Assessment of Newfoundland and Labrador Hydro's 2024 Resource Adequacy Plan

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

Prepared by
Vincent Musco
Collin Cain
Nick Puga

August 30, 2024

TABLE OF CONTENTS

List of Tables

List of Figures

Abbreviations Used in Report

AACE – American Association of Cost Engineering
AESO – Alberta Electric System Operator
Bates White – Bates White, LLC
BDE – Bay d'Espoir
BDE 7 – Bay d'Espoir Unit 7
BDE-SOP -- Bay d'Espoir to Soldiers Pond
BESS – Battery Energy Storage Systems
Board – Board of Commissioners of Public Utilities
CCCT – Combined-Cycle Combustion Turbines
CCP – Critical Peak Pricing
CT – Combustion Turbine
DAFOR – Derated Adjusted Forced Outage Rates
DAUFOP – Derated Adjusted Utilization Forced Outage Probability
Daymark – Daymark Energy Advisors
ECA – Energy and Capacity Agreement
ECDM – Electrification, Conservation, and Demand Management
EFORd – Equivalent Forced Outage Rates
ELCC – Effective Load Carrying Capacity
EOI – Expression of Interest
EPC – Engineering, Procurement, and Construction
EV – Electric Vehicle
FEED – Front-End Engineering and Design
GWh – Gigawatt-hour
Haldar – Haldar & Associates, Inc.
IIS – Island Interconnected System
kW – Kilowatt
LIL – Labrador-Island Link
LIS – Labrador Interconnected System
LNG – Liquified Natural Gas
MW – Megawatt
NAP – Network Additions Policy
NERC – North American Electric Reliability Corporation
NL – Newfoundland
NLH – Newfoundland and Labrador Hydro
NLIS – Newfoundland and Labrador Interconnected System
NPCC – Northeast Power Coordinating Council
NPV – Net Present Value
O&M – Operating and Maintenance

PPAs – Power Purchase Agreements
PSSE – Power System Simulator for Engineering
RAP – 2024 Resource Adequacy Plan
RICE – Reciprocating Internal Combustion Engines
RFP – Request for Proposals
RRA – Reliability and Resource Adequacy Report
SCCTs – Simple-Cycle Combustion Turbines
SMR – Small Modular Nuclear Reactors
TOU – Time of Use
TransGrid – TransGrid Solutions
TWh – Terawatt-hour
UBI – Unbalanced Ice
Yr – Year

I. Introduction

Bates White, LLC ("Bates White") appreciates the opportunity to provide comments on Newfoundland and Labrador Hydro's ("NLH's") 2024 Resource Adequacy Plan ("RAP"),[1] which was filed with the Board of Commissioners of Public Utilities ("Board") on July 9, 2024. Bates White was retained by the Board to conduct a review of the RAP and to provide comments for filing with the Board to assist in the review process. The comments presented here fulfill that request.

Importantly, the RAP filing is just one step in NLH's resource planning process. It will be subject to technical conferences and written discovery in the coming weeks and months. Parties do not have access to the level of detailed information that would allow for definitive conclusions regarding NLH's ultimate plans to maintain resource adequacy through 2034. Our review of the RAP is intended to contribute to this process by raising key questions and considerations as NLH, the Board, and stakeholders move forward.[2] Attachment 2 – Bates White's List of Recommended Near-Term RAP Process Action Items lists these key questions and considerations.

II. Overview of RAP Filing

NLH's RAP filing contains several pieces totaling several hundred pages. It contains an overview document,[3] a summary of NLH's planning criteria and study methodology,[4] a summary of the development of resource portfolio expansion plans and the Recommended Portfolio,[5] and technical documents and studies regarding issues including NLH's forced outage rate methodology,[6] existing hydroelectric uprate potential,[7] accelerated combustion turbine ("CT") installation at Holyrood,[8] long-term fuel supply at Holyrood,[9] and impacts of prolonged outages of the Labrador-Island Link transmission asset ("LIL") on Island reservoir levels.[10] The RAP filing also includes three memos from Daymark Energy Advisors ("Daymark") regarding the

---

1 NLH, "2024 Resource Adequacy Plan," July 9, 2024, ("RAP Filing").

2 The RAP Filing often contains pages that have two sets of numbering—one on the top right of the page, one on the bottom right. In the references in our report, we refer to the former.

3 RAP Filing, "2024 Resource Plan Overview" ("Overview").

4 RAP Filing, "Appendix B: Planning Criteria and Study Methodology."

5 RAP Filing, "Appendix C: 2024 Expansion Plans: Development Process and Recommendation."

6 RAP Filing, "Appendix B, Attachment 1: Forced Outage Rate Methodology."

7 RAP Filing, "Appendix C, Attachment 2: 'Uprate Report,' by Hatch Ltd."

8 RAP Filing, "Appendix C, Attachment 3: 'Accelerated Holyrood Combustion Turbine Installation Options Study—Final Report,' by Stantec Consulting Ltd."

9 RAP Filing, "Appendix C, Attachment 4: 'Long-Term Fuel Supply Study, Holyrood,' by Stantec Consulting Ltd."

10 RAP Filing, "Appendix C, Attachment 5: 'Impact of Prolonged Loss of LIL on Island Reservoir Levels,' by Hatch Ltd."

overall process,[11] NLH's firm energy analysis,[12] and the cost assumptions for resource options considered in NLH's expansion planning efforts.[13] Concurrently, NLH also filed a report that responds to certain reports regarding the LIL's operation to date.[14]

The RAP covers the period through 2034 and seeks to "[d]emonstrate the need to construct new generation to provide an adequate supply of electricity due to increasing load growth and reliability of supply" and "[i]dentify the viable supply options for electricity in line with [NLH's] mandate under the [Electrical Power Control Act]."[15] As such, the RAP filing contains a wealth of assumptions, including those regarding electricity demand, viable resource options (and their costs), environmental and policy considerations, electricity rates and their impacts, and the reliability of existing assets, such as the LIL. The RAP filing also considers the standard to which the grid should be considered reliable and assesses the Island Interconnected System ("IIS") separately from the Labrador Interconnected System ("LIS"). The RAP filing identifies several models used in the process, including financial, transmission, and capacity expansion models, and demonstrates the scenarios (using specified combinations of key variable assumptions) and sensitivities (model runs where the value of one or more variables in a given scenario is varied to understand its importance). NLH also provides the results of its models, providing results for approximately 30 expansion model runs.

As an outcome of its planning and modeling efforts, NLH identifies a "Minimum Investment Required" portfolio "under all scenarios regardless of the reliability criteria and pace of load growth."[16] They include (1) construction of a new 154 MW hydroelectric unit (Unit 8) at Bay d'Espoir ("BDE"), (2) construction of a new 150 MW CT resource with renewable fuel capabilities on the Avalon peninsula, and (3) integration of 400 MW installed capacity of wind generation.[17] (We will refer to this as the "Recommended Portfolio.")

NLH provided the RAP as part of its ongoing reliability and resource adequacy ("RRA") efforts initiated in 2018[18] and included evidence of the need for investment in new resources. NLH explains that because "[i]mmediate decisions are necessary to advance the planning, construction, and integration of these new supply resources based on current understanding," it "plans to issue an expression of interest for energy provision in 2025 and is currently proceeding with the planning and engineering of the selection additions to its resource supply," including

---

11 RAP Filing, "Appendix A: 2024 Reliability & Resource Adequacy Process Review."

12 RAP Filing, "Appendix B, Attachment 2: 'Energy Analysis Memo,' Daymark Energy Advisors."

13 RAP Filing, "Appendix C, Attachment 1: 'Resource Cost Comparison,' Daymark Energy Advisors."

14 NLH, "Analysis of Recommendations, Mitigations, and Enhancements of the Labrador-Island Link, Haldar/Labrador-Island Link Investigation Reports," July 9, 2024 ("NLH LIL Report").

15 RAP Filing, Overview, page 2 lines 15 to 19.

16 RAP Filing, Overview, page 46 lines 25 to 26.

17 RAP Filing, Overview, page 45 lines 8 to 11.

18 RAP Filing, Overview, page 1 lines 7 to 9.

BDE Unit 8 and a 150 MW CT on the Avalon.[19] NLH explains too that it "is in the process of preparing evidence for applications for the first of these generation additions."[20] NLH assumes that the regulatory approval process for a new supply resource would take one year[21] and that "any new supply would be seven to ten years away from the date of applications for approval."[22]

Moreover, NLH indicates that the Recommended Portfolio is "insufficient to meet the anticipated demand" (as contained in the IIS base case load forecast, the "Reference Case") "and reliability criteria."[23] NLH recommends continued monitoring of key variables, analysis on least-cost options to satisfy the Reference Case, and biennial RRA update filings to be made with the Board.[24]

III. Bates White Assessment of RAP Filing

A. Load Forecast

A key input to the resource planning process is the load forecast, as it provides the utility's best estimate of expected energy and peak demand over the forecasting time horizon. NLH's load forecast, which is incorporated in the RAP filing, was produced in the third quarter of 2023 and filed with the Board in March 2024 and covers the full forecast period (i.e., through 2034).[25] On July 25, 2024, Bates White provided an assessment of NLH's load forecast report.[26] We have appended our assessment of the load forecast report to this document as

---

19 RAP Filing, Overview, page 47 line 22 to page 48 line 1.

20 RAP Filing, Overview, page 66 lines 9 to 10.

21 RAP Filing, Overview, footnote 132.

22 RAP Filing, Overview, page 65 lines 12 to 13.

23 RAP Filing, Overview, page 47 lines 4 to 5.

24 RAP Filing, Overview, page 64 lines 1 to 15.

25 RAP Filing, Overview, page iv lines 4 to 7.

26 Bates White, "Assessment of Newfoundland and Labrador Hydro's Long-Term Load Forecast – 2023," July 25, 2024.

Attachment 1 – Bates White's July 25, 2024 Assessment of NLH's Load Forecast.

B. Reliability Planning Criteria

NLH's planning objective is to "[satisfy] loss of load criteria while ensuring sufficient resources to meet operational reserves and sufficient resources to meet energy requirements."[27] Thus, in addition to its load forecast, NLH's reliability planning criteria – how much planning reserve capacity to carry above forecasted peak load, how much operational reserves to carry to meet operational contingencies, etc. – are vital inputs. NLH explains that the standards to which it plans the reliability of its system is a mix of "long-standing criteria that have been used to meet system reliability for decades" and "more recent planning criteria…[that] reflect the interconnection to the North American Grid via the Maritime Link and the completion of the LIL that delivers power from Muskrat Falls to the Soldiers Pond [terminal station] on the Avalon."[28] There are several reliability criteria considered by NLH; we address each here.

Regional and subregional planning: In 2018, NLH recommended that planning for its system be on a regional basis (i.e., the entire Newfoundland and Labrador Interconnected System, or "NLIS") and sub-regional basis (i.e., considering the IIS independently).[29] In 2022, NLH committed to reassess its regional and sub-regional planning approach.[30] NLH now proposes to maintain this approach in the RAP, primarily due to the importance of the LIL in serving IIS demand and the elevated bipole equivalent forced outage rates of the LIL.[31] Specifically, the LIL has experienced a bipole equivalent forced outage rate of 2.34% (based on LIL capacity of 700 MW)[32] or 3.56% (based on LIL capacity of 900 MW),[33] considerably higher than the original assumed LIL bipole equivalent forced outage rate of 0.0114%.[34] NLH now assumes the LIL to exhibit an annual bipole equivalent forced outage rate between 1% and 10%, inclusive.[35] (NLH explains that a 1% outage rate equates to approximately four days per year when the LIL is unavailable; a 5% outage rate represents 18 days per year, and a 10% outage rate represents approximately 37 days per year of unavailability.)[36]

On a preliminary basis, NLH does provide evidence of the need for sub-regional planning. The IIS does appear to rely upon generation from Muskrat Falls (delivered to the IIS by the LIL)

---

27 RAP Filing, Appendix B, page 6 lines 7 to 8.

28 RAP Filing, Appendix B, page 6 lines 9 to 12.

29 RAP Filing, Appendix B, page 7 lines 13 to 14.

30 RAP Filing, Appendix B, page 8 lines 3 to 6.

31 RAP Filing, Appendix B, page 7 line 14 to page 8 line 2.

32 RAP Filing, Appendix B, Attachment 1, page 7 line 5.

33 RAP Filing, Appendix B, Attachment 1, page 7 line 6.

34 RAP Filing, Appendix B, page 7 lines 14 to 16.

35 RAP Filing, Appendix B, page 7 line 24.

36 RAP Filing, Appendix B, footnote 64.

for substantial amounts of both capacity and energy, and the bipole equivalent forced outage rate of the LIL has remained two orders of magnitude higher than originally designed, with no evidence at this time suggesting the LIL will revert to the original, low bipole equivalent force outage rate in the foreseeable future. More detail on the modeling outcomes, including total energy deliveries over the LIL to the IIS, would be instructive.

Probabilistic capacity criterion (loss of load): NLH has historically planned its system to experience two outage days in a ten-year period.[37] This translated to a "loss of load expectation," or "LOLE," of 0.2 days per year,[38] and a "loss of load hours" in a year, or "LOLH," of 2.8.[39] In 2022, NLH committed to reassessing its probabilistic capacity criterion, specifically to consider a LOLE that was less than or equal to 0.1 for both the NLIS and the IIS.[40] In the RAP filing, NLH states that the more stringent LOLE of 0.1 "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."[41] NLH notes that "LIL reliability remains a key factor in the ability to economically achieve more stringent planning criteria,"[42] suggesting that the higher-than-expected LIL bipole equivalent forced outage rate is a primary cause of the recommendation to maintain the less stringent 2.8 LOLH standard.

NLH is correct that there is a tradeoff between reliability and cost. That tradeoff requires careful consideration which, in the current circumstances, means a robust review of the reliability impacts and results of future supply and demand conditions. It is important that the Board and stakeholder representatives be included in this consideration, as ultimately it will be NLH customers that pay the required investments to meet the targeted level of reliability.

NLH has provided some evidence of the tradeoffs between system reliability and cost. In all, NLH conducted 30 model runs, though just one of those runs modeled a 0.1 LOLE (as opposed to a 0.2 LOLE/2.8 LOLH, which was modeled in all 29 other runs).[43] That single run (Sensitivity 7AEF) shows a total cost of $6.4 billion in net present value ("NPV") terms. This is more than twice the cost of Sensitivity 4AEF, which uses similar assumptions other than a less stringent reliability criteria (2.8 LOLH) and a lower assumed bipole equivalent forced outage rate for the LIL (1%, vs. 5% in the 7AEF case).[44] To the extent parties are interested in better understanding the impact of planning to a 0.1 LOLE standard, additional model runs may be needed. (NLH did

[37] RAP Filing, Appendix B, footnote 9.

[38] RAP Filing, Appendix B, footnote 9.

[39] RAP Filing, Appendix B, page 6 lines 15 to 16.

[40] RAP Filing, Appendix B, page 8 lines 3 to 10.

[41] RAP Filing, Appendix B, page 10 lines 18 to 22.

[42] RAP Filing, Appendix B, page 11 lines 12 to 13.

[43] RAP Filing, Appendix C, Table 4.

[44] RAP Appendix C, Chart 14.

indicate that in the case of a 5% LIL bipole equivalent forced outage rate, adopting a 0.1 LOLE would require an additional 135 MW of firm capacity to meet reserve margin requirements.)[45]

It may be that the cost of higher reliability (via a 0.1 LOLE, which is commonly used in North America[46]) will remain prohibitively expensive so long as the LIL's forced outage rate remains high. This would be an unfortunate outcome, but NLH and stakeholders need to focus on the reality of the system as it currently stands and as it is expected to be for the planning horizon, and to base investment decisions on that reality. To that end, NLH's LIL shortfall assessment is a useful exercise, which we address below.

Firm energy requirements: NLH has also historically planned its system to have "sufficient generating capability to supply all its firm energy requirements with firm system capability."[47] As with the other reliability criteria above, NLH committed in 2022 to reassessing this approach.[48] In the RAP filing, NLH retained this approach. It does not appear that NLH considered or modeled any other approach. In discussing how it conducted its firm energy analysis, NLH stated:

> …it is now confirmed that the amount of energy that can flow over the LIL to the Island is limited by the interdependencies with the Maritime Link and Island load. This interdependence exists both because both HVDC links must work together using [remedial action schemes] that will suddenly reduce their power flows (runbacks) to transiently regulate system frequency in the event a contingency occurs on the other HVDC link, resulting in the further requirement to consider the firm energy requirement of the two regions independently. Therefore, for this filing, the Island and Labrador Interconnected Systems have been assessed separately, with the LIL considered as a firm energy resource to the Island.[49]

This suggests (and it logically follows) that the LIL's reliability impacts NLH's ability to meet its firm energy requirements as well as reliability. As we explain below, NLH's capacity expansion modeling approach was to manually insert (i.e., specify "fixed") energy resource additions to ensure firm energy requirements were met,[50] and thus this requirement was met in all affected modeling runs. We address the modeling results in Section III.G below.

Operational capacity requirements: In the RAP filing, NLH proposes to meet certain operational reliability standards as specified by the Northeast Power Coordinating Council ("NPCC"),[51] its "Regional Entity" under the North American Electric Reliability Corporation

45 RAP Appendix B, Table 11.

46 EPRI, "Resource Adequacy Practices and Standards," available at: https://msites.epri.com/resource-adequacy/metrics/practices-and-standards.

47 RAP Filing, Appendix B, page 44 lines 19 to 21.

48 RAP Filing, Appendix B, page 8 lines 3 to 12.

49 RAP Filing, Appendix B, page 46 lines 6 to 13.

50 RAP Filing, Appendix C, page 100 lines 5 to 7.

51 RAP Filing, Appendix B, page 12 lines 11 to 14.

(“NERC”). Specifically, NLH proposes to hold enough ten-minute reserve to meet the loss of its single largest contingency (206 MW)[52] and enough thirty-minute reserve to meet 50% of the loss of its second largest contingency (103 MW[53]).[54]

NLH states that “it remains economically feasible” to meet these NPCC criteria.[55] We did not observe any model runs or sensitivities where these NPCC operational constraints were not enforced, so it is difficult to assess NLH’s statement about economic feasibility. We note that the NPCC criteria are widely adopted industry standards and are designed to keep systems reliable in the short run.

In one of its memos included in the RAP filing, Daymark states that NLH’s “excluding the loss of the LIL as the largest single contingency on the [NLIS] merits further review, especially considering the absence of any meaningful operational history for the LIL.”[56] Daymark notes that because a LIL tower failure or software failure can result in a complete bipole outage, indicating the LIL may better be considered as “energy only and not as firm capacity or the equivalent of on-island capacity as is currently the case.”[57] The implications for treating the LIL as the single largest contingency (700 MW, currently, 900 MW as designed) would be significant, as would treating the LIL as energy-only. NLH conducted a model run where the LIL provides no capacity benefit, the resulting cost of the required resource portfolio is $8.2 billion.[58] Nevertheless, Daymark’s point is highly relevant: 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). We agree this is an issue that should be explored in this proceeding, recognizing, as Daymark expressly does, that planning for this larger contingency would have cost consequences.[59]

LIL shortfall criteria: NLH conducted an assessment of a prolonged bipole outage of the LIL during winter conditions on each portfolio of resources selected in all 30 reported model runs. This assessment “is intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line” but “could generally apply to any prolonged outage

---

[52] NLH’s single largest contingency is a generating unit at Muskrat Falls, which is 206 MW. RAP Filing, Appendix B, page 12 line 19 to page 13 line 3.

[53] NLH’s second largest contingency is a second generating unit at Muskrat Falls, which is 206 MW. RAP, Appendix B, page 13 lines 4 to 6.

[54] RAP Filing, Appendix B, page 12 lines 15 to 18.

[55] RAP Filing, Appendix B page 12 line 13.

[56] RAP Filing, Appendix A, page 9.

[57] RAP Filing, Appendix A, pages 9 to 10.

[58] RAP Filing, Appendix C, page 95 line 14.

