confidential market participant regarding capacity market design in Alberta
- Directed report on Southwest Power Pool's (SPP) Integrated Marketplace design and performed analysis on SPP's day-ahead market design, including resource adequacy issues, financial transmission rights, virtual bidding, creditworthiness requirements, settlements, and market monitoring.
- Consulted for SPP's Board of Directors on a variety of issues, including electric vehicles, demand response, distributed generation, bid cost recovery and resettlements, transmission cost allocation, retail electricity pricing, and compliance matters such as the Federal Energy Regulatory Commission's (FERC) Order No. 1000 and Dodd-Frank legislation
- Led a reliability audit of a major US utility on behalf of FERC and the North American Electric Reliability Corporation
- Consulted on behalf of the Texas Public Utilities Commission in analyzing a proposed acquisition of a major utility
- Led Boston Pacific's merchant transmission practice in designing and executing open seasons and open solicitations for private merchant transmission developers that meet FERC's open access and competitive requirements
- Evaluated competitive offers to build new geothermal resources in Hawaii, providing written reports to the Hawaii Public Utilities Commission
- Worked on US market rule and market design issues related to energy, capacity, ancillary services, demand response, financial transmission rights, virtual bidding, and scarcity pricing in most of the major US ISO and RTO markets

PUBLICATIONS

- "Communities Advancing the U.S. Energy Transition" (with Carolyn Berry). *IAEE Energy Forum* (First Quarter 2024).
- "Goldilocks and the Grid: Creating 'No Regrets' State Policies and Regulations for Electric Vehicles" (with Craig Roach, Nicolás Puga, and Glenn R. George). (May 2019). *Available at* https://www.bateswhite.com/media/publication/177_Goldilocks%20and%20the%20Grid.v2.pdf.
- "Unsung Benefits of Wholesale Competition to Electricity Customers Who Forgo Retail Competition." *Electricity Journal* (October 2017).
- "Why Shared, Autonomous Vehicles Will Be Electric." *BPC In Brief* (June 2016).
- With Craig Roach. "Federal Versus State Jurisdiction in the Electricity Business." *Public Utilities Fortnightly* (May 2016).
- "Illinois Helps Spur New Distributed Solar Generation." *BPC In Brief* (August 2015).
- "Are Decentralized Resources an Existential Competitive Threat to the Grid?" *BPC In Brief* (May 2015).
- "Back to Basics on Demand Response Compensation." *BPC In Brief* (October 2014).
- With Frank Mossburg. "Partnership, Not Preemption." *Public Utilities Fortnightly* (December 2013).

PRESENTATIONS AND PANELS

- "Electric Vehicles." Panelist at 47th Annual Public Utility Research Center Conference at the University of Florida "Rates, Realities, and Risks: Ratemaking for Tomorrow." Gainesville, FL (February 2020).
- "Barriers to Community Solar Adoption." Panelist at George Washington University's 2020 Community Solar Workshop "Examining Community Solar Programs to Understand the Role of Policies on Accessibility and Investment." Washington, DC (February 2020).
- "Avoiding Debates—Aligning Planning with Procurement." Presentation at the EUCI 2019 Hawai'i Power Summit, Post-Conference Workshop, Honolulu, HI (January 2019).
- "Assessing Available Carbon-Free/Renewable Generation Resources." Presentation at the EUCI 2019 Hawai'i Power Summit, Post-Conference Workshop, Honolulu, HI (January 2019).
- "Competitive Procurement in Hawai'i." Presentation at the EUCI 2019 Hawai'i Power Summit, Honolulu, HI (January 2019).
- "Overview of the 2017 Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Tulsa, OK (April 2017).
- "Overview of the 2017 Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (April 2017).
- "Case Study: New England Clean Power Link." Presentation at the 2016 Platts Transmission Planning and Development Conference, Arlington, VA (June 2016).
- "Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Santa Fe, NM (April 2016).