[59] RAP Filing, Appendix A, page 10.

event."[60] As such, NLH's approach was to specify a six-week long outage at the coldest period of the year (January 1 through February 15).[61]

NLH's recognition of the potential for an extended outage on the LIL and plan for such a possibility is sensible and necessary. As NLH notes, there is no specified planning criteria it can rely upon for conducting this analysis.[62] The specifics of the LIL shortfall analysis – peak winter, six weeks in outage duration – are worth considering to determine if NLH's analysis is a reasonable representation of the risk of a LIL bipole outage. The analysis included other assumptions worth vetting, including the halting of deliveries of Nova Scotia Block quantities over the Maritime Link, up to 50 MW of Corner Brook Pulp and Paper ("CBPP") capacity assistance "for an extended duration," and a small reduction in Vale Newfoundland and Labrador Limited ("Vale") customer generation.[63] Each of these additional assumptions lessens the negative reliability impact of a prolonged LIL bipole outage and should, along with other yet-to-be-identified mitigants, be further considered in this proceeding.

Planning reserve margin results: Ultimately, key reliability inputs such as the 2.8 LOLH/0.2 LOLE probabilistic planning criteria (measured in outage hours) and the assumed LIL bipole equivalent forced outage rate (measured in percentages) must be translated into actual resource needs (in terms of firm capacity, measured in MW). The "planning reserve margin" is the amount of firm capacity above forecasted peak load needed to keep the system reliable. The size of NLH's planning reserve margin, measured in MW, gets larger as reliability criteria get more stringent and the assumed forced outage rate on the LIL increases. Thus, across all scenarios and sensitivities, NLH's planning reserve margin ranges from as low as 360 MW to as high as 675 MW; as a percentage of peak load, these planning reserve margins varied from as low as 17.1% to as high as 35.1%.[64]

NLH demonstrated the materiality of the assumptions of the LOLE/LOLH and LIL outage assumptions on the planning reserve margin. Switching to a 0.1 LOLE would mean a 35.1% planning reserve margin and the need for an additional 135 MW in planning reserves (assuming a 5% LIL bipole forced outage rate).[65] Meanwhile, assuming a 10% LIL forced outage rate (while maintaining the 2.8 LOLH criteria) would require a reserve margin of 29.1% and an additional 190 MW of planning reserve capacity relative to a 1% LIL forced outage rate.[66]

---

[60] RAP Filing, Appendix B, page 12 lines 4 to 6.

[61] RAP Filing, Appendix B, page 38 lines 14 to 15.

[62] RAP Filing, Appendix B, page 12 lines 7 to 9.

[63] RAP Filing, Appendix B, page 38 line 16 to page 39 line 5. Vale, an operator of mining and processing facilities in the province, is a curtailable load customer with on-site, diesel-fired generation.

[64] RAP Filing, Appendix B, Table 10.

[65] RAP Filing, Appendix B, Table 10.

[66] RAP Filing, Appendix B, Table 10.

Specification of the reliability criteria is a crucial exercise, as it directly (and materially) impacts the amount of capacity needed to meet the resultant planning reserve margin requirements. For reference, most North American utilities set planning reserve margins between 10% and 25%, including the NPCC entities.[67] NLH, in its Recommended Portfolio, has set a planning reserve margin of 17.1%.[68] This, along with the reliability assumptions above, should be well vetted in this proceeding.

C. Existing Generation and Transmission

Another key consideration in any electric utility resource adequacy and reliability assessment is the treatment, modeling, and forecasted expectations regarding those assets that currently serve customer needs, including generation and transmission assets. This section reviews the RAP filing's treatment of existing generation and transmission assets.

As an initial matter, a complete review of NLH's assumptions and modeling of its existing assets requires additional data and information from NLH. While NLH provided a summary of some elements of its treatment of its existing assets, not all details are included. We expect this will occur in the coming weeks as the review proceeds. Below, we provide discussion of some of the key considerations of the RAP's treatment of NLH's existing assets.

1. Generation Supply

The electric power generation resources of Newfoundland and Labrador are predominantly hydroelectric with an estimated total generating capacity of 8,280 megawatts (MW). Most of the electric energy in the province is produced at the hydroelectric facilities at Churchill Falls and Muskrat Falls in Labrador and Bay d'Espoir in Newfoundland.[69] The rest of the electric energy is produced by heavy oil fired and diesel thermal, wind and biomass generating units.

In Labrador, the energy generated is primarily hydroelectric, with the Happy Valley Goose Bay gas turbine as a source of back up energy for the Happy Valley area, and 13 diesel generators serving isolated systems along its Northeast coast. Table 1 lists the names of the generators in Labrador and the respective energy source.

---

[67] NERC, "2024 Summer Reliability Assessment May 2024," Figure 4, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

[68] RAP Filing, Appendix C, Table 4.

[69] Atlantica Centre for Energy, "Newfoundland and Labrador's Energy Resources," available at: https://www.atlanticaenergy.org/energy-knowledge-centre/energy-maps/newfoundland-and-labradors-energy-resources/.

Table 1: Generating Facilities in Labrador[70]

Labrador	
Hydroelectric	MW
Churchill Falls Hydroelectric Generating Facility	5,428.0
Muskrat Falls Hydroelectric Generating Facility	824.0
Menihek Hydroelectric Generating Station	18.0
Mary's Harbour Renewables Project	0.2
Total	**6,270.2**
Diesel	
L'Anse au Loup Diesel Generating Station	8.0
Mary's Harbour Diesel Generating Station	2.5
Happy Valley Goose Bay Gas Turbine	25.0
St. Lewis Diesel Generating Station	1.0
Port Hope Simpson Diesel Generating Station	2.3
Charlottetown Diesel Generating Station	2.5
Norman's Bay Diesel Generating Station	0.2
Black Tickle Diesel Generating Station	1.0
Cartwright Diesel Generating Station	2.5
Paradise River Diesel Generating Station	0.2
Rigolet Diesel Generating Station	1.3
Makkovik Diesel Generating Station	2.0
Postville Diesel Generating Station	1.0
Hopedale Diesel Generating Station	2.6
Natuashish Diesel Generating Station	4.3
Nain Diesel Generating Station	3.9
Total	**60.2**
Solar	
Mary's Harbour Renewables Project	0.2
Nunatsiavut Community Solar Projects	0.1
Total	**0.3**

Existing resources that supply the LIS capacity requirements are sufficient to meet the Reference Case requirements; however, additional capacity resources would be required to meet the industrial Medium and High Growth requirements that have been identified through the Network Additions Policy ("NAP") process. Reserves are not required since generation is deemed highly reliable.

In Newfoundland, 68 percent of the generating capacity is hydroelectric, while the remainder is served by heavy oil-fired Holyrood (23 percent), diesel generating units (5 percent), wind (3

[70] Atlantica Centre for Energy, "Newfoundland and Labrador's Energy Resources," available at: https://www.atlanticaenergy.org/energy-knowledge-centre/energy-maps/newfoundland-and-labradors-energy-resources/.

percent), and biomass (1 percent).[71] Table 2 lists the generating facilities located in Newfoundland.

[71] Figures derived from data available from: Atlantica Centre for Energy, "Newfoundland and Labrador's Energy Resources," available at: https://www.atlanticaenergy.org/energy-knowledge-centre/energy-maps/newfoundland-and-labradors-energy-resources/.

Table 2: Generating Facilities in Newfoundland[72]

Newfoundland			
Hydroelectric	MW	***Steam Cycle***	MW
Roddickton Hydro Plant	0.4	Holyrood Thermal Generating Station	490.0
Cat Arm Hydroelectric Generating Station	127.0	***Diesel***	
Rattle Brook Hydroelectric Generating Station	15.1	Ramea Wind-Diesel Energy Project	3.2
Snooks Arm and Venams Bight	1.0	Stephenville Diesel Generating Station	50.0
Deer Lake Hydroelectric Generating Station Lake	126.0	Grey River Diesel Generating Station	0.5
Watsons Brook Hydroelectric Generating Station	9.0	Francois Diesel Generating Station	0.6
Hinds Lake Hydroelectric Generating Station	75.0	McCallum Diesel Generating Station	0.4
Buchan's Hydroelectric Generating Station – Exploit River System	91.2	Hardwoods Diesel Generating Station	50.0
Star Lake Hydroelectric Generating Station	18.4	St. Brendan's Diesel Generating Station	0.7
Lookout Brook Hydroelectric Power Station	6.2	St. Anthony Diesel Generating Station	9.7
Rose Blanche Brook Hydroelectric Power Generating Plant	6.0	**Total**	**115.2**
Granite Canal Hydroelectric Generating Station	41.0	***Wind***	
Upper Salmon Hydroelectric Generating Station	84.0	Ramea Wind-Diesel Energy Project	3.2
Bay d'Espoir Hydroelectric Generating Facility	604.0	St. Lawrence Wind Farm	27.0
Paradise River Hydroelectric Generating Station	8.0	Fermeuse Wind Turbine Power Project	27.0
Sandy Brook Hydroelectric Generating Station	5.5	**Total**	**57.2**
Grand Falls Hydroelectric Generating Station – Exploit River System	91.2	***Biomass***	
Bishop's Falls Hydroelectric Generating Station – Exploit River System	91.2	Corner Brook Biomass Cogeneration Plant	17.6
Norris Arm Rattling Brook Hydroelectric Generating Station	12.5		
Lockston Hydroelectric Generating Station	3.0		
New Chelsea Hydroelectric Generating Station	3.7		
Heart's Content Hydroelectric Generating Station	3.5		
Seal Cove Hydroelectric Generating Station	3.5		
Topsail Hydroelectric Generating Station	2.6		
Petty Harbour Hydroelectric Generating Station	4.9		
Pierre's Brook Hydroelectric Generating Station	4.3		
Tors Cove Hydroelectric Generating Station	6.9		
Cape Broyle Hydroelectric Generating Station	6.3		
Mobile Hydroelectric Generating Station	12.0		
Morris Hydroelectric Generating Station	1.1		
Rocky Pond Hydroelectric Generating Station	3.3		
Horse Chops Hydroelectric Generating Station	8.3		
Total	**1,476.1**		

Some of the assets in Table 2 are reaching the end of their economic lives. Consistent across all load forecast scenarios, once the Holyrood TGS, Hardwoods GT, and Stephenville GT retire

[72] Atlantica Centre for Energy, "Newfoundland and Labrador's Energy Resources," available at: https://www.atlanticaenergy.org/energy-knowledge-centre/energy-maps/newfoundland-and-labradors-energy-resources/.

in 2030, the Island Interconnected System will no longer meet its reliability criteria without generation expansion. Additionally Bay d'Espoir Unit 7 will require an overhaul in the near future due to its age and condition. We address issues relating to existing generation assets in the RAP filing here.

Firm capacity assumptions for existing generating assets: For most of its hydro resources, NLH assumes a firm capacity (in MW) that equals the respective units' installed capacity.[73] NLH explains that such units either have large storage capacities (e.g., Bay d'Espoir, Cat Arm, Hinds Lake, and Star Lake) or operate within large overall storage systems (e.g., Granite Canal and Upper Salmon).[74] For the Exploits system, which has large storage capacity, NLH adjusts the firm capacity down from 94.2 MW to 63.0 MW to account for seasonal impacts of frazil icing, to which NLH explains Exploits is susceptible.[75] Other hydro resources with limited storage or no storage (i.e., run-of-river resources), including Newfoundland Power's resources, are adjusted downward as well[76] (e.g., Newfoundland Power's 94.2 MW of resources contribute 60.1 MW of firm capacity.)[77] These assumptions appear supported, though may be subject to discovery and discussion in the ongoing RAP process.

NLH assumes Muskrat Falls' firm capacity contribution equals 100 percent of its rated capacity of 824 MW.[78] NLH noted that prior estimates of Muskrat Falls' firm capacity identified a potential limit of 790 MW due to tailrace icing, but as NLH has not observed this phenomenon in operation since Muskrat Falls' commissioning, NLH did not apply this limit to NLH's modeled firm capacity.[79] This assumption also appears supported.

For its thermal generating units, NLH assumes a firm capacity that equals installed capacity in all instances but one. Specifically, the Holyrood diesel units face "environmental restrictions" that NLH modeled via an hourly capacity restriction.[80] This results in a small (4 MW) reduction to these units.[81] These assumptions also appear supported.

NLH's wind resources, which total 54 MW of installed capacity, are assumed to contribute 12 MW of firm capacity.[82] NLH applies an effective load carrying capability ("ELCC") of 22

---

[73] RAP Filing, Appendix B, Table 2.

[74] RAP Filing, Appendix B, page 26 lines 17 to 18. It should be noted that Cat Arm units 1 and 2 are modeled at 67.0 MW of firm capacity, rather than their installed capacity of 68.5 MW.

[75] RAP Filing, Appendix B, page 26 lines 20 to 21; Table 2.

[76] RAP Filing, Appendix B, page 26 lines 25 to 26.

[77] RAP Filing, Appendix B, Table 2.

[78] RAP Filing, Appendix B, Table 3.

[79] RAP Filing, Appendix B, page 27 lines 4 to 13.

[80] RAP Filing, Appendix B, page 29 lines 2 to 7.

[81] RAP Filing, Appendix B, Table 4.

[82] RAP Filing, Appendix B, Table 6.

percent to existing wind, which is based on an ELCC study completed in November of 2019.[83] We address wind ELCCs in section III.D below.

Timing, cost of Holyrood retirement: The Holyrood generating station consists of three oil-fired generating units, each between 45 and 53 years old, with a combined installed capacity of 490 MW.[84] In the RAP, NLH recommends continued investment in the Holyrood TGS (and other thermal resources, addressed below in the discussion of the "Bridging Period").[85] NLH explains that the units cannot operate past 2034, as they would not be in compliance with the province's *Clean Electricity Regulations*, or CER.[86] The RAP filing assumes a retirement date for Holyrood of 2030.[87]

The RAP filing does not provide detailed cost information for the Holyrood units through 2030. NLH notes that it "considered a third-party condition assessment conducted by Hatch,"[88] which contains the following cost estimates for maintaining the Holyrood units through 2030.

- To operate the units as emergency backup generation (units 1, 2) and synchronous condenser mode (unit 3), the cost estimates ranged between $566.2 million and $612.3 million.[89]
- The cost estimate for continued operation of the units through 2030 (producing four months out of the year at an average per-unit load of 77-94 MW) was $1,325.5 million, driven by higher fuel costs associated with greater generation output.[90]

NLH's modeling and assumptions regarding the operation and costs of the Holyrood units through 2030 requires further review and explanation.

NLH also notes that it has "engaged a consultant to complete a refresh of the capital plan" for Holyrood "to assess the cost and viability of operation of Holyrood TGS beyond 2030, to inform supply options in the event that some supply from Holyrood TGS is needed in advance of new generation."[91] This may be a worthwhile exercise; however, NLH should also justify the assumed sustaining of the Holyrood units through 2030. In fact, all 30 reported expansion model runs assumed retirement of Holyrood in 2030. It would be useful to test earlier retirement dates for one or more Holyrood units, with new supply reaching commercial operations prior to 2030. NLH appears to justify the timing of the new resources assumed online dates (and Holyrood

83 RAP Filing, Appendix B, page 31 lines 20 to 22.
84 RAP Filing, Overview, page 17 lines 9 to 11.
85 RAP Filing, Overview, page 17 lines 14 to 15.
86 RAP Filing, Overview, page 17 line 20.
87 RAP Filing, Overview, page 24 lines 24 to 25.
88 RAP Filing, Overview. page 24 lines 17 to 18.
89 Hatch Ltd., "HTGS Condition Assessment and Life Extension Study," 2022, Table 1-7.
90 Hatch Ltd., "HTGS Condition Assessment and Life Extension Study," 2022, Table 1-9.
91 RAP Filing, Overview, page 24 line 24 to page 25 line 3.

retirement dates) by its assumption that "any new supply would be seven to ten years away from the date of applications for [regulatory] approval."[92] This assumption must also be further supported, particularly if it is the basis for sustaining all of NLH's existing generation assets through 2030.

That said, NLH's consideration of Holyrood as an asset beyond 2030 also requires review and consideration. It appears NLH did not model Holyrood beyond 2030 but modeled its retirement in 2030 in all cases.[93] If Holyrood is a viable option beyond 2030, it would be helpful to have an estimate of the costs and impacts of retaining one or all of the Holyrood units. NLH should also clarify the timing of Holyrood's retirement, which would not necessarily coincide perfectly with the commissioning of new (replacement) generation. NLH modeled Holyrood to retire concurrently with the commissioning of new generation supply. If so, this may understate total costs, as utilities typically time generation retirements with non-peak seasons and/or wait to retire generation until the new supply resources have achieved some period of successful operation. NLH acknowledged this issue in its filing.[94]

"Bridging Period" and Generation Retirements: In addition to sustaining the Holyrood units, NLH also proposes to maintain the Hardwoods GT and Stephenville GT through an April 1, 2030 retirement date; NLH is also assuming 2030 as the anticipated retirement date for Newfoundland Power's Greenhill GT and Wesleyville GT.[95] Collectively, these resources total 618 MW of firm capacity, 590 MW of which is owned by NLH.[96] NLH explains that maintaining these resources is needed during the "Bridging Period," which lasts through 2030, whereby NLH "would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built."[97] As with the Holyrood units (discussed above), all 30 model runs assume these generation resources retire in 2030, and thus it may be useful to test earlier retirement dates for one or more Holyrood units. The sustaining capital and operating and maintenance ("O&M") costs of these units should also be clarified.

Generation forced outage rates: For its existing thermal assets, NLH used a mix of historical derated adjusted forced outage rates ("DAFORs"), historical derated adjusted utilization forced outage probability ("DAUFOPs"), and equivalent forced outage rates ("EFORd") reflected in NERC reports.[98] For Holyrood thermal generating station, NLH proposed to use DAUFOP as the metric and a value of 20% in the base case and a sensitivity of

92 RAP Filing, Overview, page 65 lines 12 to 13.
93 RAP Filing, Overview, page 24 lines 24 to 25.
94 RAP Filing, Appendix B, page 41 lines 14 to 16.
95 RAP Filing, Appendix B, Table 8.
96 RAP Filing, Appendix B, Table 8.
97 RAP Filing, Appendix B, page 40 lines 24 to 28.
98 RAP Filing, Appendix B, Attachment 1, page 3 lines 12 to 16.

34% for "near-term planning."[99] For NLH's CTs, NLH used a mix of approaches to derive the DAUFOP values for use in the "near-term analysis" and Resource Planning Model.[100] For third-party resources, NLH used industry data (e.g., NERC GADS data) to determine DAFOR and DAUFOP, depending on the unit's generating characteristics,[101] and for hydro resources, used industry averages.[102] For its hydro units, NLH used a three-year capacity-weighted average DAFOR for the "near-term analysis," but a ten-year capacity-weighted average DAFOR for the Resource Planning Model.[103] For the Muskrat Falls project, NLH used historical forced outage rates observed to date for the near-term analysis, and for the Resource Planning Model, used forced outage rates of the NLH-owned hydro resources under the assumption that Muskrat Falls will be maintained to the same standards as the rest of the fleet.[104]

We make a few observations about these assumptions. First, for clarity, NLH should specify in this proceeding the distinction between "near" term and long-term planning. Second, NLH should explain how near-term planning assumptions impact its expansion planning process, modeling, and Recommended Portfolio, if at all. Third, it appears that NLH's near-term sensitivity analysis generally uses higher forced outage rates than those used in the Resource Planning Model.[105] While we recognize NLH's point that its near-term analysis uses more recent forced outage rates for a given unit or units, it is not clear to us that over the long-term, resource forced outage rates will revert to historical norms. This is particularly true for older assets, which are more likely to suffer declines in performance as retirement dates approach. It may be worth considering sensitivity analyses in the Resource Planning Model using higher forced outage rates, particularly for generating assets such as Holyrood, which experienced a 34% DAUFOP in the winter 2021-2022 period.[106] Fourth, NLH should 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. For example, greater number of starts and increased cycling of a generating unit can drive higher forced outage rates, which can be mitigated by higher sustaining capital expenditures. It is not clear from the RAP filing how NLH addressed this relationship or the assumptions made to model the expected use of the thermal resources.