- "Preliminary Overview of the 2016 Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (March 2016).
- "Overview of the Open Solicitation Process for the New England Clean Power Link." Presentation at the Webex Information Session for TDI New England's Open Solicitation for the New England Clean Power Link, Washington, DC (November 2015).
- "Southwest Power Pool 2015 Annual Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Tulsa, OK (April 2015).
- "Preliminary Overview of the 2015 Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (March 2015).
- "Overview of the 2014 Annual Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Oklahoma City, OK (April 2014).
- "Preliminary Overview of the 2014 Looking Forward Report: Strategic Issues Facing the Electricity Business." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (March 2014).
- "Market Monitoring, Mitigation, and Competition." Joint presentation to the Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission, Washington, DC (May 2013).
- "Overview of the 2013 Annual Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Kansas City, MO (April 2013).
- "Preliminary Overview of the 2013 Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (March 2013).
- "Overview of the Annual Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Oklahoma City, OK (April 2012).
- "Overview of the Annual Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (March 2012).
- "A Basic Electricity Primer." Joint presentation at the Natural Gas / Renewable Energy Dialogue on Grid Integration Issues, Arlington, VA (June 2011).
- "Overview of the Annual Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors and Members Committee, Tulsa, OK (April 2011).
- "Status Report on the Integrated Marketplace Proposal." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (April 2011).
- "Overview of the Annual Looking Forward Report." Joint presentation to the Southwest Power Pool Board of Directors Oversight Committee, Washington, DC (April 2011).
- "Summary of Recommendations in Our Report: A Review of the Southwest Power Pool's Integrated Marketplace Proposal." Joint presentation to the Southwest Power Pool Board of Directors, New Orleans, LA (January 2011).

- "Technical Conference Regarding California Independent System Operator Corporation's Exceptional Dispatch Mechanism and Proposed Mitigation Plan." Staff Moderator at FERC's Technical Conference, Washington, DC (November 2008).
- "Reliability Standard Compliance and Enforcement in Regions with Independent System Operators and Regional Transmission Organizations." Staff Panel Member at FERC's Technical Conference, Washington, DC (September 2007).
- "Technical Conference Regarding Parameters for New York Independent System Operator's Installed Capacity Requirement Demand Curve." Staff Panel Member at FERC's Technical Conference, Washington, DC (March 2005).
- "Cross Sound Cable and 1385 Cables Settlement between the Northeast Utilities Service Company, Connecticut Light & Power, and the Long Island Power Authority." Staff Joint Presenter at FERC's Open Meeting, Washington, DC (June 2004).

Appendix B. *Curriculum Vitae* of Mr. Cain

BATES WHITE
ECONOMIC CONSULTING

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COLLIN CAIN, MSC

Partner

AREAS OF EXPERTISE

- **Economic, regulatory and market analysis**
- **Market design**
- **Asset valuation**
- **Damages estimation**
- **Forensic analysis**

SUMMARY OF EXPERIENCE

Mr. Cain chairs the Energy Practice at Bates White. He specializes in economic evaluation of wholesale energy markets, spanning electricity, fuels and environmental attributes. He has provided testimony and advised clients on market design in PJM, MISO, ISO New England, NYISO, ERCOT, Ontario, and Alberta. He has developed energy and capacity market pricing and risk analysis models, and has applied these models in a variety of consulting assignments to forecast energy prices, evaluate market design, value generation assets and power supply contracts and to develop supply hedging strategies. Mr. Cain has provided expert testimony in regulatory, court and arbitration proceedings. He has provided strategic advisory work on issues such as asset divestment, stranded cost recovery, and rate unbundling. Mr. Cain also applies his expertise in forensic analysis of the conduct and application of forecasts, market evaluation, and risk assessment by contract counterparties.

Mr. Cain has provided expert testimony on forecasting, market design, supply procurement, power market modeling, cost/benefit analysis, market power, cost allocation, contract damages, and energy market bidding behavior.

EDUCATION

- MSc, Economics, London School of Economics
- BA, Economics and Political Science Specialist, University of Toronto

SELECTED EXPERIENCE

- Evaluations of the 2024 integrated resource plans of Evergy (Kansas), Entergy Mississippi, and Mississippi Power.
- On behalf of Mississippi Public Utility Staff, evaluation of the proposed acquisition by Entergy Mississippi of an additional, approximately 209 MW, share of the Grand Gulf Nuclear Station.
- Expert testimony on behalf of the Data Center Coalition, before the Public Utility Commission of Oregon, regarding novel rate design proposals by PacifiCorp applicable to very large loads. The testimony addressed economic and regulatory issues related to the development of electric utility rates, and the incentive impacts of the proposed capacity reservation charge mechanism relative to a minimum demand charge.