---

99 RAP Filing, Appendix B, Attachment 1, section 4.0.

100 RAP Filing, Appendix B, Attachment 1, section 5.0.

101 RAP Filing, Appendix B, Attachment 1, page 3 lines 17 to 19.

102 RAP Filing, Appendix B, Attachment 1, page 6 lines 3 to 6.

103 RAP Filing, Appendix B, Attachment 1, page 5 lines 2 to 4.

104 RAP Filing, Appendix B, Attachment 1, page 5 line 13 to page 6 line 2.

105 RAP Filing, Appendix B, Attachment 1, Table 1.

106 NLH, "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended June 30, 2024," footnote 8.

2. Transmission

The NLIS Transmission System consists of the Primary Transmission System, Local Networks and a Radial Network. The Local Networks and the Radial Network allow for the delivery of electricity to specific customers under specific customer reliability and cost requirements, such that the Transmission Planning Criteria used for the Primary Transmission System are not strictly applied.

The Primary Transmission System includes all transmission elements within the LIS and IIS with a voltage rating greater than or equal to 230 kV.[107] The Labrador Interconnected System consists of two 315 kV transmission lines between Churchill Falls Terminal Station #2 and Muskrat Falls Terminal Station #2; designated as L3101 and L3102 respectively.[108] The LIS is shown in Figure 1.

Figure 1: Labrador Interconnected System[109]

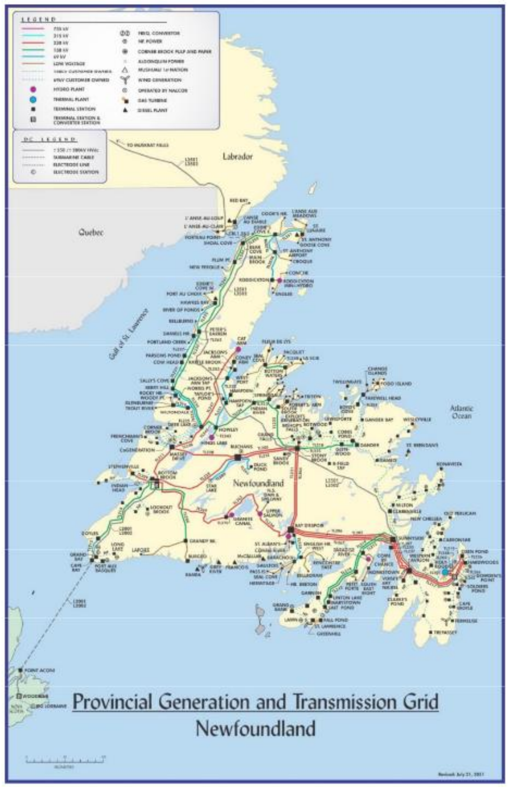
The IIS includes several interconnected systems. The IIS is shown in Figure 2.

[107] NLH, "NLSO Report - 2022 Annual Planning Assessment," March 3, 2022, page 9, ("NLSO 2022 Annual Planning Assessment").

[108] NLSO 2022 Annual Planning Assessment, page 11.

[109] NLSO 2022 Annual Planning Assessment, Appendix A, Figure 2.

Figure 2: Island Interconnected System[110]



The Bay d'Espoir System consists of a network of 230 kV transmission lines between: Bay d'Espoir Terminal Station #2 and Upper Salmon Terminal Station (designated TL234); Upper Salmon Terminal Station and Granite Canal Terminal Station (TL263); and between Granite Canal Terminal Station and Bottom Brook Terminal Station #2 (TL269).[111] This network also includes hydraulic generating facilities at Bay d'Espoir, Upper Salmon and Granite Canal Generation Stations. The Bay d'Espoir Generation Station is the largest plant on the Island Interconnected System with a total capacity of approximately 613 MW. The largest unit at the Bay d'Espoir Generation Station is Unit #7 (154.4 MW), which can also operate as a synchronous condenser.[112] With the addition of the proposed Unit #8 (154.4 MW)[113] the upgrading the total capacity of Bay d'Espoir would reach approximately 767 MW. This network also includes a 15 MVAR reactor at Granite Canal Tap Terminal Station.[114]

---

110 NLSO 2022 Annual Planning Assessment, Appendix A, Figure 2.

111 NLSO 2022 Annual Planning Assessment, page 9.

112 NLSO 2022 Annual Planning Assessment, page 9.

113 RAP Filing, Appendix C, Table 1.

114 NLSO 2022 Annual Planning Assessment, page 9.

Bay d’Espoir Western Avalon Corridor: Bay d’Espoir Terminal Station is interconnected to Western Avalon Terminal station through a network of 230 kV transmission lines between: Bay d’Espoir Terminal Station #1 and Sunnyside Terminal Station (TL202); Bay d’Espoir Terminal Station #2 and Sunnyside Terminal Station (TL206); Bay d’Espoir Terminal Station #2 and Western Avalon Terminal Station (TL267); Sunnyside Terminal Station and Western Avalon Terminal Station (TL203); Sunnyside Terminal Station and Come by Chance Terminal Station (TL207); and between Come by Chance Terminal Station and Western Avalon Terminal Station (TL237). This network also includes four 38.45 MVAR capacitor banks at Come by Chance Terminal Station.[115]

The Western Island Interconnected System consists of a network of 230 kV transmission lines between: Bay d'Espoir Terminal Station #1 and Stony Brook Terminal Station (TL204); Bay d'Espoir Terminal Station #2 and Stony Brook Terminal Station (TL231); Stony Brook Terminal Station and Buchans Terminal Station (TL205 & TL232); Buchans Terminal Station and Bottom Brook Terminal Station #2 (TL233); Bottom Brook Terminal Station #2 and Massey Drive Terminal Station (TL211); Buchans Terminal Station and Massey Drive Terminal Station (TL228); Massey Drive Terminal Station and Deer Lake Terminal Station (TL248); and between Deer Lake Terminal Station and Cat Arm Terminal Station (TL247). This network also includes three hydro generating facilities, Cat Arm, Hinds Lake and Deer Lake Generation Stations. The two units at the Cat Arm Generating Station can also operate in synchronous condenser mode.[116]

The Exploits System only includes the 230 kV line from Stony Brook Terminal Station to the Grand Falls Terminal Station (TL235).[117]

NLH’s transmission system also includes two HVdc lines. First is the LIL, an HVdc bipole that electrically connects the IIS and the LIS, and which terminates at the Muskrat Falls Converter Station and the Soldiers Pond Converter Station.[118] Second is the Maritime Link, which is an HVDC bipole that electrically connects the IIS to Nova Scotia via two 170 km subsea cables. The Maritime Link terminates at Bottom Brook Terminal Station #2 in Newfoundland and at Woodbine Terminal Station in Nova Scotia.[119] Below, we address issues related to NLH’s transmission assets in its RAP filing.

LIL bipole equivalent forced outage rates: As explained earlier in this report, NLH’s experience with the LIL since commissioning has been that of higher-than-expected equivalent forced outage rates. Originally, NLH expected and planned its system assuming a bipole

115 NLSO 2022 Annual Planning Assessment, pages 9 to 10.
116 NLSO 2022 Annual Planning Assessment, page 11.
117 NLSO 2022 Annual Planning Assessment, page 11.
118 NLSO 2022 Annual Planning Assessment, page 12.
119 NLSO 2022 Annual Planning Assessment, page 14.

equivalent forced outage rate of 0.0114%.[120] However, the LIL's actual equivalent forced outage rate has been much higher, averaging 2.34% (based on LIL capacity of 700 MW)[121] or 3.56% (based on LIL capacity of 900 MW).[122] Going forward, NLH assumes the LIL to exhibit a bipole equivalent forced outage rate between 1% and 10%, inclusive.[123]

In the RAP filing, NLH estimated a range of equivalent forced outage rates, which measures the percentage of time that the LIL bipole is unable to deliver its Maximum Continuous Rating (currently 700 MW but designed to be 900 MW[124]) to the Island due to bipole forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping monopole outages (effectively creating a bipole outage).[125] NLH applied a base case bipole forced outage assumption of 5%, with sensitivities of 1% and 10%.[126]

The history of assessments of the LIL's operations – and the studies and reports conducted to address its underperformance – is already substantial. A report by Haldar & Associates, Inc. ("Haldar") in March 2021[127] assessed the impact of glaze and rime icing[128] on the structural reliability of the LIL.[129] The Haldar Report found that the annual expected probability of failure of the LIL can range from about 1% to 5%,[130] with that number likely to increase in certain scenarios and with further assessment of the LIL.[131] NLH has conducted multiple investigations into incidents experienced on the LIL to date and has provided details to the Board about the causes and impacts of those incidents, as well as steps to take to prevent or mitigate those incidents going forward.[132] For example, issues associated with line galloping led to NLH initiating a process to replace approximately 1,300 turnbuckles identified as risks.[133]

Given the observed forced outage rates, the conclusions of the Haldar Report, and NLH's reports on the performance of the LIL to date, it appears reasonable to model a broad range of

120 RAP Filing, Appendix B, page 7 lines 14 to 16.

121 RAP Filing, Appendix B, Attachment 1, page 7 line 5.

122 RAP Filing, Appendix B, Attachment 1, page 7 line 6.

123 RAP Filing, Appendix B, page 7 line 24.

124 The LIL has not yet been commissioned to its full 900 MW rating due to issues related to LIL software. NLH states that it expects such commissioning to occur in the third quarter of 2024. NLH LIL Report, page 4 lines 1 to 7.

125 RAP Filing, Appendix B, Attachment 1, page 6 line 22 to page 7 line 2.

126 RAP Filing, Appendix B, Attachment 1, page 6 lines 16 to 17.

127 Haldar & Associates, Inc., "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," as revised April 11, 2021 ("Haldar Report").

128 Glaze icing is due to freezing precipitation; rime icing is due to in-cloud precipitation.

129 Haldar Report, page ii.

130 Haldar Report, page ii.

131 Haldar Report, page iv.

132 NLH LIL Report, Table 1.

133 NLH LIL Report, page 4 lines 11 to 13. Hydro notes that it replaced 340, or 26% of "all turnbuckles identified for replacement," suggesting a total of approximately 1,300 which have been designated for replacement.

bipole equivalent forced outage rates for the LIL. This is particularly important due to the substantial impact a LIL outage has on IIS reliability once the Holyrood units are retired. NLH's LIL outage sensitivity test, in which each expansion plan resource portfolio was tested against a six-week, peak winter outage of the LIL, is another important planning exercise by NLH. (We address the LIL outage test later in this report.)

The Haldar Report (and a subsequent report filed in December 2021)[134] contained a number of recommendations. NLH has addressed some of these in its RAP Filing[135] and is in the process of addressing others.[136] While many of the steps taken by NLH appear to be addressing Haldar's recommendations and should provide some benefits, it is not always clear to us that NLH is assessing the projected costs and benefits of mitigating investments to improve LIL performance in its RAP expansion planning. For example, Haldar identified a specific section of the LIL – "section 3A" in southern Labrador – that it believed was concerning due to observed climatology in the area inconsistent with the design of section 3A for relatively low wind and ice loads, resulting in section 3A being "more susceptible to issues than in other regions."[137] Haldar recommended that NLH "[a]ssess the mitigation option of upgrading the capacities of several towers in Section 3A, either by redesigning the A1 tower or by installing mid-span towers to upgrade the line in Section 3A and the other sections where similar problems may be encountered."[138]

NLH's response to this recommendation refers to its enhanced efforts to monitor and remove ice from LIL components and its ongoing study of additional bracing to strengthen the capacity of the cross arm to protect against failure caused by unbalanced ice ("UBI") accumulation.[139] NLH states that it has installed enhanced real-time ice monitoring system on a test span of the LIL, with three more locations planned beginning in 2025, as well as a new weather station, increased helicopter patrols (six per year, four in winter), NLH weather preparedness meetings in advance of storms, standardized ice date reporting protocols, and employee training.[140] NLH explains that it is undertaking an engineering assessment to evaluate bracing solutions, after which a third-party cost estimate would be developed with an expected completion date in the fourth quarter of 2024.[141]

Investments such as the buttressing of vulnerable sections of the LIL (such as section 3A) must demonstrate some benefit in light of their costs, and then must be weighed against

---

134 NLH LIL Report, page 1 lines 17 to 18.

135 See, for example, NLH LIL Report, Appendix A, sections 3.1.1, 3.1.3, 3.1.5, 3.1.6, 3.1.7, and 3.1.8.

136 See, for example, NLH LIL Report, Appendix A, sections 3.1.2, 3.1.4, 3.2.1, 3.2.2, 3.2.3, 3.2.4, and 3.2.5.

137 NLH LIL Report, page A-18 lines 19 to 21.

138 NLH LIL Report, page A-18 lines 22 to 24.

139 NLH LIL Report, page A-19 lines 1 to 5.

140 NLH LIL Report, Appendix A, section 2.1.1.

141 NLH LIL Report, Appendix A, section 2.1.2.

alternatives (such as generation supply investments). Here, NLH does not yet have the estimated cost of the LIL mitigation investments, nor the expected benefits. This makes any comparison against the generation alternatives being recommended by NLH in this RAP filing impossible. NLH should continue to address all Haldar recommendations (and those in its 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.

On-Avalon transmission constraint: In May 2023, NLH 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.[142] The study identified certain operational constraints on the Avalon 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.[143] The study also 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).[144] NLH explained that it captured the on-Avalon transmission constraints in its transmission planning model.[145] Moreover, NLH assessed the estimated cost and impact of some of the identified transmission-based solutions put forth by TransGrid.[146] We address NLH's consideration of the transmission-based solutions later in this report.

D. Supply Resource Options

NLH identifies several potential resource expansion options considered in its expansion plan modeling.[147] These include additional hydroelectric generation units at existing plants (Bay d'Espoir and Cat Arm), new hydro facilities (Island Pond, Round Pond, and Portland Creek), three CT options, wind (in generic 100 MW increments), four-hour, 50 MW battery energy storage systems ("BESS"), and solar photovoltaics (in generic 20 MW increments).[148] Additionally, NLH states that other resources "are currently being considered or are being closely monitored by [NLH] as potential future alternatives."[149] These resources include

---

[142] NLH, "Avalon Supply (Transmission) Study," October 31, 2023 ("Avalon Transmission Study"), page 2 lines 2 to 5.

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

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

[145] RAP Filing, Exhibit B, page 56 lines 16 to 17.

[146] RAP Filing, Exhibit C, section 7.3.

[147] RAP Filing, Exhibit C, page 25 lines 1 to 3.

[148] RAP Filing, Exhibit C, page 25 line 2 to page 26 line 4.

[149] RAP Filing, Exhibit C, page 25 lines 1 to 2.

"electrification, conservation, and demand management" ("ECDM") resources, capacity assistance resources, incremental capacity/efficiency potential from existing hydro units, simple-cycle combustion turbines ("SCCTs"), longer-duration BESS, market purchases, pumped storage (both upgrades to existing resources and new greenfield resources), and renewal of existing power purchase agreements ("PPAs").[150] NLH provides American Association of Cost Engineering ("AACE") Class 5 estimates for the supply options considered in the expansion plan modeling.[151] The table below provides those cost estimates and other key assumptions about the modeled supply resources. We then address key aspects of NLH's assumptions and supply resource options.

Table 3: Summary of Resource Options and Cost Estimates[152]

Resource Type	Resource	Rated Capacity (MW)	Cost of (Rated) Capacity ($/kW)	Firm Capacity (MW)	Cost of (Firm) Capacity ($/kW)	Average Energy (GWh)	Levelized Cost of Energy ($/MWh)	Fixed O&M ($/kW/yr.)	Variable O&M ($/MWh)
Hydro	BDE Unit 8	154	3,345	154	3,345	0	N/A	16	8
	CAT Unit 3	68	4,662	68	4,662	0	N/A	24	8
	Island Pond	36	15,570	36	15,570	186	213	121	8
	Round Pond	18	19,055	18	19,055	139	176	144	8
	Portland Creek	23	15,746	23	15,746	142	182	119	8
Thermal	3 CTs	142	3,204	142	3,204	35	N/A	20	6
Wind	100 MW	100	2,082	22	9,464	350	65	48	-
Battery	20 MW	20	2,740	12	4,566	0	N/A	110	-
	50 MW	50	2,221	30	3,701	0	N/A	89	-
Solar	20 MW	20	1,659	0	N/A	35	87	26	-
Proxy Capacity	50 MW	50	10,000	50	10,000	0	N/A	20	6

ECDM resources: NLH explains that it accounted for existing provincial ECDM activities in its load forecast.[153] This includes the takeCHARGE program, which provided modest capacity (13 MW) and energy (32 GWh) savings in 2023,[154] as well as forecast impacts of utility demand response programming for electric vehicles ("EVs") and customer conversions to heat pumps for space heating.[155] Because this issue is addressed in NLH's load forecast, we refer the reader to our July 25, 2024 assessment of NLH's load forecast, which is appended to this report as

150 RAP Filing, Exhibit C, page 25 line 2 to page 26 line 4.

151 RAP Filing, Exhibit C, page 24 lines 15 to 17, Table 1.

152 RAP Filing, Appendix C, Table 1.

153 RAP Filing, Appendix C, page 28 lines 21 to 23.

154 RAP Filing, Appendix C, page 28 lines 12 to 13.

155 RAP Filing, Appendix C, page 28 lines 21 to 23.

Attachment 1 – Bates White's July 25, 2024 Assessment of NLH's Load Forecast.

In addition to the forecasts of existing ECDM programs and initiatives, NLH states that it is "actively monitoring electrification trends," and data gathered "supports [NLH's] load forecasting."[156] NLH is also "seeking opportunities for beneficial electrification" and "supporting Newfoundland Power's Electric Vehicle Load Management Pilot Project," the results of which "will help inform ECDM strategies for future programming as it relates to EVs."[157] NLH is also waiting for receipt of a third-party study of potential for ECDM in the province, which is expected to conclude in 2024.[158] NLH explains that the results of that study will inform the next "multi-year ECDM plan" to be developed by NLH and other provincial utilities.[159] NLH also discusses electricity rate structures like time-of-use ("TOU") pricing and critical peak pricing ("CPP"), which create incentives for end users to shift their consumption patterns to lower overall system costs. NLH indicates that TOU and CPP programs have historically not been cost effective, though it acknowledges the potential for the economics of these programs to change.[160]

In our view, cost-effective ECDM programs can provide system benefits, including capacity, energy, and overall cost savings, and NLH's continued review of ECDM options and structures is worthwhile. NLH should clarify for parties exactly how it will incorporate its learnings from monitoring and studying ECDM options into its expansion planning efforts. It would seem that ECDM investments – if found viable and cost effective – could be in place to impact the RAP planning horizon. NLH should elaborate on its plans regarding potential future ECDM investments.

Unsubsidized cost estimates: As shown in Table 3 above, NLH provided cost estimates for thermal, hydro, wind, solar, and BESS projects, including capital costs ($/kW), fixed O&M ($/kW-year), and variable O&M ($/MWh).[161] We did not perform an assessment of NLH's sources and methods in developing its cost estimates, but we reviewed the estimates themselves (and their basic assumptions, as presented). We reviewed Daymark's analysis of NLH's cost estimates, in which Daymark benchmarks the NLH estimates against publicly available, credible third-party sources of cost estimates for similar projects. We also reviewed other sources of cost

---

[156] RAP Filing, Appendix C, page 29 lines 4 to 8.
[157] RAP Filing, Appendix C, page 29 lines 9 to 17.
[158] RAP Filing, Appendix C, page 30 lines 1 to 6.
[159] RAP Filing, Appendix C, page 30 lines 5 to 6.
[160] RAP Filing, Appendix C, page 30 lines 7 to 23.
[161] RAP Filing, Appendix C, Table 1.

data for further comparison, including Lazard's most recent levelized cost of energy report, released in June 2024.[162]

The result of our review is largely in agreement with that of Daymark. We did not identify any red flags associated with the assumed capital or O&M costs for wind or solar resources. For the 50 MW BESS project, NLH's capital cost assumption ($2,221/kW) is lower than Daymark's selected industry benchmarks ($2,366/kW and $2,851/kW, respectively).[163] However, NLH's estimate is above that of the high end of Lazard's estimate range for a four-hour duration, 100 MW BESS system ($2,120/kW).[164] NLH's estimate is for a smaller (and thus, likely higher per-kW capital cost) BESS system than the Lazard estimate. We therefore take no issue at this point with NLH's cost assumptions for BESS, though again we recognize that this may be an issue of discussion and discovery in the coming weeks.