- Expert testimony on behalf of the Kansas Corporation Commission Staff regarding the proposed acquisition of 800 MW of wind generation by Empire District Electric Company. Analysis included an assessment of energy and capacity needs, projected wind energy production, curtailment risk, projected value from proposed tax equity partnership, and risk allocation between investors and ratepayers.
- On behalf of Mississippi Public Utility Staff, evaluated the proposed acquisition by Entergy Mississippi of a 100 MW solar project located in Sunflower County, MS. Assessed the rationale, evidentiary support, costs, benefits and risks associated with the proposed transaction. Submitted testimony before the Mississippi Public Service Commission.
- Affidavit in FERC proceeding (FERC Docket No. ER16-49-000, *et al.*) on behalf of the Electric Power Supply Association (EPSA) evaluating multiple proposals by PJM and other market participants to modify the PJM capacity market.
- In separate fuel audits of Nova Scotia Power for 2016-2017 and 2018-2019, on behalf of the Nova Scotia Utility and Review Board, evaluated the cost recovery provisions of the utility's Load Retention Tariff (LRT) and replacement Extra Large Industrial Active Demand Control Tariff (ELIADC), including the effectiveness of provisions to shield other utility customers from incremental costs of serving load under the tariff.
- On behalf of ALLETE Clean Energy, Inc., prepared fuel and electric energy price forecasts and estimated damages in PPA contract arbitration.
- Evaluation of proposed modifications of the ERCOT electric power markets intended to support reliability of the system through capacity support mechanisms.
- Evaluation of solar PPA transactions totaling 420 MW of installed capacity proposed by Entergy Mississippi as part of its "EDGE" resource strategy. Assessed the costs, benefits and risks of the proposed PPAs on behalf of Mississippi Public Utility Staff.
- Assisted the Kansas Corporation Commission Staff in the development of integrated resource plan (IRP) guidelines for analysis and reporting by jurisdictional utilities in Kansas.
- Provided review, analysis and comments in utility IRP development processes in Nova Scotia, Kansas, and Mississippi on behalf of retail regulators.
- Continuing advisory services on behalf of the Mississippi Public Service Commission, addressing issues associated with participation in the MISO RTO, including market design for energy, ancillary services and capacity; benefits assessment; system planning; cost allocation.
- Expert testimony on behalf of Kansas Corporation Commission Staff regarding recovery of costs proposed by the Empire District Electric Company for 600 MW of utility owned wind projects.
- Consulting advisory services evaluating PJM market design and potential modifications to the capacity market and scarcity pricing mechanisms, on behalf of a market participant.
- Affidavits in FERC proceeding (FERC Docket No. ER21-2582-000) on behalf of the Electric Power Supply Association (EPSA) evaluating PJM's proposed modification of the minimum offer price rule (MOPR) applied in the RPM capacity market.
- Expert testimony on behalf of Skipjack Offshore Energy, LLC (Ørsted) before the Maryland Public Service Commission on the estimated economic impacts and retail electricity rate effects associated with Ørsted's applications in Round 2 of Maryland's offshore wind selection process.
- On behalf of the Mississippi Public Service Commission (MPSC), evaluated costs and benefits of Entergy's proposal to join the Midwest Independent System Operator (MISO) regional transmission organization. The

analysis included assessment of prior cost-benefit studies as well as independent production cost modeling of the benefits to the Entergy region from joining MISO.

- In support of a major wind farm development in Mexico, conducted a due diligence review of the project PPA price model and its application in projecting project revenues. The evaluation addressed the representation of the renewable energy banking mechanism and the priority lists for allocating project energy and capacity to load centers, and consistency with the CFE interconnection agreement.
- On behalf of the Mississippi Public Service Commission and the Arkansas Public Service Commission, testimony in a complaint at FERC regarding the renewal of sale-leaseback agreements covering a portion of the Grand Gulf Nuclear Station, addressing potential double collection of costs for plant upgrades.
- On behalf of Mississippi Public Utility Staff, evaluated the proposed acquisition by Entergy Mississippi of the Choctaw Generating Station, an 810 MW air-cooled combined cycle power plant located in Choctaw County, MS. Assessed the utility's economic evaluation of the transaction, the due diligence performed, and the performance history of the plant.
- Expert testimony on behalf of the U.S. government regarding offsets to damages claimed by Alabama Power Company and Georgia Power Company resulting from the Government's partial breach of the spent nuclear fuel "Standard Contract", specifically relating to onsite spent fuel storage costs incurred at the Farley, Hatch, and Vogtle nuclear power plants.
- For the owner of an IPP combined cycle power plant in Mexico, performed an analysis of plant residual value after the expiration of a 25 year PPA with CFE. The valuation applied two distinct methodologies: an "equivalent plant" approach, and a "cost-of-new-entry" approach. Scenarios were conducted for different escalation rates for natural gas prices and capital costs.
- Evaluated competitive impacts from Tucson Electric Power's proposal for utility-owned rooftop solar and community solar. The analysis, in support of testimony before the Arizona Public Service Commission, assessed the status of the competitive market for distributed generation and the likely impacts from proposed utility offerings.
- Evaluation of transportation fuel price drivers in the California market, including effects of the state Low Carbon Fuel Standard, Cap-and-Trade program, and fuel blend standards.
- Expert declaration supporting a Motion for Stay of Agency Action filed against the EPA by Producers of Renewables United for Integrity Truth and Transparency in the U.S. Court of Appeals for the D.C. Circuit. Analysis addressed impacts of EPA actions granting exemptions to small refineries otherwise obligated under the Renewable Fuel Standard (RFS) program.
- Evaluation of supply, demand and economics of renewable natural gas industry in the U.S., including production pathways and technologies, demand drivers, and support from state and federal programs, particularly EPA's RFS and California's LCFS programs.
- Development of a new pricing mechanism for liquid fuels in South Africa. The work, performed for the South African Department of Minerals and Energy, established pricing methods and regulatory accounts to ensure that fuel prices appropriately reflect costs, and enhance industry investment incentives.
- Developed fuel forecasts for the Mexican power market applied in projecting retail electricity rates and the valuation of renewable energy projects and associated PPAs.
- Testimony on behalf of Catalyst Paper Operations, Inc., presenting an analysis of FERC's market power screens supporting Catalyst's market based rate application associated with its acquisition of power generating facilities.