Like Daymark, we noted two potential issues with NLH's assumed capital costs. The first regards the CT capital costs, which NLH assumes to be $3,204/kW for a 142 MW General Electric LM6000 unit.[165] This assumption appears high to us, consistent with Daymark's view.[166] Daymark's benchmark estimates, especially the Alberta Electric System Operator ("AESO") estimate of $1,662/kW, appears more reasonable to us and is in line with Lazard's high-end range estimate of $1,553/kW for a 50 MW gas peaker.[167] Cost estimates can vary with assumptions regarding the underlying unit change, and Daymark identifies "several inconsistencies" regarding NLH's cost estimate relative to the AESO benchmark.[168] When these inconsistencies are addressed, NLH's cost estimate is reduced to $2,382/kW, which appears more reasonable to us (and Daymark).[169] It does not appear NLH adjusted its cost estimate in response to Daymark's review, nor did NLH conduct any sensitivities in which the cost of a new CT was reduced. This is an issue that requires further explanation from NLH to ensure that the modeled capital cost of the CT supply option is reasonable.

The second issue relates to NLH's assumed capital cost for certain hydro supply resources, particularly BDE 8 and Cat Arm Unit 3, which NLH estimates at $3,345/kW and $4,662/kW, respectively.[170] Daymark's benchmark prices range from $4,805/kW to $31,862/kW, though Daymark notes that the costs for BDE 8 "may be reasonably expected to be near the lower end of

---

162 Lazard, "Levelized Cost of Energy," June 2024 ("Lazard LCOE Report"), available at: https://www.lazard.com/research-insights/levelized-cost-of-energyplus/.

163 RAP Filing, Appendix C, Attachment 1, page 8.

164 Lazard LCOE Report, page 44. We assume a USD/CAD exchange rate of 1.35.

165 RAP Filing, Appendix C, Table 1.

166 RAP Filing, Appendix C, Attachment 1, page 2.

167 Lazard LCOE Report, page 38. We assume a USD/CAD exchange rate of 1.35.

168 RAP Filing, Appendix C, Attachment 1, page 5.

169 RAP Filing, Appendix C, Attachment 1, page 5.

170 RAP Filing, Appendix C, Attachment 1, page 3.

industry benchmarks given the existing infrastructure and staffing," and therefore finds all hydro expansion supply option cost estimates to be reasonable.[171] Nevertheless, Daymark recommended a sensitivity modeling exercise in which hydro capital costs are "substantially higher" than the current estimate.[172] We agree with Daymark's suggested approach and we note NLH conducted such a sensitivity (sensitivity AD) in its RAP expansion modeling. We address the sensitivity specifications and results of those runs later in our report.

Subsidies: NLH does not explicitly identify a list of subsidies (i.e., tax credits) included in its expansion plan modeling. NLH does identify potential tax credits, including a potential 15% refundable tax credit rate for eligible investments in new equipment or refurbishment, among others.[173] NLH also indicates it is participating in the federal government process related to these tax credits and are monitoring the rules and regulations being developed, noting that the tax credits "could provide significant positive benefits to the cost of construction of [BDE 8]."[174] NLH should provide more information about these potential credits and could consider additional sensitivities to determine if forecasted tax credits have a material impact on selected supply options in the recommended expansion plan.

CT options considered: NLH identifies CTs as the sole thermal resource under consideration in this proceeding.[175] NLH largely bases this assumption on the 2023 study completed by Hatch, Ltd., the "CT Feasibility Study," which examined sizing and location of potential fuel-fired backup generation on the Avalon.[176] While the study is extensive, we observed only a consideration of aeroderivative gas turbines and industrial gas turbines,[177] but not a review of other options, such as reciprocating internal combustion engines ("RICE"). Heat rates are comparable and RICE units have the same fuel flexibility as CTs, including the ability to burn hydrogen. NLH should further explain if and how it considered RICE units as a supply option.

NLH also commissioned a study to review the grey market for existing CTs that could be commissioned earlier than a new resource and thus allow an earlier retirement date for one or more existing NLH thermal assets. The "Accelerated Holyrood Combustion Turbine Installation Options Study," while providing a number of useful insights, was narrowly focused on CTs currently in inventory. This approach may have eliminated hydrogen-compatible turbines,[178] currently being delivered and back-ordered by several manufacturers. There should be sufficient

171 RAP Filing, Appendix C, Attachment 1, page 6.
172 RAP Filing, Appendix C, Attachment 1, page 6.
173 RAP Filing, Appendix C, page 24 lines 18 to 24.
174 RAP Filing, Overview, page 56 lines 10 to 15.
175 RAP Filing, Appendix C, section 4.4.
176 RAP Filing, Appendix C, page 37 lines 5 to 8.
177 Hatch, Ltd., "Combustion Turbine Feasibility Study," October 10, 2023 ("CT Feasibility Study").
178 RAP Filing, Appendix C, Attachment 3, page 7. ("Primary fuel supply shall be No. 2 Diesel Fuel.")

time to procure such a CT for a commercial operations date of 2031 (or later). With CODs of 2031 and 2034, there should be sufficient time to select equipment and place an order with one of these manufacturers. The study points out the challenge of acquiring a turbine in the very short term and having to store it on the Island without the appropriate storage facilities.[179] This is a legitimate risk and could increase the cost of such an option. However, the turbine could be purchased now, stored at the current site, and delivered later. The study also notes the limited response to the vendor survey conducted in the above-referenced study.[180] In light of this, NLH should consider directly engaging the unresponsive vendors of hydrogen-compatible CTs to ascertain the availability of these units.

CT fuel choice (diesel): Another key consideration in assessing supply options to provide thermal generation on the Avalon is fuel choice. NLH commissioned a "Fuel Market Study" to assess the landscape for fuel options.[181] NLH selected diesel as the primary fuel source for the CT supply option, with the unit being able to burn renewable fuel as well.[182] Both the 2023 CT Feasibility Study and the Fuel Market Study conclude in favor of diesel, noting that the "supply landscape in Newfoundland and Labrador is dominated by diesel with limited supply of alternative fuels"[183] and that "no fuel is as perfect as fossil-derived diesel appears" for "Newfoundland's unique setting."[184] Nevertheless, both studies identify 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.[185]

NLH's Recommended Portfolio includes a 150 MW diesel-fired generator to be commissioned in 2031.[186] Building a new diesel-fired generator seems to carry significant risk of being subject to new and more stringent environmental regulations, particularly given a trend toward decarbonization. The Fuel Market Study also points out that the Canadian refining sector is facing structural and regulatory pressures that may reduce the availability of domestic No. 2 Diesel fuel, highlighting the need for importing the fuel.[187]

In addition to these risks, the Fuel Market Study may not have fully addressed some alternative fuel options. First, the Study dismisses the timely availability of locally-produced green hydrogen, in spite of at least two wind-to-green hydrogen projects in Newfoundland

179 RAP Filing, Appendix C, Attachment 3, page 14.
180 RAP Filing, Appendix C, Attachment 3, page 8
181 RAP Filing, Appendix C, section 4.4.1.
182 RAP Filing, Overview, page vi line 6.
183 CT Feasibility Study, section 1.6.2.
184 RAP Filing, Appendix C, Attachment 4, page 134.
185 See, for example, CT Feasibility Study, section 1.6.2; see also RAP Filing, Appendix C, Attachment 4, page 95.
186 RAP Filing, Appendix C, Table 54.
187 RAP Filing, Overview, page 38, lines 3 to 11.

(Project Nujio'qonik under development by World Energy GH2 in Stephenville[188] and the Toqlukuti'k Wind and Hydrogen Project under development by ABO Energy near the Braya Come by Chance refinery on the Avalon).[189] Second, the Study only briefly addresses the possibility of burning liquified natural gas ("LNG").[190] LNG storage and gasification facilities are a potential alternative to supply fuel to a gas-fired CT. A gasification facility with local storage right-sized for the 150 MW CT could allow for the importation of LNG, though the economics would require review.

Even setting aside alternative fuels, NLH should more thoroughly explain how it will address the logistical challenges of maintaining sufficient fuel supply at the new CT and comment upon any additional costs NLH may experience in maintaining reliability of that fuel supply. NLH should also provide more detail about the timing of a fuel conversion for the CT from diesel to a renewable source. Some of the same challenges that beset the supply chain for diesel fuel may challenge efforts to secure renewable fuel supply. We also suggest NLH address the possibility of holding a competitive solicitation for a turnkey CT solution, for which we provide some additional detail later in our report.

Hydro options considered: We offer a few observations regarding NLH's set of potential hydro supply options, which include three potential new resources and two new units at existing plants.[191] First, NLH indicates that it "intends to identify any opportunities to uprate units in [NLH's] fleet on the [IIS] to assess the feasibility of incremental capacity and/or efficiency," with a "detailed scope of work of this study in its entirety still under development."[192] NLH should explain the timing of this work and how, if at all, any identified uprates would impact NLH's Recommended Portfolio. Second, it is our understanding that the reservoir volume in the IIS' hydroelectric facilities cannot be easily increased. NLH should 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. Third, while it did not include the option in its Expansion Model, NLH is continuing to study the uprating of Bay d'Espoir Unit 7 ("BDE 7"), which may result in capacity increase of the unit by 20 to 26 MW.[193] NLH states that "the uprate analysis for [BDE 7] should be made in combination with the addition of [BDE 8], where both units should be considered concurrently for the determination of their respective optimal capacity and design."[194] We agree that the two options should be studied together, but wonder

---

188 World Energy GH2, "About Project Nujio'qonik," available at: https://worldenergygh2.com/about/.

189 ABO Energy, "Toqlukuti'k Wind and Hydrogen Project," available at: https://www.aboenergy.com/ca/company/projects/toqlukutik-project/.

190 RAP Filing, Appendix C, Attachment 4, Section 7.4.4.

191 RAP Filing, Appendix C, page 32 lines 7 to 15.

192 RAP Filing, Appendix C, page 36 lines 2 to 4.

193 RAP Filing, Appendix C, page 36 lines 23 to 26.

194 RAP Filing, Appendix C, page 36 line 26 to page 37 line 2.

how the potential uprate of BDE 7 is impacted by the fact that BDE 8 is already included in the Recommended Portfolio. NLH should address this issue.

BESS considerations: NLH considered and modeled BESS resources. NLH allowed for a range of ELCCs (40%, 60%, and 80%) and modeled a 50 MW, four-hour duration BESS. NLH rightly anticipates that BESS will likely "have a significant role in supporting future system operation," but notes that the limited duration of commercially-available BESS limits their effectiveness on NLH's system.[195] To the extent that planning the system is materially dependent on mitigating a prolonged LIL bipole outage, we agree that BESS resources would be of limited use during a prolonged LIL outage during the winter period, as there would be limited energy to allow for recharging of the batteries. As we discuss below, BESS resources are generally not selected in the model runs, with limited exceptions. We also note that NLH could consider 6- and 8-hour duration BESS projects, as such projects are commercially viable and available.

NLH reviewed but did not model BESS projects with durations as long as 100 hours.[196] NLH's review (conducted by a third party) provided limited commercial information and identified just one technology as potentially cost effective, but even that option is not yet commercially available.[197] We agree with NLH's decision to avoid first-of-a-kind technology risk and to wait for the long-duration storage market to mature before adding long-duration storage to its set of potential supply resource options.

Lastly, NLH assumes a five-year lead time due to lead times for power transformers and circuit breakers.[198] This assumption should be further supported, as it impacts the assumptions in several model runs (as explained in section G below).

Wind ELCCs: NLH assumes a 22% ELCC for new wind[199] and 0% ELCC for new solar.[200] Regarding wind, NLH's ELCC assumption is based on a 2019 ELCC study,[201] and it may be that meteorological and load conditions have remained sufficiently constant to make an ELCC update less necessary at this time. However, as NLH itself notes, ELCCs depend heavily on the location of the resources and the degree of penetration of that type of resource.[202] As penetration increases, ELCC decreases, and can do so steeply. As we discuss below, NLH's modeling results consistently rely on a buildout of 400 MW of wind, which at 22% ELCC would contribute 88 MW of firm capacity. It is possible that, depending on the timing and location of those wind

---

195 RAP Filing, Overview, page 40 lines 1 to 4.
196 RAP Filing, Appendix C, section 4.6.2.
197 RAP Filing, Appendix C, section 4.6.2.
198 RAP Filing, Appendix C, page 45 lines 17 to 22.
199 RAP Filing, Appendix B, page 32 lines 1 to 2.
200 RAP Filing, Appendix C, Table 1.
201 RAP Filing, Appendix B, page 31 lines 20 to 22.
202 RAP Filing, Appendix B, page 32 lines 2 to 3.

investments, actual ELCC of those projects could be lower. NLH recognizes this risk and states that it will assess the relationship between wind generation and the system as part of its ongoing resource efforts.[203] This is a helpful commitment, but it may be worth elaborating on this point, particularly when NLH shifts to procurement. NLH should consider a procurement methodology that recognizes the dynamic nature of ELCC calculations (which depends on wind penetration and location) to optimize the value of the wind resources it ultimately procures.

Options not considered (combined-cycle turbines, small modular nuclear reactors): NLH screened out as potential options combined-cycle combustion turbines ("CCCTs")[204] and small modular nuclear reactors ("SMRs").[205] Regarding SMRs, NLH identifies a direct legal prohibition of nuclear power in the province.[206] Regarding CCCTs, NLH states that "with the advancement of the draft *CER*, it has become clear that base-loaded, fossil-fuel fired facilities that provide a significant source of energy no longer have a long-term place in Canada's electricity network and therefore no longer have a place within the Island or Labrador Interconnected Systems."[207] This may be a valid reason for excluding CCCTs; however, it would be helpful for NLH to elaborate on what it means by "base-loaded," and whether NLH is identifying an implicit limitation on generation output from fossil-fired generators. If it is, we would ask NLH to reconcile this limitation with its consideration (and selection) of diesel-fired generation in the expansion planning process.

Third-party power considerations: NLH did not consider the potential extension of existing PPAs[208] (totaling 20 MW of firm capacity[209]) in its expansion plans. NLH states that it "will continue to work closely with PPA counterparties to determine options going forward."[210] This may be a reasonable assumption, but NLH should explain whether the existing PPAs contain any renewal rights and if so, the rates, terms, and conditions of such renewal rights. If available renewal terms are attractive, pursuit of a PPA renewal could drive savings and reduce the need for new resources. NLH could also commit to pursuing a competitive solicitation for energy and capacity that would allow for direct competition between supply options such as PPA extensions, third-party offers, and utility development options.

NLH also did not include market purchases as a supply resource option.[211] Here, long-term purchases mean long-term purchases of firm capacity from markets external to the province.

---

203 RAP Filing, page 32 lines 5 to 6.

204 RAP Filing, Appendix C, section 5.1.

205 RAP Filing, Appendix C, section 5.2.

206 RAP Filing, Appendix C, page 51 lines 6 to 7.

207 RAP Filing, Appendix C, page 50 line 23 to page 51 line 2.

208 RAP Filing, Appendix C, section 4.10.

209 RAP Filing, Appendix B, Table 9.

210 RAP Filing, Appendix C, page 50 lines 14 to 15.

211 RAP Filing, Appendix C, section 4.8.

NLH states that it "has not secured any capacity support from external markets for a duration longer than one month and does not have a basis to assume that such solutions would be available to meet long-term planning requirements."[212] While we do not have any evidence to suggest there are willing counterparties able to provide long-term firm capacity, and we recognize the challenging location of the province relative to the access of other markets, it may be useful for NLH to invite offers from parties in other provinces and markets to offer energy and capacity in a competitive solicitation. This would ensure NLH had exhausted possible sources of economic imports by allowing any offerors to compete with other potential sources of supply.

E. Scenarios and Sensitivities

Scenarios: NLH established eight scenarios for use in the expansion plan model. Variables that changed across the scenario were (1) the capacity planning criteria, (2) the LIL bipole equivalent forced outage rate, (3) the planning reserve margin, and (4) the IIS load forecast scenario.[213] 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. The scenarios NLH modeled are shown in the Table 4 below.

Table 4: Summary of Expansion Plan Scenarios[214]

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

NLH's "Reference Case," or case that NLH expects, is Scenario 1.[215] However, NLH's Recommended Portfolio is based on Scenario 4, which NLH characterizes as the "scenario requiring minimum investment (least amount of resource additions)."[216] The "Minimum

212 RAP Filing, Appendix C, page 47 lines 20 to 22.

213 RAP Filing, Appendix C, page 52 lines 2 to 5.

214 RAP Filing, Appendix C, Table 4.

215 RAP Filing, Appendix C, page 52 lines 14 to 15.

216 RAP Filing, Appendix C, page 53 lines 9 to 10.

Investment Required Case" (Scenario 4) makes two adjustments to the Reference Case (Scenario 1). First, it assumes a higher level of LIL reliability, assuming a bipole equivalent forced outage rate of 1% (as compared to 5% in the Reference Case). Second, it uses a lower load forecast (the "Slow Decarbonization" forecast) for the IIS, compared with the Reference Case's use of the "Reference" load forecast for the IIS.[217]

In our view, the Minimum Investment Required Case (Scenario 4) has 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.[218] And, notwithstanding our comments on NLH's load forecast (found in Attachment 1 – Bates White's July 25, 2024 Assessment of NLH's Load Forecastto this report), NLH appropriately applied the least aggressive, if not most likely, load forecast for the IIS. Thus, conceptually we agree with NLH that, among the scenarios presented, Scenario 4 would be best suited to identify the portfolio that requires the minimum investment.

The other scenarios are also important. Scenario 3, for example, isolates the marginal impact of a less reliable LIL as compared to the Minimum Investment Required Case. Specifically, Scenario 3 is identical to the Minimum Investment Required Case, except that a 5% LIL bipole equivalent forced outage rate is applied (rather than 1%). The result is a planning reserve margin of 25.8% (vs. 17.1% in the Minimum Investment Required Case), which translates into an additional 140 MW of needed capacity by 2032, as compared with the Minimum Investment Required Case.[219]

Scenario 7 shows the partial impact of a more stringent reliability planning criterion (0.1 LOLE). However, Scenario 7 does not isolate this impact relative to either the Minimum Investment Required Case, or the Reference Case. Scenario 7 uses the Slow Decarbonization IIS load forecast (which matches the Minimum Investment Required Case) but a 5% LIL bipole equivalent forced outage rate (which matches the Reference Case). This fails to provide an understanding of the isolated impact of the more stringent planning criteria application relative to those cases. However, Scenario 7 matches Scenario 3 in all variables other than the reliability planning criterion. A comparison of those two scenarios shows that the application of the 0.1 LOLE standard results in an incremental capacity need of 135 MW in 2032.[220]

Scenario 8 examines the impact of assuming the LIL to be an energy-only facility (i.e., providing no capacity benefits). When compared to the Reference Case, with which it is identical

217 RAP Filing, Appendix C, page 53 lines 9 to 14.

218 Haldar Report, page ii.

219 RAP Filing, Appendix B, Table 10.

220 RAP Filing, Appendix B, Table 11.

other than the LIL bipole equivalent forced outage rate, Scenario 8 results in an incremental capacity need of 175 MW in 2032.[221] This scenario, along with others, provides useful insights regarding the impact of certain variables (such as LIL reliability) on planning reserve margins and capacity needs. With additional variables that impact resource planning to address, NLH also performed sensitivity analyses, which we address next.

Sensitivities: NLH identified eleven sensitivities used to test the eight scenarios above. The sensitivities allow 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 CTs) or precluded from selection (BESS).[222] The scenarios are shown in the table below.