- Evaluated the proposed spin-merge of Entergy's transmission assets to ITC Holdings Corp., and advised the Mississippi Public Service Commission on the costs and benefits to Mississippi, including impacts on state regulatory control.
- Quantified effects on New Jersey energy costs of the prospective merger between PSEG and Exelon Corp as part of a comprehensive cost-benefit analysis for the NJ BPU. Effects included wholesale price impacts from changes to nuclear plant availability, direct costs to the state arising from planned staff reductions, and reductions in PSE&G's regulated cost of service arising from estimated merger synergies.
- Affidavit in FERC proceeding (FERC Docket No. ER18-1314-000) on behalf of the Electric Power Supply Association (EPSA) regarding PJM's proposed Capacity Repricing mechanism to modify the PJM capacity market auctions to address state subsidies to certain generating units in PJM.
- Affidavit on behalf of the Electric Power Supply Association in FERC's *Grid Reliability and Resilience Pricing* docket (RM18-1-000). Analyzed market effects of proposed out-of-market subsidy payments to coal and nuclear generating units in ISO/RTO markets.
- Submitted testimony on behalf of Constellation Energy Commodities Group, Inc. in a complaint proceeding before FERC (Docket No. EL07-47-000) regarding the Illinois electricity supply auction. Analyzed the conduct, bidding behavior and outcome of the auction, addressing auction structure and rules, and allegations of market manipulation.
- Conducted economic assessment of KCP&L's proposed $1.2 billion environmental retrofit of La Cygne Generating Station, and testified before the Kansas Corporation Commission on behalf of Commission Staff. Developed analysis framework and key factor inputs for alternative economic assessment and evaluated supporting analyses submitted by KCP&L.
- Directed power market projections and economic benefit analyses in various applications, including: study of economic benefits for the Niagara Power Project (NYPA); cost-benefit analysis of environmental protection alternatives related to fueling of Salem Generation Station (PSE&G) and Indian Point Nuclear Power Plant (Entergy) and to the operation of Danskammer Point Generating Station (Dynegy).
- Submitted testimony at FERC on behalf of the Mississippi Public Service Commission regarding the allocation of settlement benefits among the Entergy operating companies. The testimony quantified shortfalls in benefits owed to Entergy Mississippi related to a settlement by Entergy resolving damage claims from a coal transportation disruption that restricted output at two of Entergy's generating plants.
- Conducted independent validation of Southern California Edison's (SCE) internal power supply risk assessment model, including the model's theoretical underpinnings, implementation, and interpretation of outputs. The SCE model assesses procurement cost risk based on stochastic simulation that accounts for dispatchable resources, supply contracts, power forward and gas forward positions.
- Calculated damages and submitted expert testimony on behalf of PG&E, SCE and SDG&E in separate cases before the U.S. Court of Federal Claims and Los Angeles Superior Court regarding unresolved claims stemming from energy sales by defendants into the PX and ISO markets during the California energy crisis.
- Developed RFP documents and evaluation procedures for the Ontario Ministry of Energy's 2500MW RFP. Directed the economic evaluation of generator proposals, including development of models used to estimate energy market revenues and contingent capacity support payments, and created analytical tools to evaluate aggregate costs, including transmission upgrade cost impacts, for every possible portfolio of submitted bids.
- Developed probabilistic risk management model for market price forecasting, asset valuation and power supply cost analysis. Adapted and implemented the model in applications for Oglethorpe Power Corporation