Table 5: Expansion Plan Summaries[223]

Sensitivity	Description
A	Fixed wind profile to meet firm energy criteria
AB40	Same as Sensitivity A with an assumed battery ELCC of 40%
AB80	Same as Sensitivity A with an assumed battery ELCC of 80%
AC	Same as Sensitivity A and removes forced CT fuel burn-off in consideration of the potential for contract negotiation and/or shelf life extension negating this requirement
AD	Same as Sensitivity A with the exception of increasing all Hydro capital costs by 50% in consideration of potential cost overruns
AE	Same as Sensitivity A and removes batteries as a resource option
AEC	A combination of Sensitivities A, AC, and AE to determine the impact of removing forced CT fuel burn-off in consideration of restricting batteries as a resource option
AEF	Same as Sensitivity AE with the additional restriction of limiting CT additions to 150 MW in consideration of current diesel fuel limitations on the Island
AEG	Same as Sensitivity AE with the exception of increasing CT fuel costs by 50% in consideration of potential future volatility in fuel costs
AEH	Same as Sensitivity AE with the exception of increasing CT capital costs by 50% in consideration of potential cost overruns
AEI	Same as Sensitivity AE with the addition of the potential Newfoundland Power 25 MW CTs in the years 2028, 2029, and 2030.^{91}

Sensitivity A forces the Expansion Model to include sufficient new wind resources to meet firm energy criteria, and is carried through in every other scenario,[224] other than the "unrestricted" scenario. We address NLH's firm energy analysis later in our report. However, we note here that it is the firm energy analysis that appears to identify wind for inclusion in the Recommended Portfolio, not the Expansion Model, and that selection has a direct impact on the

221 RAP Filing, Appendix B, page 44 lines 8 to 13.

222 RAP Filing, Appendix C, page 54 lines 4 to 6.

223 RAP Filing, Appendix C, Table 5.

224 RAP Filing, Appendix C, Table 5.

Expansion Modeling. Wind, with its assumed 22% ELCC, provides 22 MW of firm capacity for every 100 MW of additions, meaning the Recommended Portfolio (which includes 400 MW of wind) reflects 88 MW of firm capacity from wind. That firm capacity contribution is netted against the firm capacity need modeled in the Expansion Plan, reducing the resources selected by PLEXOS in the Expansion Plan. Given that the wind resources are manually included in the Expansion Model and contribute a non-trivial amount of firm capacity, this process should be a topic of further exploration and justification by NLH. This is particularly true given the potential concerns regarding wind ELCC assumptions, which we explain earlier in our report.

Another sensitivity that requires review and additional explanation is sensitivity AC, which removes the baseline assumption that a new CT will be required to burn off ten days of fuel storage each year.[225] NLH explains:

> At this time, [NLH] is assuming that ten days of fuel storage associated with the CT as a resource option has to be burned off annually. While further study is required to assess the shelf life of the fuel in storage, and/or determining if there is a way to cycle unused fuel via contractual means, the Expansion Model is being forced to burn off the fuel annually as a worst-case scenario to ensure [NLH] is fully capturing the associated costs. A sensitivity was designed to remove this fuel burn-off requirement; instead, fuel costs are reflective of forecast production requirements.[226]

We agree that NLH's decision to include a "no fuel burn-off requirement" is a useful sensitivity, as it appears NLH is unsure of the logistics of fuel storage with its planned CT supply resource (and its associated costs). Still, the baseline assumption of an annual fuel burn-off requires additional review, as it may be unreasonable. For example, we would expect NLH to simply consume the fuel at the CT for the production of electrical output, which would mitigate the cost of any forced fuel consumption requirement related to storage limitations, or to explore the use of biocide additives.

Other sensitivities attempt to capture the potential for cost overruns, including hydro[227] and CTs,[228] and higher-than-expected fuel costs.[229] Sensitivity AD, for example, increases all hydro supply option capital costs by 50% "in consideration of potential cost overruns."[230] In our view, a more severe cost overrun sensitivity is merited. As noted above, NLH's BDE 8 and Cat Arm 3 cost assumptions were considerably lower than Daymark's calculated benchmarks. While NLH has followed through on Daymark's recommendation to include a sensitivity that modeled higher

---

225 RAP Filing, Appendix C, section 6.2.1.1.6.

226 RAP Filing, Appendix C, page 63 lines 7 to 12.

227 See sensitivity AD, RAP Filing, Appendix C, Table 5.

228 See sensitivity AEH, RAP Filing, Appendix C, Table 5.

229 See sensitivity AEG, RAP Filing, Appendix C, Table 5.

230 RAP Filing, Appendix C, Table 5.

hydro capital costs, a greater cost overrun amount (75-150%) may be warranted to increase confidence in the Recommended Portfolio.

F. Modeling Approach and Considerations

Models used: NLH employed several models, including the Vista Model to produce its hydroelectric generation forecasts used in its Resource Planning Model,[231] the Reliability Model to determine planning reserve margins,[232] the Firm Energy model to assess firm energy needs,[233] the Resource Planning Model (i.e., the Expansion Model) to select resources,[234] the Transmission Model to determine any needed grid upgrades,[235] and the Long-Term Financial Model to determine the impact of investment on rates.[236] Our review of the functions of these models suggests that each plays a key and necessary role in the planning process and, as described by NLH, appears reasonable in their scope and approach. That said, we would expect that NLH will provide modeling data (inputs, outputs) to allow interested parties to review the models, their setups, and their results in detail.

To the extent referenced in the RAP filing, NLH is using reasonable models for its RAP process. NLH is using PLEXOS as its Resource Planning Model.[237] PLEXOS is a commercially available, off-the-shelf model offered by Energy Exemplar that is widely used in a variety of electric utility processes, including capacity expansion. NLH is also using a PLEXOS application as its Reliability Model.[238] Like PLEXOS, the Vista Model (used to generate hydroelectric forecasts) is a commercially-available model owned by Hatch, Ltd. For its Transmission Planning Model, NLH uses Siemens' Power System Simulator for Engineering ("PSSE") model.[239] Use of such industry-standard modeling applications increases confidence in the utility's modeling results, though review of the model setup, assumptions, and execution is still required to check that the results are reasonable.

Two other models were applied by NLH. The Firm Energy Model, which determines the firm energy requirements that meet NLH's planning criteria,[240] is an NLH-proprietary, spreadsheet-based model.[241] We address the specifics of this model below, but we note here that a firm

---

231 RAP Filing, Appendix B, page 14 lines 6 to 7.

232 RAP Filing, Appendix B, page 14 lines 8 to 10; see also RAP Filing, Appendix B, section 5.1.

233 RAP Filing, Appendix B, page 15 line 1.

234 RAP Filing, Appendix B, page 15 lines 2 to 5.

235 RAP Filing, Appendix B, page 15 line 6.

236 RAP Filing, Appendix B, page 15 lines 7 to 8.

237 RAP Filing, Appendix B, page 53 lines 14 to 15.

238 RAP Filing, Appendix C, page 12 line 12.

239 RAP Filing, Appendix B, page 56 lines 16 to 17.

240 RAP Filing, Appendix B, page 16 lines 5 to 6.

241 RAP Filing, Appendix B, page 46 lines 24 to 25.

energy analysis can be assessed in models such as PLEXOS. Daymark made a similar observation and recommended NLH incorporate the firm energy analysis process into the PLEXOS model.[242] We agree with Daymark's recommendation. The final model is the Financial Model, which determines the impact of the required investment on rates.[243] The model appears to be an NLH-proprietary, internal model.[244] For these models, we would expect NLH to provide modeling data and assumptions in the discovery process to allow interested parties to review and better understand the models and results.

Modeling issues: Earlier in this report, we address several issues, such as generator forced outage rates and ELCCs, that are key inputs into the expansion modeling conducted by NLH. We have also noted that we expect to review additional detail regarding the models used in the RAP process later in this proceeding. This will include items such as detailed output data from supply resources, transmission flows (including on the LIL), and granular reliability results (e.g., LOLH by month or season). That said, there are a few additional comments we wished to raise regarding the modeling as presented in the RAP.

First, we note that in addition to assuming a 22% ELCC for existing and new wind resources, NLH included in its modeling separate wind profiles for the winter and non-winter seasons.[245] Specifically, NLH applied a wind output profile for the December-March period and a separate profile for the April-November period.[246] NLH should provide these profiles, with associated support, to clarify the seasonal variability in wind that NLH sought to model.

Second, and similarly, NLH should provide the daily energy profiles simulated for use in the expansion and firm energy analysis models. NLH modeled Muskrat Falls at its full capacity year-round (i.e., no seasonal restrictions), with daily energy profiles that are simulated and vary by month.[247]

Third, NLH explains that it has modeled the LIL as a firm energy resource to the IIS system and thus a firm energy export from LIS, meaning that Muskrat Falls energy is not planned to be used to serve LIS customers in the future.[248] NLH states that there is a potential for Muskrat Falls energy to be "trapped" in Labrador if the LIL cannot accommodate flows.[249] While NLH may be able to store excess water upriver at Churchill Falls for use later at Muskrat Falls,[250] NLH

---

[242] RAP Filing, Appendix A, page 5.
[243] RAP Filing, Appendix B, page 16 lines 22 to 24.
[244] RAP Filing, Appendix C, page 103 lines 10 to 13.
[245] RAP Filing, Appendix B, section 5.1.2.3.
[246] RAP Filing, Appendix B, page 31 lines 17 to 19.
[247] RAP Filing, Appendix B, section 5.1.2.1.3.
[248] RAP Filing, Appendix B, page 52 line 24 to page 53 line 1.
[249] RAP Filing, Appendix B, page 53 lines 1 to 3.
[250] RAP Filing, Appendix B, footnote 81.

identifies a risk of spillage at Muskrat Falls, i.e., water not used to generate electricity, in certain low IIS load conditions or limitations on the LIL.[251] NLH explains that it is "will continue to evaluate the opportunity to optimize energy stored on the [LIS], including short-term energy sales, where appropriate."[252] To that end, NLH states that it has "agreed to sell 1.7 TWh of energy banked in the Churchill River reservoir on behalf of Muskrat Falls."[253] It appears reasonable to us to not count on any firm energy or capacity from Muskrat Falls in Labrador, but it would be helpful to better understand the status and details of the commercial arrangements with Hydro Quebec referenced by NLH.

Fourth, regarding modeling of the LIL, NLH noted its dependency on the Maritime Link and stated that due to this relationship, NLH developed an hourly capacity profile for the LIL that serves as a constraint on the LIL and that is based on the hourly IIS load profile and the firm contractual export commitments over the Maritime Link.[254] NLH should provide these hourly profiles to allow parties to better understand NLH's approach.

Fifth, if it has not already done so, NLH should provide detail regarding transmission losses assumptions and results, hydro spillage, and wind curtailments for its model runs. This will provide parties with a better understanding of the overall results and efficiency of each portfolio.

Sixth, NLH explains its energy and capacity export obligations and opportunities to both Nova Scotia (over the Maritime Link)[255] and Quebec.[256] Regarding Nova Scotia exports, NLH notes its obligations under the Energy and Capacity Agreement ("ECA") with Nova Scotia Power, which includes delivery of firm energy and capacity at both peak and off-peak hours.[257] NLH should clarify that it did not model any off-peak deliveries (i.e., "Supplemental Energy"), since that energy was only to be delivered in the first five years of the ECA. NLH should also explain how it modeled its obligations under the Energy Access Agreement with Nova Scotia Power, which is a 35-year contract obligation to offer Muskrat Falls energy to Nova Scotia Power in annual solicitations issued by Nova Scotia Power.

Regarding Quebec exports, NLH notes its ability to sell excess power to the New York, New England, and Ontario systems from Churchill Falls via the Hydro Quebec system.[258] NLH also notes that it entered into a PPA with Muskrat Falls for the purchase and sale of "Residual Block Energy," which calls for certain LIS load to be served by Muskrat Falls (rather than Churchill

---

[251] RAP Filing, Appendix B, page 53 lines 3 to 5.
[252] RAP Filing, Appendix B, page 53 lines 6 to 8.
[253] RAP Filing, Appendix B, footnote 82.
[254] RAP Filing, Appendix B, section 5.1.4.3.
[255] RAP Filing, Appendix B, section 5.1.3.3.
[256] RAP Filing, Appendix B, section 5.1.3.4.
[257] RAP Filing, Appendix B, section 5.1.3.3.
[258] RAP Filing, Appendix B, page 35 lines 5 to 6.

Falls), allowing Churchill Falls exports to external markets "helping to ensure maximum value from the organization's hydrological resources."[259] Given that NLH is proposing to invest in a capacity expansion portfolio in the coming years, NLH should provide additional detail about these export arrangements to ensure that NLH's internal needs are being met in the lowest cost manner and that any export activity is economic and driven by surplus power that cannot otherwise be reliably delivered where it is needed.

Seventh, regarding its Reliability Model, NLH selected a single representative year (2032) and applied the resulting planning reserve margins to the entire study period.[260] NLH explains that in selecting a representative year, it aimed to select a year "that most closely represents long-term system conditions."[261] NLH indicated that it could not select a year "prior to the retirement of the Holyrood TGS;" NLH explained that "the more the system resource characteristics deviate from the selected representative year, the less accurate the reserve margin will be," and thus "2032 was selected as the representative year since at that time, all currently proposed capacity resource additions and planned retirements are expected to have occurred."[262] It is typical for electric utilities to select a single year (or small subset of years) to be representative of the system, the results of which are then applied to the broader planning horizon. Selection of that representative year (or years) is critical, and while NLH has provided its rationale in the RAP filing, this is an item that should be further discussed and explored in this proceeding.

Eighth, NLH's Firm Energy Analysis appears to have been conducted over a significantly longer period than the Resource Planning Model. Specifically, Daymark indicates that NLH's Firm Energy Analysis addressed the period 2023 through 2042.[263] NLH should provide the full results of this analysis and explain any implications of the years beyond 2034 which are not otherwise discussed in the RAP filing.

G. Expansion Plan Results, Insights, and Next Steps

NLH provided results for 30 model runs in the RAP, including all twelve Reference Case sensitivities (Scenario 1),[264] all twelve Minimum Investment Required Case sensitivities (Scenario 4),[265] and results for the other six scenarios (Scenarios 2, 3, 5, 6, 7, and 8) under Sensitivity AEF (which includes the fixed wind profile, exclusion of BESS resources, and limits on CTs).[266] NLH also provided the results of the further tests completed on the selected

259 RAP Filing, Appendix B, page 35 lines 13 to 17.
260 RAP Filing, Appendix B, page 19 lines 7 to 24.
261 RAP Filing, Appendix B, page 19 lines 8 to 10.
262 RAP Filing, Appendix B, page 19 lines 18 to 24.
263 RAP Filing, Appendix A, page 4.
264 RAP Filing, Appendix C, section 6.2.1.
265 RAP Filing, Appendix C, section 6.2.2.
266 RAP Filing, Appendix C, section 6.3.

expansion portfolios, including an assessment of compliance with the *CER*, the LIL Shortfall Analysis, analysis of the On-Avalon transmission constraint, and the rate impact iteration analysis.[267] NLH put forth its Recommended Portfolio (based on Scenario 4AEF, albeit with the timing of the CT commissioning advanced from 2034 to 2031, as explained below).[268] NLH then included its action plan to address its identified energy, capacity, and transmission needs.[269] We assess some aspects of this portion of NLH's filing here.

1. Expansion Plan Results

Overall results of Resource Planning Model: As noted above, NLH provided results for 30 model runs. As shown in the table below, the most frequent resource selections were the CT (at least one CT selected in 25 out of 30 runs) and BDE 8 (selected in 24 out of 30 runs). The other options included Cat Arm Unit 3 (8 selections), BESS (5 selections), and the "proxy" capacity resource, a generic 50 MW CT used as a placeholder with a high capital cost[270] (five selections).

Table 6: Instances of Non-Zero Resource Selections (all model runs)[271]

	Runs Selected	% of Runs Selected
BDE 8	24	80%
CT	25	83%
CAT 3	8	27%
BESS	5	17%
Proxy	5	17%

The timing of the addition of selected resources varied in some cases. The model selected at least one CT to be built in 2031 in 19 model runs; in six other runs, the first CT additions came in either 2033 or 2034. For BDE 8, all 24 runs in which that resource was selected called for its addition in 2031.

Looking closer at Scenario 4 – the so-called "Minimum Investment Required Case" on which the Recommended Portfolio is based – both the CT and BDE 8 were selected in nine out of twelve cases (75%). Of the other options, only BESS is added (in two cases). This is shown in the table below.

---

[267] RAP Filing, Appendix C, section 7.0.
[268] RAP Filing, Appendix C, section 8.1.
[269] RAP Filing, Appendix C, section 9.0.
[270] RAP Filing, Appendix C, Table 1.
[271] RAP Filing, Appendix C, sections 6.2.1, 6.2.2, 6.3.

Table 7: Instances of Non-Zero Resource Selections (Scenario 4 runs only)[272]

	Runs Selected	% of Runs Selected
BDE 8	9	75%
CT	9	75%
BESS	2	17%
CAT 3	0	0%
Proxy	0	0%

We offer some observations from the results:

- In all cases, all existing thermal projects are retained until 2030, and no firm capacity additions are made prior to 2030. We raise this issue earlier in this report.
- In all 30 cases, wind is included—this is a manual insert by NLH as a result of the firm energy analysis, as explained earlier in this report. The timing and volume of wind additions varies, however. In 28 out of 30 cases, wind is added in 2030, but in all 28 cases, wind is "forced" into the model. Only in the two "unrestricted" model runs – Scenario 1 (Unrestricted)[273] and Scenario 4 (Unrestricted)[274] – where the model is able to choose the least cost portfolio with no modeled constraints – is wind added later (2032 and 2031, respectively). Notably, in these two unrestricted cases, the NPV of the portfolio is lowest.[275] NLH should clarify why this result occurred, i.e., why the addition of wind in the lowest cost portfolios is later than in all other portfolios. It is not clear to us if the Firm Energy Analysis was conducted for these runs, or if the Resource Planning Model selected these wind resources. It would be important to confirm if the wind resources were actually needed in 2030, or if a later commercial operations date would suffice.
- In all 30 model runs, at least 141.6 MW of capacity is added in 2031. In 13 cases, both BDE 8 and at least one CT is added in 2031. In eleven cases, only BDE 8 is added in 2031, while in the remaining six cases, only CT capacity is added in 2031.[276]
- The frequent selection of both BDE 8 and at least one CT is present in the results, as noted above. However, the relative ranking of these two options varies with the underlying assumptions.

---

272 RAP Filing, Appendix C, section 6.2.2.

273 RAP Filing, Appendix C, section 6.2.1.1.1.

274 RAP Filing, Appendix C, section 6.2.2.1.1.

275 RAP Filing, Appendix C, Chart 10; Chart 12.

276 RAP Filing, Scenario Summary Tables.

- For example, while BDE 8 is selected in 24 model runs, it goes unselected in all runs where either (a) hydro capital costs are 50% higher than expected[277] and (b) the CT is not required to burn off ten days of fuel per year.[278]
- The CT option, meanwhile, is selected in 25 model runs. However, the CT option is not selected in scenarios in which the BESS ELCC is assumed to be 80%, with the BESS option being selected instead.[279] The CT option is also not selected in three sensitivities in Scenario 4, including 4AEI (which assumes Newfoundland Power will build CTs).[280]

- One shortcoming that becomes evident in NLH's scenario analysis is that the two sensitivities in which CT costs are assumed higher – Sensitivity AEG, which assumes fuel costs are 150% of the baseline assumption, and Sensitivity AEH, which assumes CT capital costs are 150% of the baseline assumption[281] – also specify that BESS projects are excluded. Given the results of Scenario AB80 – which shows BESS being selected over CTs when BESS ELCCs equal 80% – it is a missed opportunity to clarify whether BESS projects would be selected over CTs when CT costs are assumed to be higher than the baseline.
- Of the 30 model run results provided, only 12 allowed BESS projects to be selected by the model.[282] Thus, BESS projects were selected in five out of twelve eligible cases (42%). Those included both modeled cases with BESS ELCCs equal to 80% (Scenarios 1AB80, 4AB80),[283] two baseline scenarios where BESS ELCC equaled 60% (Scenarios 1A, 4A),[284] and, perhaps most notably, in Scenario 1AD, where hydro capital costs were assumed to be 50% higher than baseline. In this last scenario, BDE 8 is not selected, while CT additions (2031, 2033) and BESS additions (2031) provide firm capacity to meet system needs.[285] Given these results, NLH should not dismiss BESS options on the basis of the Resource Planning Model results. We also note that BESS ELCCs may be closer to 80% than 60%; recent examples from PJM Interconnection and Idaho Power are illustrative.[286]

---

277 RAP Filing, Appendix C, section 6.2.1.1.7; section 6.2.2.1.6.

278 RAP Filing, Appendix C, section 6.2.1.1.6; section 6.2.1.1.9; section 6.2.2.1.5; section 6.2.2.1.8.

279 RAP Filing, Appendix C, section 6.2.1.1.4; section 6.2.2.1.4.

280 RAP Filing, Appendix C, section 6.2.2.1.2; section 6.2.2.1.4; section 6.2.2.1.4.

281 RAP Filing, Appendix C, Table 5

282 Only sensitivities A, AB40, AB80, AC, and AD allowed for BESS selection. See Table 5 above, or RAP Filing, Appendix C, Table 5.

283 RAP Filing Appendix C, section 6.2.1.1.4; section 6.2.2.1.4.

284 RAP Filing Appendix C, section 6.2.1.1.2; section 6.2.2.1.2.

285 RAP Filing Appendix C, section 6.2.1.1.7.

286 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.

- The Cat Arm 3 Unit and proxy capacity resource options are rarely selected and are available to the model in all 30 model runs.
- The cost of the resource portfolios also vary substantially depending on the underlying assumptions. It is not surprising that the portfolios selected in Scenario 1, which assumes higher load (the IIS Reference load forecast), have higher average costs (about $4.8 billion NPV)[287] than the Scenario 4 portfolios (about $2.8 billion),[288] which use reduced demand assumptions (Slow Decarbonization IIS load forecast).

Results of additional tests on resource portfolios: As noted above, NLH also provided the results of the further tests performed on the selected expansion portfolios, including an assessment of compliance with the *CER*, the LIL Shortfall Analysis, analysis of the On-Avalon transmission constraint, and the rate impact iteration analysis. We provide some observations on the results as presented.

- **CER results:** The CER (currently a draft) is proposed to take effect in 2035 and will likely only impact the CT resources.[289] NLH states: "With the information that is known today, [NLH] is confident that it will be able to comply with the draft CER, even with the addition of one or more 150 MW peaking CTs."[290] NLH indicates that a 150 MW CT is likely to face an emissions limit of 39.4 kt of carbon dioxide equivalent per year, which equates to about 60 GWh (16 days or 390 hours of operation).[291]
  - Our review of the estimated maximum emissions for each of the 30 model run portfolios suggests NLH's confidence is consistent with the results, which show total emissions over the 2031-2034 period that range between 25 kt and 74 kt of carbon dioxide equivalent.[292]
  - However, as with much of the RAP filing, these results could be affected by a prolonged bipole outage on the LIL. Hydro does anticipate there still would be compliance with the current draft *CER*.[293]
- **LIL Shortfall Analysis results:** NLH tested four "combinations": (1) no expansion resources and the Slow Decarbonization IIS load forecast; (2) the Recommended Portfolio (with the CT addition occurring in 2034) and the Slow Decarbonization IIS load forecast; (3) the Recommended Portfolio (with the CT addition occurring in 2031) and

287 RAP Filing, Appendix C, Chart 10.
288 RAP Filing, Appendix C, Chart 12.
289 RAP Filing, Overview, section 2.2.2
290 RAP Filing, Appendix C, page 106 lines 1 to 2.
291 RAP Filing, Appendix C, page 105 lines 2 to 6.
292 RAP Filing, Scenario Summary Tables.
293 RAP Filing, Appendix C, page 105, lines 3 to 8.

the Slow Decarbonization IIS load forecast; and (4) the Recommended Portfolio and the Reference Case IIS load forecast.[294]

  - The results for combination 1 are troubling and demonstrate the magnitude of the shortfall during such an outage with no new investment.[295]
  - The results for combination 2 and 3 should be reviewed in tandem. They suggest a material benefit of advancing the CT addition from 2034 (combination 2) to 2031 (combination 3). In the average case, total hours of unserved energy falls from 105 hours and 6 GWh (combination 2) to 4 hours and 0.1 GWh (combination 3).[296] The capacity shortfall results are similar. In the average case, the anticipated supply shortfall in combination 2 is 216 MW, while in combination 3, it falls to 85 MW.[297] This benefit will have a cost, which NLH should specify, as NLH has selected the CT to be added in 2031 in its Recommended Portfolio.[298]
  - One other observation worth noting is the lack of BESS projects in any portfolios subjected to the LIL Shortfall Analysis. As we explained above, BESS projects performed reasonably well in the Resource Planning Model runs in which BESS options were made available for selection. One valid criticism of BESS resources with limited durations (such as the four-hour BESS modeled by NLH) is that they would struggle to provide needed capacity during an extended LIL outage. Still, a LIL Shortfall Analysis assessment of a portfolio that included BESS would allow for better understanding of how such a portfolio would perform in the case of a prolonged LIL outage.

- **On-Avalon transmission constraint analysis:** The analysis, which relied in part on studies by TransGrid (explained earlier in this report), show that "[u]pon the retirement of the Holyrood TGS and Hardwoods GT on the Avalon, appreciable transmission bottlenecks will occur during a LIL bipole outage, resulting in trapped Off-Avalon generation."[299] As such, "increased transmission capacity along the Bay d'Espoir to Soldiers Pond corridor is needed to reduce the amount of load shedding required on the Avalon during a LIL bipole outage," while "[a]dvancing as much On-Avalon generation as possible to improve system reliability would increase the amount of load that can be served."[300] NLH identified a transmission upgrade (a third line from Western Avalon to

---

[294] RAP Filing, Appendix C, page 107 lines 6 to 15.

[295] RAP Filing, Appendix C, section 7.2.1.

[296] RAP Filing, Appendix C, sections 7.2.2, 7.2.3.

[297] RAP Filing, Appendix C, sections 7.2.2, 7.2.3.

[298] NLH does not currently cite the total NPV of their "4AEF(ADV)" Recommended Portfolio, though does provide anticipated rate changes, shown in RAP Filing, Appendix C, Table 46; Table 49.

[299] RAP Filing, Appendix C, page 128 lines 18 to 19.

[300] RAP Filing, Appendix C, page 128 lines 20 to 24.

Soldiers Pond and dynamic line ratings for TL201, TL202, TL206, and TL203) as the lowest cost solution ($150 million) and recommends this upgrade for all resource portfolio scenarios analyzed.[301] NLH notes that this would not eliminate on-Avalon load shed requirements during a LIL bipole outage, but would reduce load shed below 100 MW.[302] NLH is still reviewing the technical feasibility of other solutions.[303]

- **Rate impact iteration analysis:** NLH took a subset of expansion plans (including transmission upgrade costs) and applied them in its Long-Term Financial Model to determine the impact of the required investment on rates. Then, NLH assessed the impact of the higher rates on load, before finally re-running its Resource Planning Model with the lower load.[304] Estimated rate impacts are substantial[305] and when those higher rates were assessed for their impact on load, reductions of up to 48 MW of firm capacity and 259 GWh of firm energy were forecasted for the Scenario 4 portfolios.[306]
    - Given the lower firm capacity and energy needs, NLH then assessed whether those reductions were sufficient to alter the resource portfolios selected in the Resource Planning Model. In regard to the Recommended Portfolio, the model showed that the CT resource was no longer needed through 2034.[307] The model did show that the 400 MW of wind was still needed to meet the lower firm energy needs.[308]
    - Ultimately, however, NLH is retaining the CT addition in the portfolio it is advancing. This is due to the results of the iterated LIL Shortfall Analysis, which showed that with no CT addition, NLH would experience 76 hours and 4 GWh of unserved energy and a 186 MW capacity shortfall in the average case.[309] If the CT is built in 2031, NLH would experience just one hour and 0.1 GWh of unserved energy and 50 MW of capacity shortfall in the average case.[310] Based on these results, NLH maintained inclusion of the CT addition (in 2031) in its Recommended Portfolio.

301 RAP Filing, Appendix C, page 128 lines 25 to 27.
302 RAP Filing, Appendix C, page 129 lines 1 to 2.
303 RAP Filing, Appendix C, section 7.3.3.
304 RAP Filing, section 7.4.
305 See, for example, RAP Filing, Appendix C, Table 49.
306 RAP Filing, Appendix C, Table 51.
307 RAP Filing, Appendix C, page 140 lines 10 to 12.
308 RAP Filing, Appendix C, page 140 lines 14 to 18.
309 RAP Filing, Appendix C, page 141 lines 9 to 12.
310 RAP Filing, Appendix C, page 143 lines 1 to 6.

2. Recommended Portfolio

NLH's Recommended Portfolio is shown in the table below, including the timing of the investments, the incremental firm capacity (in MW), and the incremental firm energy (in GWh).

Table 8: NLH's Recommended Portfolio[311]

	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034
BDE Unit 8	154.4	0		1	1	1	1
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

Notwithstanding our discussion throughout this report, we make three observations about the Recommended Portfolio. First, we note it does not meet all reliability requirements of the Reference Case, largely due to a lower assumed LIL forced outage rate.[312] NLH proposes that in addition to the minimum investment (as a "first step"), it will monitor load growth and other factors to determine if more investment is needed.[313] This is an issue worth vetting in the upcoming review process. Second, the Recommended Portfolio would not meet the capacity and firm energy needs in NLH's expected IIS load forecast (the Reference Case). Again, this is an issue worth exploring with the Board and stakeholders. Third, the Recommended Portfolio is impacted by the threat of a prolonged LIL forced outage. NLH has included a CT resource despite the results of the rate impact iteration analysis, explained above, and has advanced the CT resource to be added in 2031. This issue, too, should be discussed with the Board and stakeholders in the coming weeks.

3. NLH's Proposed Next Steps

We conclude with a discussion of NLH's proposed and potential next steps in this process.

Regulatory action sought: NLH is preparing an application seeking regulatory approval for the investments identified in the Recommended Portfolio with an expected filing date in late 2024 or early 2025.[314] The Board should be wary of approving, in advance, the cost recovery of any investments that are to be developed by NLH between now and 2030 or 2031 (or later). NLH should explain any near-term commitments and/or expenditures that NLH may need to incur with respect to the proposed CT and BDE 8, prior to regulatory review and approval. NLH

311 RAP Filing, Appendix C, Table 54.

312 RAP Filing, Appendix C, page 146, lines 7 to 15.

313 RAP Filing, Appendix C, page 146, lines 14 to 15.

314 RAP Filing, Overview, page ix lines 6 to 8.

should also explain how it would address costs incurred on the CT and/or BDE 8 if, between now and 2031, the expected need for these units does not materialize.

FEED Studies: NLH states that it "will continue the advancement" of the BDE 8 and CT projects by completing front-end engineering and design ("FEED") studies.[315] NLH should provide additional detail about the planned timing for the respective plant FEED studies. NLH should also clarify whether the FEED studies will resolve questions regarding the referenced fuel burn-off requirement for the CT prior to NLH's application.

Risk of cost overruns: NLH identifies as next steps more refined cost estimates.[316] NLH should explain how it will seek cost recovery, and how it will manage risks associated with capital cost estimates (and potential overruns). NLH should provide its view on whether customers should take that risk, or whether NLH's cost estimates should be binding (with pre-determined allowances)?

Impact of ongoing resource adequacy efforts on Recommended Portfolio: NLH identifies several "ongoing" resource adequacy efforts alongside its recommended portfolio (for which it is already taking steps to implement). These include potential changes to BESS and wind ELCCs, enhanced ECDM offerings, and potential increased output from existing hydro units, among others. [317] NLH should explain how it will manage the potential for material changes in the supply and demand landscape on its plans to pursue a portfolio of capacity and firm energy resources.

Wind EOI: To address firm energy needs, NLH proposes to pursue a wind expression of interest ("EOI") process.[318] This may be a useful step, but we would caution that responses to EOIs are non-binding and may not reflect the ultimate cost, risk, and benefits that suppliers are willing to offer in a more formal, binding request for proposals ("RFP") process.

Use of competitive solicitation/RFP, third-party development: Other than the wind EOI process, it appears that NLH will propose to be the developer/owner of both the BDE 8 and CT projects. Given that BDE 8 is an addition to an existing NLH asset, this approach makes sense for that unit, though it could benefit from a competitive solicitation for an engineering, procurement, and construction ("EPC") vendor. The CT facility could be developed and potentially owned by a third-party that could execute a PPA with NLH. A PPA could de-risk aspects of the project for NLH and may reduce the urgency to receive pre-approval of the costs. NLH should consider and address the possibility of using competitive procurement where third

[315] RAP Filing, Appendix C, page 155 lines 20 to 23.

[316] RAP Filing, Appendix C, section 9.3.3.

[317] RAP Filing, Appendix C, section 10.0.

[318] RAP Filing, Appendix C, section 9.1.

parties can offer to provide turnkey CT solutions. NLH could, of course, offer a self-build option in such a procurement event.

Attachment 1 – Bates White's July 25, 2024 Assessment of NLH's Load Forecast

Assessment of Newfoundland and Labrador Hydro's Long-Term Load Forecast Report – 2023

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

Prepared by
Vincent Musco
Collin Cain
Nick Puga

July 25, 2024

TABLE OF CONTENTS

List of Tables

List of Figures

Abbreviations Used in Report

Bates White – Bates White, LLC
BEV – Battery Electric Vehicle
Board – Board of Commissioners of Public Utilities
CAGR – Compound Annual Growth Rate
Dunsky -- Dunsky Energy and Climate Advisors
EV – Electric Vehicle
EVA – Electric Vehicle Adoption
GDP – Gross Domestic Power
GHG – Greenhouse Gas
Government – Government of Newfoundland and Labrador
GWh – Gigawatt-hour
HDV – Heavy Duty Vehicles
ICE – Internal Combustion Engine
IIS – Island Interconnected System
kWh – Kilowatt-hour
LDV – Light Duty Vehicles
LIS – Labrador Interconnected System
Load Forecast Report – Long-Term Load Forecast Report – 2023
MDV – Medium Duty Vehicles
MHD – Medium and Heavy Duty
MM – Million
MSHP – Mini-split Heat Pumps
MURB – Multi-unit Residential Buildings
MW – Megawatt
NAP – Network Additions Policy
NL – Newfoundland
NLH – Newfoundland and Labrador Hydro
NP – Newfoundland Power
PHEV – Plug-in Hybrid Electric Vehicle
RRA – Reliability and Resource Adequacy Report
TWh – Terawatt-hour
YoY – Year over Year

I. Introduction

Bates White, LLC ("Bates White") appreciates the opportunity to provide comments on Newfoundland and Labrador Hydro's ("NLH's") Long-Term Load Forecast Report – 2023 ("Load Forecast Report"),[1] which was filed with the Board of Commissioners of Public Utilities ("Board") on March 28, 2024. Bates White was retained by the Board to conduct a review of NLH's Load Forecast Report and to provide comments for filing with the Board. The comments presented here fulfill that obligation.

II. Summary of Load Forecast Report

A. Background

NLH's Load Forecast Report contains the results of NLH's annual load forecasting efforts, completed in the third quarter of 2023.[2] The time horizon for the forecast includes 2023 through 2034.[3] NLH developed separate forecasts for both the Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS"). As NLH explains, the load forecasts are used across NLH's business operations, including general rate applications, financial budgeting, transmission planning, rate analysis, financing planning, and reliability and resource adequacy matters.[4] NLH also notes that the load forecast "is a key input to the resource planning process, which recommends what resources should be made available to meet projected demand within the province, consistent with applied reliability standards."[5]

Typically, NLH provides details of its load forecasts in its Reliability and Resource Adequacy ("RRA") Study Review filings.[6] The current Load Forecast Report, however, was submitted by NLH as a separate filing in response to a directive by the Board to "file the assumptions for each load forecast scenario as soon as possible and by the end of the first quarter 2024 at the latest."[7]

---

1 NLH, "Long-Term Load Forecast Report – 2023," March 28, 2024, ("Load Forecast Report").

2 Load Forecast Report, page i lines 5 to 6.

3 Load Forecast Report, page i line 6.

4 Load Forecast Report, page 1, lines 3 to 6.

5 Load Forecast Report, page 2, lines 3 to 5.

6 Load Forecast Report, page 1, line 7.

7 Load Forecast Report, page 1, lines 8 to 10.

NLH engaged Daymark Energy Advisors ("Daymark") to assess the 2023 load forecast methodology as well as the accuracy of NLH's historical forecasts.[8] Daymark concluded that, "Hydro's current load forecasting methodology reflects standard industry approaches for assessing potential growth."[9] Daymark noted various sources of NLH load uncertainty, and found that historical forecast errors were "within industry norms."[10]

B. Methodology

To develop its load forecasts, NLH forecasts requirements for both the IIS and LIS. NLH aims "to characterize and understand the range of possible system demand and energy requirements arising from the inherent uncertainty in the load forecast model inputs to ensure that [NLH] is prepared to serve its customers' needs in the near and long term."[11] For the current forecast, NLH developed a "Reference Case," which represents NLH's expectation of demand and energy requirements "based on the baseline expectations for economic growth and existing government policies and programs."[12] NLH also developed alternative cases "to determine the sensitivity of system requirements to changes in key inputs."[13]

The IIS forecast is the summation of interconnected utility load, industrial customer loads, and distribution losses. Transmission losses and station service are not included in the load forecast but are modeled and added later.[14] The IIS forecast combines "forecasts prepared for [1] load served by Newfoundland Power; [2] industrial customers' load served by NLH; and [3] rural load served by NLH."[15] The IIS forecasts depend on inputs such as (1) the economic forecast from the Government of Newfoundland and Labrador ("Government"), (2) Newfoundland Power load requirements,[16] (3) electric vehicle ("EV") adoption and load (developed by a third party, Dunsky Energy and Climate Advisors ("Dunsky")), (4) Government policies and programs, (5) electricity rates, and (6) industrial load requirements.[17]

For the IIS, NLH developed load forecasts based on three scenarios:

---

8 Daymark Energy Advisors, "R&RA 2024: Independent Load Forecasting Process Review," March 22, 2024, Attachment 1 to the Load Forecast Report.

9 *Id.*, page 15.

10 *Id.*, page 17.

11 Load Forecast Report, page 1 line 22 to page 2 line 3.

12 Load Forecast Report, page 2 lines 7 to 9.

13 Load Forecast Report, page 2 lines 9 to 11.

14 Load Forecast Report, page 3 lines 7 to 9, 15 to 17.

15 Load Forecast Report, page 3 lines 10 to 14.

16 Newfoundland Power provides service to the majority of customers on the IIS. For example, in 2022, Newfoundland Power provided 78 percent of IIS energy requirements and 85 percent of peak demand requirements. Load Forecast Report, page 4 lines 3 to 8.

17 Load Forecast Report, page 3 line 18 to page 5 line 17.

- The “Slow Decarbonization Path Scenario,” or “Slow Decarbonization” case, which assumes more moderate decarbonization efforts, slower electrification of the transportation sector, lower population growth and housing starts, and higher electricity rates. The Slow Decarbonization case results in the lowest load forecast for the IIS.
- The “Reference” case scenario assumes steady decarbonization and transportation electrification, lower electricity rates, and steady increases in population growth and housing starts. The Reference case results in higher forecasted load than the Slow Decarbonization case, but lower forecasted load than the Accelerated Decarbonization Path case.
- The “Accelerated Decarbonization Path Scenario,” or “Accelerated Decarbonization” case, assumes accelerated decarbonization and transportation electrification, higher population growth and housing starts, increases in industrial demand, and electricity rates equal to those in the Reference case. The Accelerated Decarbonization case results in the highest load forecast for the IIS.[18]

Figure 1 shows historical annual coincident demand for the IIS, and the three forecast scenarios, as presented in the Load Forecast Report. Figure 2 shows the corresponding information for the LIS.

[18] Load Forecast Report, page iii lines 7 to 18.