(OPC), Central Maine Power Company, Vermont Yankee Nuclear Power Corporation, Commonwealth Electric Company, and Connecticut Yankee Atomic Power Company. Analyses included forecasting market clearing energy and capacity prices, and estimating hedge values for retained capacity, new unit construction, power supply bids, and financial derivatives.

- Evaluated power supply proposals for short-term and long-term RFPs by OPC, directing and assessing PROMOD scenarios for alternative supply portfolios. Created and applied an independent price forecasting model and Monte Carlo analysis to evaluate risk profiles of supply alternatives.
- Provided analytical support for RFP design and portfolio evaluation in the Ireland 500 MW capacity procurement.
- Assisted the development and implementation of BG&E's solicitation of standard offer supply service. Estimated market energy and capacity prices in a 15-year forecast applying a proprietary linear programming/optimal system expansion model.
- Served as testifying expert and produced expert report for OPC in arbitration proceedings between OPC and LG&E Power Marketing (LG&E) regarding LG&E's valuation of coal supply contracts associated with a long-term power purchase and sale agreement.
- Evaluated the Public Service Company of Oklahoma's 2008 Supply Side RFP in support of testimony for a potential bidder. Assessed bid evaluation methodology, credit and collateral requirements, and implementation of debt equivalence adjustments.
- Managed the Data and Rate Design Committees and Backup Bidding Team for the annual auctions of New Jersey Basic Generation Service (BGS). Participated in development of auction process, rules and protocols, and regulatory filings. Directed bidder information procedures and auction Data Room Team. Conducted PJM wholesale market price assessment to determine starting prices for the descending clock auction.
- Conducted benefits analysis of proposed hydroelectric power plant development in New York State, including reliability benefits, environmental benefits and wholesale market price impacts.
- Directed economic analyses and produced white papers on the economic benefits of baseload generation from nuclear power plants on behalf of Exelon Corporation. Benefit analysis examined impacts on wholesale market prices, and peak hour power flow impacts. (Separate assignments for 5 nuclear plants: Oyster Creek, Limerick, TMI, Peach Bottom, and proposed restart of Zion).
- On behalf of Occidental Chemical Corporation, evaluated proposed changes to cost allocation methods in the Entergy production cost sharing mechanism, in support of testimony in FERC proceeding (Docket No. ER07-682-000). The evaluation estimated the impact on the individual Entergy operating companies and assessed compliance with regulatory accounting principles.
- Evaluated PJM proposals to modify OATT allocation of cost responsibility for transmission upgrades under the Regional Transmission Expansion Plan (RTEP), supporting testimony in FERC Docket EL07-57-000 (Consolidated).
- Advised the Ontario Power Authority in generator contract dispute arising from rule modifications by the Independent Electric System Operator (IESO). Provided assessment of background and intent of contract payment mechanisms and preliminary analysis of revenue impacts of rule changes on generator counterparties.
- Submitted testimony before FERC on behalf of the MPSC regarding Entergy Louisiana's proposal to allocate cancelation costs of the Little Gypsy Repower Project through the Entergy Service Agreement's rough production cost equalization mechanism.