Figure 1: Island Interconnected System Annual Customer Coincident Demand Requirements[19]

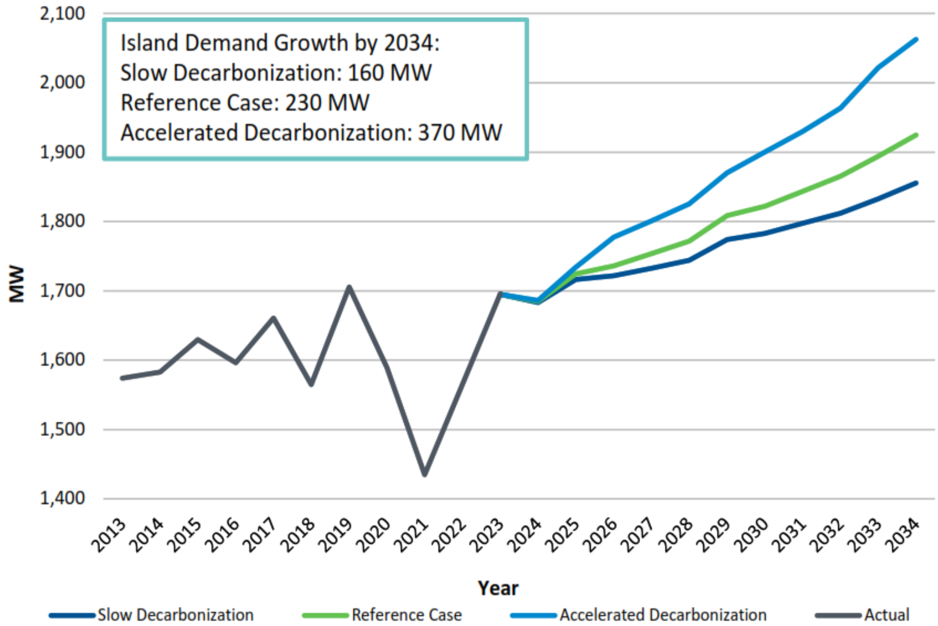
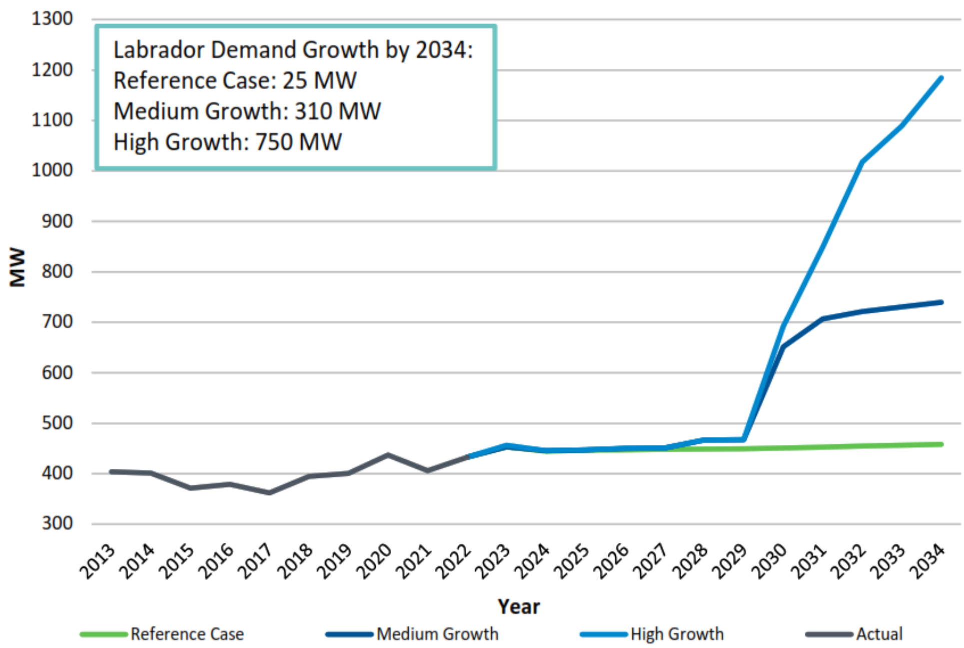


Figure 2: Labrador Interconnected System Annual Customer Coincident Demand Requirements[20]



[19] Load Forecast Report, reproduction of Chart 1, page v.

[20] Load Forecast Report, reproduction of Chart 2, page vi.

Table 1 below shows the annual energy values for the three load IIS forecast scenarios. The Slow Decarbonization case results in IIS energy demand growing from 7,790 GWh in 2023 to 8,703 GWh in 2034 at a compound annual growth rate ("CAGR") of 1.0 percent.[21] The Reference case sees higher load growth (9,172 GWh in 2034) at a higher CAGR of 1.5 percent, while the Accelerated Decarbonization case results in the highest load growth (9,890 GWh in 2034, CAGR of 2.1 percent.[22]

Table 1: IIS energy forecasts

IIS Energy (GWh)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	7,790	-	7,805	-	7,833	-
2024	8,075	3.66%	8,108	3.88%	8,169	4.29%
2025	8,172	1.20%	8,266	1.95%	8,368	2.44%
2026	8,164	-0.10%	8,305	0.47%	8,497	1.54%
2027	8,191	0.33%	8,355	0.60%	8,573	0.89%
2028	8,254	0.77%	8,440	1.02%	8,725	1.77%
2029	8,380	1.53%	8,597	1.86%	8,949	2.57%
2030	8,419	0.47%	8,692	1.11%	9,085	1.52%
2031	8,461	0.50%	8,780	1.01%	9,232	1.62%
2032	8,540	0.93%	8,907	1.45%	9,461	2.48%
2033	8,622	0.96%	9,039	1.48%	9,706	2.59%
2034	8,703	0.94%	9,172	1.47%	9,890	1.90%
CAGR	**1.01%**		**1.48%**		**2.14%**	

Table 2 shows the results of the three load forecast cases for the IIS peak load. The Slow Decarbonization case results in IIS peak demand growth from 1,696 MW in 2023 to 1,856 MW in 2034, at a CAGR of 0.8 percent.[23] Peak load growth in the Reference case is higher (1,925 MW in 2034, 1.2 percent CAGR), and the Accelerated Decarbonization case is the highest (2,063 MW in 2034, 1.8 percent CAGR).[24]

---

[21] Data compiled from Load Forecast Report, Table A-4.

[22] Data compiled from Load Forecast Report, Table A-4.

[23] Data compiled from Load Forecast Report, Table A-4.

[24] Data compiled from Load Forecast Report, Table A-4.

Table 2: IIS peak demand forecasts

IIS Peak Demand (MW)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	1,696	-	1,696	-	1,696	-
2024	1,683	-0.77%	1,685	-0.65%	1,686	-0.59%
2025	1,716	1.96%	1,725	2.37%	1,734	2.85%
2026	1,722	0.35%	1,736	0.64%	1,777	2.48%
2027	1,733	0.64%	1,753	0.98%	1,801	1.35%
2028	1,744	0.63%	1,772	1.08%	1,825	1.33%
2029	1,774	1.72%	1,809	2.09%	1,870	2.47%
2030	1,783	0.51%	1,822	0.72%	1,900	1.60%
2031	1,797	0.79%	1,843	1.15%	1,930	1.58%
2032	1,812	0.83%	1,865	1.19%	1,964	1.76%
2033	1,833	1.16%	1,894	1.55%	2,022	2.95%
2034	1,856	1.25%	1,925	1.64%	2,063	2.03%
CAGR	**0.82%**		**1.16%**		**1.80%**	

The LIS forecast is the summation of interconnected utility load, industrial customer loads, and distribution losses.[25] The LIS forecast combines forecasts prepared for [1] industrial customers served by NLH; [2] rural load served by NLH; and [3] EV requirements forecast.[26] The LIS forecasts is prepared using inputs such as (1) industrial customer forecast load requirements, including the potential for new industrial customers, (2) rural economic growth, which can drive industrial, commercial, and residential growth, and (3) EV adoption and load.[27]

NLH also developed three scenarios for the LIS forecast. The scenarios used were:

- The "Reference" case, which reflects current decarbonization and consistent industrial loads. The Reference case results in the lowest load forecast for the LIS.
- The "Medium Growth Scenario" case, or "Medium Growth" case, which forecasts higher industrial load growth. The Medium Growth case results in higher forecasted load than the Reference case, but lower forecasted load than the High Growth Scenario case.

25 As with the IIS forecast, transmission losses and station service are not included in the load forecast but modeled and added later.

26 Load Forecast Report, page 6 lines 7 to 11.

27 Load Forecast Report, page 6 line 12 to page 7 line 8.

- The "High Growth Scenario" case, or "High Growth" case, which assumes accelerated decarbonization and electrification and higher industrial load growth. The High Growth case results in the highest load forecast for the LIS.[28]

Table 3 and Table 4 below shows the results of the three load forecast cases for the LIS's energy and demand forecasts. The Reference case results in flat energy demand and modest peak demand growth, from 422 MW in 2023 to 458 MW in 2034, at a CAGR of 0.8 percent.[29] The Medium Growth case forecasts energy demand growth from 2,816 GWh in 2023 to 4,758 GWh in 2034, at a CAGR of 4.9 percent, plus peak demand growth from 422 MW in 2023 to 740 MW in 2034, at a CAGR of 5.2 percent.[30] The High Growth case results in the highest energy demand growth (reaching 8,132 GWh in 2034, CAGR of 10.1 percent) and peak demand growth (reaching 1,184 MW in 2034 at a CAGR of 9.8 percent).[31]

Table 3: LIS energy forecasts

LIS Energy (GWh)						
Year	**Reference Case**	**YoY Growth Rate**	**Medium Growth**	**YoY Growth Rate**	**High Growth**	**Growth Rate**
2023	2,741	-	2,816	-	2,816	-
2024	2,694	-1.71%	2,772	-1.56%	2,772	-1.56%
2025	2,697	0.11%	2,778	0.22%	2,778	0.22%
2026	2,701	0.15%	2,790	0.43%	2,791	0.47%
2027	2,705	0.15%	2,829	1.40%	2,831	1.43%
2028	2,706	0.04%	2,875	1.63%	2,880	1.73%
2029	2,711	0.18%	3,081	7.17%	3,086	7.15%
2030	2,717	0.22%	4,155	34.86%	4,510	46.14%
2031	2,721	0.15%	4,539	9.24%	5,665	25.61%
2032	2,729	0.29%	4,637	2.16%	6,909	21.96%
2033	2,736	0.26%	4,700	1.36%	7,434	7.60%
2034	2,744	0.29%	4,758	1.23%	8,132	9.39%
CAGR	**0.01%**		**4.88%**		**10.12%**	

28 Load Forecast Report, page iv lines 3 to 8.

29 Data compiled from Load Forecast Report, Appendix A.

30 Data compiled from Load Forecast Report, Appendix A.

31 Data compiled from Load Forecast Report, Appendix A.

Table 4: LIS peak demand forecasts

LIS Peak Demand (MW)						
Year	Reference Case	YoY Growth Rate	Medium Growth	YoY Growth Rate	High Growth	Growth Rate
2023	422	-	422	-	422	-
2024	445	5.45%	446	5.69%	446	5.69%
2025	447	0.45%	447	0.22%	448	0.45%
2026	447	0.00%	450	0.67%	450	0.45%
2027	448	0.22%	451	0.22%	451	0.22%
2028	449	0.22%	467	3.55%	467	3.55%
2029	450	0.22%	467	0.00%	468	0.21%
2030	451	0.22%	651	39.40%	692	47.86%
2031	453	0.44%	707	8.60%	849	22.69%
2032	455	0.44%	721	1.98%	1,018	19.91%
2033	456	0.22%	731	1.39%	1,089	6.97%
2034	458	0.44%	740	1.23%	1,184	8.72%
CAGR	**0.75%**		**5.24%**		**9.83%**	

C. Assumptions

Both the IIS and LIS forecasts are impacted by assumptions about key variables. We detail the most significant of these assumptions here.

1. IIS: Economic Forecast

The economic outlook for a utility's footprint is an important variable in any load forecast, as increases in economic activity can drive higher demand for power among all classes of electricity consumers. NLH relies exclusively on the Government's annual long-term economic forecast for the IIS system.[32] For the residential sector, the data includes forecasts of new housing starts (which are used to generate the expected number of residential customers) and household income (which is used to determine average customer use).[33] For the commercial sector (or "general service") at Newfoundland Power, NLH uses adjusted gross domestic product ("GDP") and non-residential building investment data from the Government as primary inputs to the forecast.[34] NLH's rural general service sales are generated using Government forecasts of household disposable income and value of fish landings.[35]

32 Load Forecast Report, page 11 lines 8 to 9.

33 Load Forecast Report, page 11 lines 15 to 18.

34 Load Forecast Report, page 11 lines 18 to 20.

35 Load Forecast Report, page 11 lines 20 to 21.

Both the Slow Decarbonization case and Reference case reflect identical GDP growth assumptions,[36] with a CAGR of 0.44 percent. The Accelerated Decarbonization case results in lower economic growth, with a CAGR of 0.30 percent.[37] This is shown in Table 5 and Table 6, below.

Table 5: GDP Forecast (2012$, MM)

IIS GDP (2012$, MM)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	23,101	-	23,101	-	23,118	-
2024	22,963	-0.60%	22,963	-0.60%	23,287	0.73%
2025	23,495	2.32%	23,495	2.32%	23,819	2.28%
2026	23,654	0.68%	23,654	0.68%	23,978	0.67%
2027	23,607	-0.20%	23,607	-0.20%	23,577	-1.67%
2028	23,946	1.44%	23,946	1.44%	24,107	2.25%
2029	24,036	0.38%	24,036	0.38%	24,112	0.02%
2030	23,401	-2.64%	23,401	-2.64%	23,317	-3.30%
2031	23,003	-1.70%	23,003	-1.70%	22,886	-1.85%
2032	23,551	2.38%	23,551	2.38%	23,408	2.28%
2033	24,024	2.01%	24,024	2.01%	23,873	1.99%
2034	24,250	0.94%	24,250	0.94%	23,881	0.03%
CAGR	**0.44%**		**0.44%**		**0.30%**	

[36] NLH excludes production-related income earned by the non-resident owners of mining, oil, and gas projects. Load Forecast Report, page A-1, n.1.

[37] Load Forecast Report, Tables A-1 through A-3.

Table 6: Household Disposable Income Forecast (2012$, MM)

IIS Household Disposable Income (2012$, MM)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	13,623	-	13,623	-	13,649	-
2024	13,648	0.18%	13,648	0.18%	13,818	1.24%
2025	13,775	0.93%	13,775	0.93%	14,017	1.44%
2026	13,872	0.70%	13,872	0.70%	14,195	1.27%
2027	13,996	0.89%	13,996	0.89%	14,307	0.79%
2028	14,230	1.67%	14,230	1.67%	14,632	2.27%
2029	14,428	1.39%	14,428	1.39%	14,832	1.37%
2030	14,619	1.32%	14,619	1.32%	15,036	1.38%
2031	14,626	0.05%	14,626	0.05%	15,062	0.17%
2032	14,846	1.50%	14,846	1.50%	15,292	1.53%
2033	14,977	0.88%	14,977	0.88%	15,444	0.99%
2034	15,015	0.25%	15,015	0.25%	15,530	0.56%
CAGR	**0.89%**		**0.89%**		**1.18%**	

Like the GDP forecasts, the forecast of household disposable income over the time horizon is equal in the Slow Decarbonization and Reference cases, with a CAGR of 0.89 percent. However, household disposable income is forecasted to be slightly *higher* in the Accelerated Decarbonization case (despite the lower forecasted GDP growth), with a CAGR of 1.18 percent.[38] The Accelerated Decarbonization case also forecasts higher commercial building investment (2034 value: $588 million) than the Slow Decarbonization and Reference cases (2034 value: $576 million).[39]

The forecast for housing starts and population are each highest in the Accelerated Decarbonization Scenario. The Accelerated Decarbonization case reflects 1.76 percent CAGR and a 2034 ending value of 1,690 housing starts, while the Reference case (1.15 percent CAGR, 2034 value of 1,602 housing starts) and Slow Decarbonization case (1.28 percent CAGR, 2034 value of 1,410 housing starts) are lower.[40] This is shown in Table 7 below.

---

38 Load Forecast Report, Tables A-1 through A-3.

39 Load Forecast Report, Tables A-1 through A-3.

40 Load Forecast Report, Tables A-1 through A-3.

Table 7: Average Housing Starts Per Year Forecast

Average Housing Starts per Year						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	1,226	-	1,412	-	1,395	
2024	1,361	11.01%	1,619	14.66%	1,660	19.00%
2025	1,449	6.47%	1,743	7.66%	1,818	9.52%
2026	1,453	0.28%	1,709	-1.95%	1,805	-0.72%
2027	1,402	-3.51%	1,606	-6.03%	1,680	-6.93%
2028	1,405	0.21%	1,614	0.50%	1,713	1.96%
2029	1,383	-1.57%	1,602	-0.74%	1,696	-0.99%
2030	1,360	-1.66%	1,581	-1.31%	1,667	-1.71%
2031	1,339	-1.54%	1,542	-2.47%	1,629	-2.28%
2032	1,376	2.76%	1,593	3.31%	1,673	2.70%
2033	1,402	1.89%	1,611	1.13%	1,689	0.96%
2034	1,410	0.57%	1,602	-0.56%	1,690	0.06%
CAGR	**1.28%**		**1.15%**		**1.76%**	

Population growth assumptions are similar. Population grows at 0.33 percent CAGR in the Accelerated Depreciation with a 2034 population of 553,800,[41] moderately higher than the Reference case (0.20 percent CAGR, 2034 population of 542,500) and Slow Decarbonization case (0.12 percent CAGR, 2034 population of 533,600).[42] This is shown in Table 8 below.

41 Load Forecast Report, Table 2.

42 Load Forecast Report, Tables 2, A-1, A-2, and A-3.

Table 8: Population Forecast (000s)

Population (000)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	527	-	531	-	534	
2024	528	0.19%	532	0.19%	536	0.37%
2025	529	0.19%	533	0.19%	538	0.37%
2026	529	0.00%	534	0.19%	539	0.19%
2027	530	0.19%	534	0.00%	541	0.37%
2028	530	0.00%	535	0.19%	542	0.18%
2029	531	0.19%	537	0.37%	544	0.37%
2030	532	0.19%	538	0.19%	547	0.55%
2031	532	0.00%	539	0.19%	548	0.18%
2032	533	0.19%	540	0.19%	550	0.36%
2033	533	0.00%	542	0.37%	552	0.36%
2034	534	0.19%	543	0.18%	554	0.36%
CAGR	**0.12%**		**0.20%**		**0.33%**	

2. IIS: Decarbonization and Electrification

For the IIS forecast, NLH considered the timing and impact of certain public policies, including mandates, regulations, incentives, and carbon pricing.[43] These included the Canada Greener Homes Grant (an energy efficiency incentive),[44] new oil-to-electric heating conversion incentives,[45] and a price on greenhouse gas ("GHG") emissions that begins at $65/tonne in 2023 and increases annually through 2030 at $15/tonne per year,[46] reaching $170/tonne in 2030 and remaining at that level through 2034.[47]

Across the three forecast scenarios, the only difference regarding decarbonization and electrification was in regard to installations of electric heating. In the Accelerated Decarbonization case, NLH assumed 100% of new constructions would be required to be electrically heated, and that existing households and business owners would be required to install an electric heating system when their current oil tank expires. In the Reference and Slow Decarbonization cases, no such assumption was included.[48] The Reference case assumes that 71

43 Load Forecast Report, page 14 lines 7 to 10.

44 Load Forecast Report, page 14, n. 32.

45 Load Forecast Report, page 14, n. 33.

46 Load Forecast Report, page 14, n. 34.

47 NLH Response to PUB-NLH-316.

48 NLH Response to PUB-NLH-316 (b-c).

percent of homes that are currently oil-heated but have an oil tank that will expire during the forecast period and will convert to electric heat, and in the commercial sector, all new customers are assumed to use electric heat, with a modest amount of commercial conversions to electric heat from oil.[49] In the Slow Decarbonization case, NLH assumes 59 percent of homes will convert to electric heat upon oil tank expiration, with the same assumptions regarding commercial customers as in the Reference case.[50] All other incentives and GHG pricing remained the same across all three cases.[51] Table 9 and Table 10 below show the details of the heating sector electrification assumptions and the assumed GHG prices, respectively, across the three scenarios.