- Developed forecast model of the CFE (Mexican electric utility) short-run cost of generation (CTCP) in support of the acquisition of a large scale wind project in Oaxaca, México. The model allowed for evaluation of potential project revenue impacts associated with increased gas-fired and renewable generation on the CFE system.
- As an advisor to a major capital finance entity, evaluated the project financial model for a proposed hydroelectric generation project in western Mexico. The model review considered representation of the renewable energy banking mechanism under Mexican energy regulation, representation of seasonal production and demand patterns, and the associated projection of profit and loss and debt service coverage of the life of the project.
- Conducted detailed valuation analysis of qualifying facility (QF) hydro plants for New York State Electric & Gas Corporation (NYSEG), supporting settlement negotiations with plant owners. The analysis considered the value to NYSEG of buying out the contracts or assuming ownership under expected default by the plant owners.
- Conducted assessment of potential effects on wholesale markets and default service procurement of the proposed merger of Exelon Corp. and Constellation Energy Group Inc., in support of testimony submitted to the Maryland Public Service Commission on behalf of Commission Staff.
- Evaluated power market modeling employed by a party in a major supply contract litigation. Evaluated the party's application of PROMOD and MIDAS models used to value the transaction, and associated risk analyses used to assess value at risk (VaR). Identified substantive errors in inputs, contemporaneous market assumptions, risk analysis and economic inference.
- Conducted due diligence assessment of the financial modeling of off-taker PPA revenues for the 396MW Mareña wind power project in southern Mexico, including the representation of off-taker priority list weighting and energy banking under CRE renewable interconnection rules.
- Conducted valuations of all Central Maine Power (CMP) power plants, supporting negotiated sale of generation assets to FPL. Applied market price forecasts and extensive monte carlo analyses to examine multiple transaction scenarios, including the value of retaining hydroelectric facilities as a supply hedge during the transition to competition. FPL Energy agreed to pay $845 million for all of CMP's non-nuclear generating assets.
- Produced power plant valuation of the TNP One lignite-fueled unit for Texas-New Mexico Power Company to support asset sale strategy as well as litigation with respect to stranded costs.
- Directed power market price forecasts for multiple clients, applying proprietary linear programming model to evaluate optimal capacity expansion for fuel price, demand growth and technology scenarios.
- Provided consulting assistance to the U.S. Department of Justice in defending claims related to spent nuclear fuel breach of contract in *Vermont Nuclear Power Corporation, and Entergy Nuclear Vermont Yankee, LLC et al., v. The United States* in the United States Court of Federal Claims (Nos. 02898C & 03-2663C) and *Portland General Electric Company et al., v United States of America* in the United States Court of Federal Claims (No. 04-0009C).
- Assessed the benefit-cost evaluation methods and assumptions applied to the 2010-12 energy efficiency plans in Massachusetts, for the Office of the Attorney General of Massachusetts.
- Conducted extensive analyses for a California IOU in refund proceedings related to the California energy crisis. Examined impacts of the calculation and application of mitigated market clearing prices (MMCPs) in the determination of refunds owed by generators selling into the California markets.

- For Baltimore Gas & Electric (BGE) testimony before the Maryland Public Service Commission, estimated rate impacts for alternative supply scenarios. Conducted power market analysis, estimation of wholesale market impacts on retail supply auction results, and self-build generation analysis.
- Estimated benefits of competition in electric markets through four empirical analyses, and quantified the dollar benefits to Maryland consumers of wholesale competition in PJM and state retail restructuring.
- Developed economic analysis of PJM transmission cost allocation proposals for merchant transmission entity. Supported testimony filed at FERC in Docket No. ER06-880-000, *et al*.
- Directed the evaluation of the benefit-cost ratio methodology used to validate energy efficiency measures in Massachusetts.
- Evaluated PJM price formation, demand responsiveness, and DR compensation proposals for comments submitted on FERC's ANOPR on "Wholesale Competition in Regions with Organized Electric Markets" (Docket Nos. RM07-19-000 and AD07-7-000).
- Performed strategic consulting work for BGE. Prepared expert testimony submitted in Maryland electric utility restructuring proceedings and consulted on utility regulatory strategy. Addressed market impact and economic rationale of competition policy, strategic aspects of asset disposition, stranded cost recovery, and retail access.
- Consulted on asset valuation alternatives and stranded cost recovery strategy, including the application of an auction appraisal of generation assets, for Niagara Mohawk Power Corporation.
- Directed study reviewing current methods of load profiling for retail settlement and energy imbalance services in the U.S. and Canada. The work was included in a series of load profiling studies for Japan's Ministry of Economy, Trade, and Industry.
- For ISO-NE, the NYISO and PJM Interconnection, in the evaluation of the proposed centralized resource adequacy model (CRAM): assessed capacity cost recovery for varied market conditions and implications for timing and frequency of capacity auctions.
- Conducted an analysis of reserve margin impacts on energy price volatility in the development of a power supply procurement process for Acquirente Unico, the Italian electric market single buyer.
- Directed analysis of optimal market hedge ratios by customer class for Dayton Power and Light. Analysis examined risk exposure due to price-driven customer migration under proposed retail access program.
- Produced pro forma valuation for the non-nuclear portion of the Connecticut Yankee nuclear site. Study considered unique site value and costs for a new generating plant, project financing costs, and the future competitive environment including market energy and capacity prices.
- Served as testifying expert on market modeling before the Massachusetts Department of Telecommunications and Energy on behalf of Commonwealth Electric. Testimony supported analysis of Commonwealth Electric's stranded costs and buyout options for legacy power purchase agreements.
- Directed new coal generation feasibility study for proposed investment in the Four Corners region of New Mexico. The analysis included market demand, competing supply, availability and cost of electrical transmission, cost and deliverability of coal, availability of water, and environmental concerns.
- Conducted a comprehensive review of the retail access experience in New England states. Developed state-by-state profiles that outlined the regulatory regime, transition period, standard-offer and default-service provisions. Evaluated end-user and supplier exposure to variable market prices.

- Provided consulting services to Niagara Mohawk Power Corporation on the modeling of transaction value for outsourcing standard offer service.
- Evaluated the competitive market of potential suppliers for PSE&G's auction of standard offer supply.
- Advised on the theoretic foundations of economic cost concepts and regulatory applications in avoided cost cases for a group of northeast electric utilities.
- Evaluated measures of competitiveness in present and future wholesale power markets and developed several models for use in assessing forward product prices for a large U.S. public power company.
- Participated in power purchase prudence analyses for PG&E, Nevada Power Company, Texas New Mexico Power Company, and Public Service Company of Colorado.

OTHER PROFESSIONAL EXPERIENCE

Prior to joining Bates White, Mr. Cain served as a Consultant at National Economic Research Associates (NERA). In this position, he conducted a variety of power sector analyses in NERA's energy practice. Mr. Cain also served as an Economist with Jones Lang Wootton USA, where he directed economic research and market analysis for a range of corporate clients. Previously, Mr. Cain was a Consultant with Apogee Research, where he conducted economic impact analyses, and participated in a variety of transportation and environmental economics consulting assignments.

EXPERT TESTIMONY

- On behalf of the Data Center Coalition, *In the Matter of Pacificorp, dba Pacific Power, Request for General Rate Revision* (OPUC Docket No. UE 433). Written direct testimony.
- On behalf of ALLETE Clean Energy, Inc., *Caddo Wind, LLC v. Hormel Foods Corporation* (JAMS arbitration). Expert Report, live testimony at hearing.
- On behalf of the Staff of the Kansas Corporation Commission, *IMO Application of The Empire District Electric Company for the Commission to Make Certain Changes in its Charges for Electric Service* (KCC Docket No. 21-EPDE-444-RTS). Written testimony.
- On behalf of Skipjack Offshore Energy, LLC, in Maryland Public Service Commission Case No. 9666. Written direct, supplemental direct, and rebuttal testimonies; live testimony at hearing.
- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER21-2582-000). Affidavit and supplemental affidavit.
- On behalf of the Mississippi Public Utility Staff, in Mississippi Public Service Commission Docket No. 2018-UA-267. Written testimony.
- On behalf of the Mississippi Public Utility Staff, in Mississippi Public Service Commission Docket No. 2018-UA-204. Written testimony.
- On behalf of the Mississippi Public Service Commission and the Arkansas Public Service Commission, *Louisiana Public Service Commission v. System Energy Resources, Inc., and Entergy Services, Inc.*, Federal Energy Regulatory Commission (Docket No. EL18-152-000). Written testimony.
- On behalf of Producers of Renewables United for Integrity Truth and Transparency supporting Motion for Stay of Agency Action filed against the EPA, in the U.S. Court of Appeals for the D.C. Circuit. Expert declaration.

- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER18-1314-000). Affidavit.
- On behalf of Petitioners-Plaintiffs (Hudson River Sloop Clearwater, Inc., and others) in New York State Supreme Court (Index No. 07242-16). Affidavit.
- On behalf of the Electric Power Supply Association, *Calpine Corporation v. PJM Interconnection, L.L.C.*, FERC (Docket No. ER16-49-000, *et al.*). Affidavit.
- On behalf of the United States, *Alabama Power Company and Georgia Power Company v. The United States*, in the U.S. Court of Federal Claims (No. 14-167C and No. 14-168C). Expert report; live testimony.
- On behalf of the Electric Power Supply Association, *PJM Interconnection, L.L.C.*, FERC (Docket No. ER18-1314-000). Affidavit.
- On behalf of the Staff of the Kansas Corporation Commission, *IMO the Petition of The Empire District Electric Company for Approval of Its Customer Savings Plan* (KCC Docket No. 18-EPDE-184-PRE). Written testimony.
- On behalf of the Electric Power Supply Association, *Grid Reliability and Resilience Pricing*, FERC (Docket No. RM18-1-000). Affidavit.
- On behalf of Calpine Corporation and NRG Energy, Inc., Application of Centerpoint Energy Houston Electric, LLC to Amend a Certificate of Convenience and Necessity for a Proposed 345-kV Transmission Line (…), Public Utility Commission of Texas (Docket No. 473-15-3595). Written testimony; live testimony at hearing.
- On behalf of Catalyst Paper Operations, Inc., *Catalyst Paper Operations Inc.*, FERC (Docket No. ER15-794-002). Written testimony.
- On behalf of the Mississippi Public Service Commission, *Entergy Services, Inc.*, FERC (Docket No. ER13-432-002). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company and the State of California, *Pacific Gas and Electric Company and Southern California Edison Company v. The United States; San Diego Gas & Electric Company v. The United States*, in the U.S. Court of Federal Claims (No. 07-157C and No. 07-167C, Consolidated; No. 07184C). Written testimony; deposition testimony.
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services, Inc., et al.*, FERC (Docket No. EL09-61-004). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of the Mississippi Public Service Commission, *Louisiana Public Service Commission v. Entergy Services Inc., et al.*, before the FERC (Docket Nos. ER12-1384, *et al.*). Written testimony; deposition testimony; live testimony at hearing.
- On behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, *Electric Refund Cases,* in the Superior Court of the State of California (Judicial Council Coordination Proceeding No. JCCP 4512). Written testimony; deposition testimony.
- On behalf of the Staff of the Kansas Corporation Commission, IMO the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239, before the Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE). Expert report; live testimony at hearing.

- On behalf of Constellation Energy Commodities Group, Inc., *The People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, et al.*, FERC (Docket No. EL07-47-000). Affidavit.
- On behalf of Oglethorpe Power Corporation, in contract dispute brought by LG&E Energy Corp. and LG&E Energy Marketing, Inc. (CPR Arbitration proceeding). Expert report; deposition testimony; live testimony.
- On behalf of Commonwealth Electric Company, Petition of Cambridge Electric Light Company and Commonwealth Electric Company requesting approval of their Transition Charge Reconciliation Filing, before the Massachusetts Department of Telecommunications and Energy (Docket No. DTE 99-90). Live testimony.

PUBLICATIONS AND PRESENTATIONS

- “Renewable Natural Gas Supply and Demand for Transportation” White paper (June 2019).
- “Biodiesel Distribution in the US and Implications for RFS2 Volume Mandates” (July 2016).
- “Clean Energy Certificates: The Key to Renewable Energy Financing,” with Nicolás Puga. Electricity Future Forum Mexico 2014 (November 2014).
- “Evaluation of the Entergy Mississippi Proposal to Join MISO,” Report to the Mississippi Public Service Commission. (August 2012, Revised)
- “Beyond Loan Guarantees: Fostering U.S. Nuclear Investment in a Post-Fukushima World,” with Glenn George. Conference paper and presentation, Center for Research in Regulated Industries 30th Annual Eastern Conference. Skytop, PA (May 2011).
- “Retail Rate Comparisons and the Electric Restructuring Debate,” with Jonathan Lesser. Bates White briefing paper, 2008-E-11-01. (November 2008).
- “Economic and System Reliability Benefits of the Three Mile Island Generating Station,” with Spencer Yang and Jonathan Lesser. White paper (April 2008).
- “Trends in Electricity Deregulation.” Conference presentation at DTN/Meteorlogix Energy Summit. Minneapolis (June 2008).
- “A Common Sense Guide to Wholesale Electric Markets,” with Jonathan Lesser. White paper (April 2007).
- “Utility Mergers: The Exelon-PSEG Merger.” Workshop presentation, Market Power, Mergers, and Governance, Center for Research in Regulated Industries. Newark (January 2007).
- “The Fallacy of High Prices,” with Howard Axelrod and David DeRamus. Public Utilities Fortnightly 144 (November 2006).
- “Nuclear Power in Future Electric Rate Cases.” Conference presentation, Managing the Modern Utility Rate Case, Law Seminars International. Las Vegas (February 2006).
- “Applications of Probabilistic Price Modeling.” Workshop presentation, Marginal Cost Working Group. Washington, DC (September 2004).
- “The 2004 BGS Auctions,” Presentation to American PowerNet. PJM Interconnection, Norristown, PA (December 2003).
- “RTO Formation in the Central and Southeast United States.” Presentation to Iberdrola S.A. Washington, DC (July 2003).