Table 9: Heating Electrification Assumptions[52]

Heating Sector Electrification Assumptions			
Case	Residential Conversions	% of 40,000 Available Conversions	Government Building Conversions (2034, GWh)
Slow Decarbonization	12,400	31.00%	6.5
Reference	15,100	37.75%	6.5
Accelerated Decarbonization	24,400	61.00%	82.0

Table 10: GHG Price Assumptions, all scenarios ($/tonne)[53]

Year	GHG Price ($/tonne)
2024	$80.00
2025	$95.00
2026	$110.00
2027	$125.00
2028	$140.00
2029	$155.00
2030	$170.00
2031	$170.00
2032	$170.00
2033	$170.00
2034	$170.00

49 Load Forecast Report, page 14 lines 11 to 17.

50 Load Forecast Report, page 14 lines 18 to 20.

51 NLH Response to PUB-NLH-316 (a-c).

52 Load Forecast Report, Table 3.

53 NLH Response to PUB-NLH-316 (a); Load F.

3. IIS: Electric Vehicles

The forecast of EVs was provided by Dunsky and assumed three possible futures: a Slower EV Adoption Forecast (which was included in the Slow Decarbonization case), a Reference EV Adoption Forecast (used in the Reference case), and the Accelerated EV Adoption forecast (used in the Accelerated Decarbonization case).[54] Dunsky's forecast included both battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs").[55]

The Slow Decarbonization case assumes 56,819 light duty EVs and 2,662 Medium- and Heavy-Duty ("MHD") EVs (and buses) on the road by 2034, growing at a CAGR of 42.8 percent and 43.8 percent, respectively.[56] The Reference case forecasts 82,383 light duty EVs (CAGR of 46.86 percent) and 3,613 MHD EVs (CAGR of 44.71 percent) by 2034.[57] The Accelerated Decarbonization case assumes 97,435 light duty EVs (CAGR of 47.02 percent) and 4,289 MHD EVs (CAGR of 42.98 percent) in 2034.[58] Table 11 and Table 12 below show the annual increases in EV stock for both light duty and MHD (plus buses) EVs for the forecast time horizon.[59]

Table 11: Light-Duty Electric Vehicle Annual Sales Forecast

IIS EV Stock (Light-Duty Vehicles)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	1,133	-	1,202	-	1,405	
2024	1,833	61.78%	1,989	65.47%	2,553	81.71%
2025	3,010	64.21%	3,343	68.07%	4,516	76.89%
2026	4,857	61.36%	5,555	66.17%	7,568	67.58%
2027	7,364	51.62%	8,880	59.86%	11,893	57.15%
2028	10,755	46.05%	13,857	56.05%	18,062	51.87%
2029	15,202	41.35%	20,868	50.60%	26,468	46.54%
2030	20,948	37.80%	29,982	43.67%	37,179	40.47%
2031	27,654	32.01%	40,897	36.41%	49,829	34.02%
2032	36,106	30.56%	53,317	30.37%	64,102	28.64%
2033	45,742	26.69%	67,181	26.00%	79,988	24.78%
2034	56,819	24.22%	82,383	22.63%	97,435	21.81%
CAGR	**42.75%**		**46.86%**		**47.02%**	

[54] Load Forecast Report, page 8 lines 2 to 8.

[55] BEVs are EVs that have only an electric powertrain and that plug in to charge. PHEVs are vehicles that plug in to charge and operate in electric mode for short distances but also include a combustion powertrain for longer trips. Load Forecast Report, Attachment 2, page 7.

[56] Load Forecast Report, Table A-7.

[57] Load Forecast Report, Table A-7.

[58] Load Forecast Report, Table A-7.

[59] Note that our CAGR calculation assumes an existing stock of 400 light duty EVs and MHD EVs (plus buses) at the end of 2022. Load Forecast Report, Attachment 2, page 10.

Table 12: Medium-, Heavy-Duty Electric Vehicle (including Buses) Annual Sales Forecast

IIS Cumulative EV Sales (Medium and Heavy Duty Vehicles and Buses)						
Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	49		62		84	
2024	86	75.51%	108	74.19%	150	78.57%
2025	132	53.49%	167	54.63%	238	58.67%
2026	205	55.30%	261	56.29%	374	57.14%
2027	289	40.98%	377	44.44%	559	49.47%
2028	402	39.10%	551	46.15%	802	43.47%
2029	553	37.56%	794	44.10%	1,109	38.28%
2030	753	36.17%	1,120	41.06%	1,502	35.44%
2031	1,049	39.31%	1,543	37.77%	1,997	32.96%
2032	1,454	38.61%	2,084	35.06%	2,607	30.55%
2033	1,985	36.52%	2,766	32.73%	3,362	28.96%
2034	2,662	34.11%	3,613	30.62%	4,289	27.57%
CAGR	**43.79%**		**44.71%**		**42.98%**	

4. IIS: Conservation and Energy Efficiency

NLH assumed an equal amount of energy savings through utility conservation programs in all three load forecast scenarios.[60] The conservation estimate was provided by takeCHARGE.[61]

Additionally, NLH included assumptions about the adoption of mini-split heat pumps ("MSHPs"). NLH assumed that any homes that use non-electric heating that install MSHPs would be captured in the oil-to-electric heating conversion program, mentioned above.[62] For customers that use electric heating, NLH assumed that 61 percent of Newfoundland Power's residential customers will have installed MSHPs in their homes by the end of 2034 in both the Accelerated Decarbonization and Reference cases.[63] NLH assumed greater MSHP adoption (and thus lower electric load) in the Slow Decarbonization case (66 percent of electric heating customers).[64]

60 Load Forecast Report, page 16 lines 9 to 11.

61 Load Forecast Report, page 16 lines 9 to 11.

62 Load Forecast Report, page 17 lines 4 to 6.

63 Load Forecast Report, page 17 lines 7 to 9.

64 Load Forecast Report, page 17 lines 10 to 11.

5. IIS: Industrial Customer Growth

The Slow Decarbonization and Reference cases each assume that all six current IIS industrial customers will remain through 2034 and will continue at levels currently forecasted by the industrial customers.[65] In addition, these two cases include an assumed 10 MW of new firm demand in 2028 tied to "hydrogen developments."[66] The Accelerated Decarbonization case includes the same assumptions as the Reference and Slow Decarbonization cases, but the increase in load related to hydrogen developments is 40 MW, with 20 MW added in 2028 and 20 MW more in 2032, and one industrial customer converting to electric heating.[67] The Reference and Slow Decarbonization cases see 220 MW of IIS industrial peak demand in 2034 (an increase of 60 MW relative to 2023), while the Accelerated Decarbonization case forecasts 280 MW of peak demand in 2034 (an increase of 120 MW relative to 2023).[68]

6. IIS: Weather Data

NLH's load forecasts include assumptions regarding heating degree days[69] and wind chill. NLH estimates a normal weather year using a rolling 30-year average for the initial starting value of heating degree days.[70] NLH then applies a linear trend model over the forecast period to reflect gradual warming reflected in recent weather history.[71] In forecasting peak demand, NLH uses a 30-year rolling average wind chill value (P50).[72]

7. IIS: Electricity Rates

An important input to any utility load forecast is the retail rates to be paid by its customers over the time horizon. NLH assumed the same rates for the Reference and Accelerated Decarbonization cases (3.05 percent CAGR, 2034 average rate equal to 19.20 cents/kWh), and slightly higher rates for the Slow Decarbonization case (CAGR 3.8 percent, 2034 average rate equal to 20.87 cents/kWh).[73] We note that the rates assumed in the load forecast do not incorporate the Government's May 16, 2024 announced Muskrat Falls rate mitigation plan, which is referenced in NLH's 2024 Resource Adequacy Plan Overview at page 19 and explained more fully in Appendix C at page 125.

---

65 Load Forecast Report, page 17 lines 15 to 19.

66 Load Forecast Report, page 17 lines 19 to 21.

67 Load Forecast Report, page 18 lines 1 to 7.

68 Load Forecast Report, Chart 8.

69 Heating degree days refers to the equivalent number of degrees Celsius a given day's mean temperature is below 18 degrees. Load Forecast Report, page 19, n. 44.

70 Load Forecast Report, page 19 lines 5 to 7.

71 Load Forecast Report, page 19 lines 5 to 9.

72 Load Forecast Report, page 19 lines 9 to 10.

73 Load Forecast Report, Table A-6.

Table 13: IIS Average Domestic Rate Forecast, excluding HST (cents/kWh)

Year	Slow Decarbonization	YoY Growth Rate	Reference Case	YoY Growth Rate	Accelerated Decarbonization	Growth Rate
2023	13.80	-	13.80	-	13.80	-
2024	14.99	8.62%	14.79	7.17%	14.79	7.17%
2025	15.95	6.40%	15.62	5.61%	15.62	5.61%
2026	16.52	3.57%	16.07	2.88%	16.07	2.88%
2027	17.01	2.97%	16.43	2.24%	16.43	2.24%
2028	17.51	2.94%	16.80	2.25%	16.80	2.25%
2029	18.03	2.97%	17.18	2.26%	17.18	2.26%
2030	18.57	3.00%	17.56	2.21%	17.56	2.21%
2031	19.12	2.96%	17.96	2.28%	17.96	2.28%
2032	19.68	2.93%	18.36	2.23%	18.36	2.23%
2033	20.27	3.00%	18.78	2.29%	18.78	2.29%
2034	20.87	2.96%	19.20	2.24%	19.20	2.24%
CAGR	**3.83%**		**3.05%**		**3.05%**	

8. LIS: Industrial Growth and Electrification

For the LIS Reference case, NLH assumes that the two major industrial customers in Labrador (Iron Ore Company of Canada and Tacora Resources Inc.)[74] will continue at current loads throughout the forecast period, with peak demand remaining at 320 MW through 2034.[75] The Medium Growth Scenario case assumes that both major industrial customers will move forward with expansion projects (leading to 2034 peak demand of 595 MW, an increase of 275 MW), while in the High Growth Scenario, those customers expand even further (resulting in 2034 peak demand of 1,060 MW, an increase of 740 MW).[76] NLH indicated that, as of the date of its load forecast, firm requests for transmission service in Labrador totaled 873.4 MW.[77]

9. LIS: Electric Vehicles

NLH also included assumptions about EV adoption in its LIS load forecast scenarios. The Reference case and Medium Growth Scenario case used the "EV Reference Case" described above regarding the IIS forecast.[78] (Notably, the "Slower EV Adoption Case" was not used.) The High Growth Scenario used the "Accelerated EV Adoption Case."[79] The impact on LIS peak

74 NLH Response to PUB-NLH-315 (b).
75 Load Forecast Report, page 21 lines 8 to 10; Chart 10.
76 Load Forecast Report, page 21 lines 10 to 13; Chart 10.
77 NLH Response to PUB-NLH-315 (a).
78 Load Forecast Report, page 20 lines 6 to 7.
79 Load Forecast Report, page 20 lines 7 to 8.

demand in 2034 is modest (+6.7 MW in the Reference and Medium Growth Scenario cases, and +7.9 MW in the High Growth Scenario case).[80]

D. Key Statistics/Considerations

The Load Forecast Report contains a large amount of information and data. In this section, we draw out some insights from that data.

1. **Even in the most conservative case, NLH is forecasting 160 MW of peak load growth on the IIS.** In the Slow Decarbonization case, NLH is forecasting 87 MW of peak load growth by 2030 and 160 MW by 2034.[81] The Reference case (growth of 126 MW by 2030 and 229 MW by 2034) and Accelerated Decarbonization case (growth of 204 MW by 2030 and 367 MW by 2034) are considerably higher.[82]

2. **Electric vehicle demand accounts for up to 41 percent of forecasted IIS peak demand growth by 2034.** The impact of forecasted electric vehicle adoption and consumption is an increase of between 65 MW (Slow Decarbonization case) and 113 MW (Accelerated Decarbonization case) of peak load in the IIS.[83] This accounts for between 31 percent and 41 percent of all forecasted IIS peak load growth, depending on the case.[84]

3. **Industrial customer growth is forecasted to have a moderate impact on IIS forecasted peak demand.** NLH expects that in the Slow Decarbonization case, about 38 percent (60 MW out of 160 MW) of peak load growth on the IIS is attributed to industrial customer growth through 2034.[85] In the Accelerated Decarbonization case, NLH forecasts peak demand growth related to industrial customers of 120 MW, which is about 33 percent of total forecasted peak demand growth of 370 MW.[86]

4. **NLH is forecasting IIS energy growth of at least 1.1 TWh, and up to 2.3 TWh by 2034.** IIS energy (in GWh) is forecasted to grow at CAGR of 1.0 percent (in the Slow Decarbonization case) and 2.1 percent (in the Accelerated Decarbonization case), driving between 1.1 and 2.3 TWh of additional energy needs over the next ten years.[87]

---

80 Load Forecast Report, Chart 9.

81 Load Forecast Report, Table A-4.

82 Load Forecast Report, Table A-4.

83 Load Forecast Report, Table 5.

84 Load Forecast Report, Table 5.

85 Load Forecast Report, Chart 8.

86 Load Forecast Report, Chart 1; Chart 8.

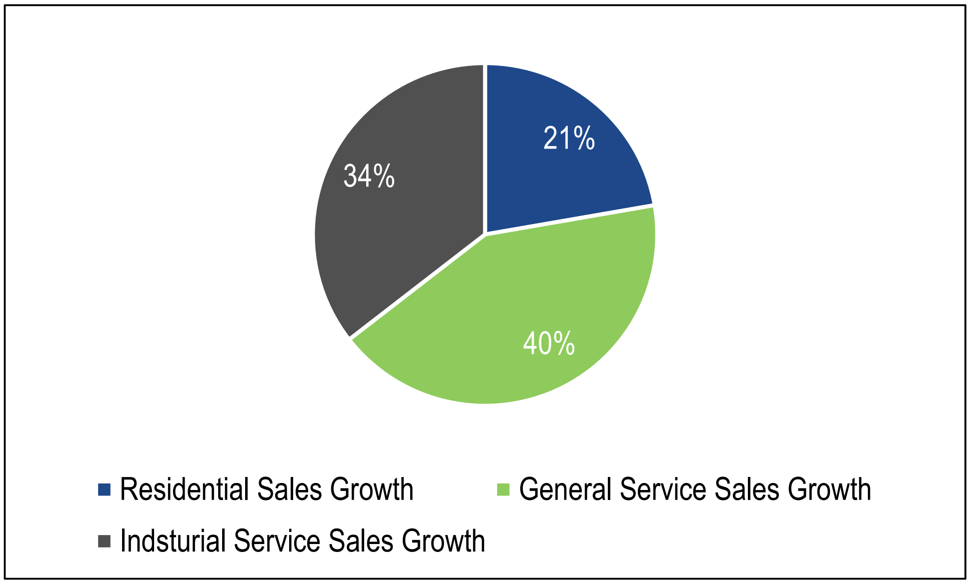
87 Load Forecast Report, Chart 13.

5. **The primary driver of IIS energy growth in the Slow Decarbonization case is General Service Sales growth.** Of the nearly 1.1 TWh of forecasted energy growth in the Slow Decarbonization case, about 40 percent (440 GWh) is forecasted to be from growth in General Services sales.[88] The remainder is made up of growth in industrial services sales (34 percent, 370 GWh)[89] and residential sales (21 percent, 232 GWh).[90]

6. **However, in the other cases (Reference and Accelerated Decarbonization), growth in residential sales is the primary driver of forecasted IIS energy growth**. Residential energy load is forecasted to grow by 605 GWh in the Reference Case and 922 GWh in the Accelerated Decarbonization case.[91] This represents 38 percent and 40 percent, respectively, of the total growth forecasted in those cases.[92]

Figure 3, Figure 4, and Figure 5 below show the share of forecasted energy growth for each major rate class across the three scenarios.

Figure 3: 2022-34 IIS energy growth forecast by service class – Slow Decarbonization



88 Load Forecast Report, Chart 13; Chart 15.
89 Load Forecast Report, Chart 13; Chart 16.
90 Load Forecast Report, Chart 13; Chart 14.
91 Load Forecast Report, Chart 14
92 Load Forecast Report. Chart 13; Chart 14.

Figure 4: 2022-34 IIS energy growth forecast by service class – Reference

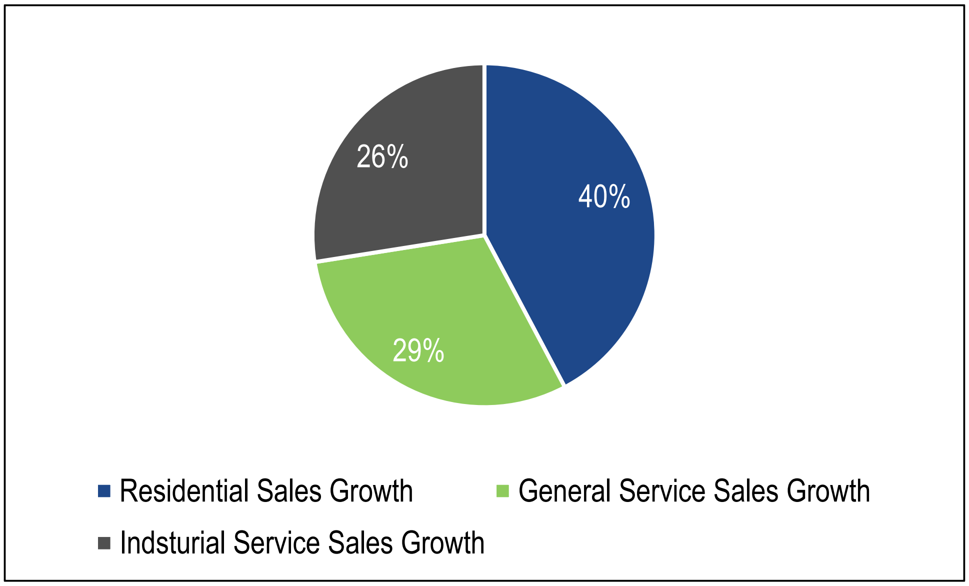
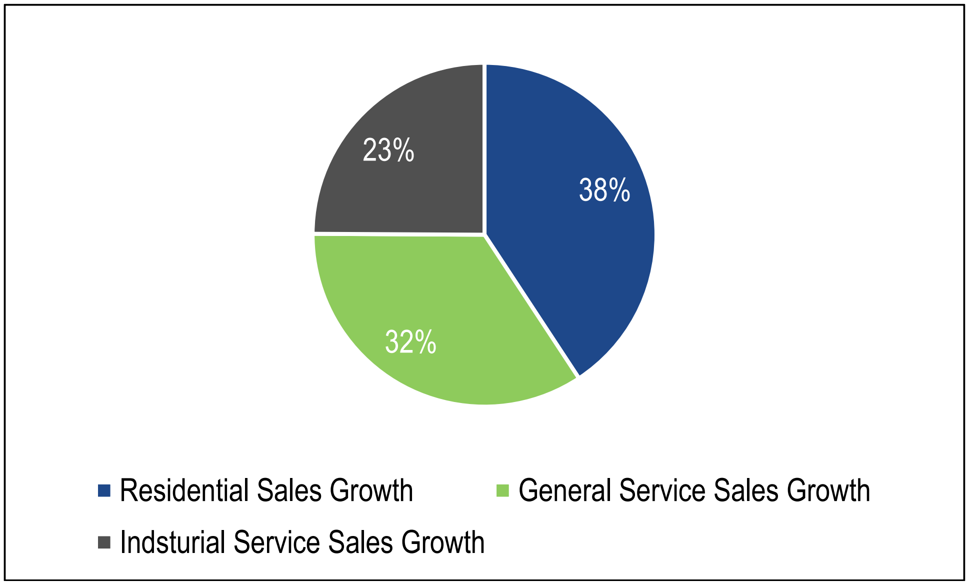


Figure 5: 2022-34 IIS energy growth forecast by service class – Accelerated Decarbonization



7. **Most energy and peak demand growth is forecasted to occur by 2030.** The IIS forecast shows that between 54 and 56 percent of peak load growth and 60 to 69 percent of energy growth is forecasted to occur by 2030, depending on the load

scenario.[93] The same is true for the Reference and Medium Growth cases for the LIS forecast, where 72 to 81 percent of peak load growth is expected to occur by 2030.[94] Only in the LIS High Growth case does most peak load growth (492 MW out of 762 MW, or 64.6 percent) and energy growth (3,622 GWh out of 5,316 GWh, or 68.1 percent) occur after 2030.[95]

8. **The LIS forecast anticipates almost zero or near zero growth in both peak and energy demand through 2029 in all cases.** NLH noted in the Load Forecast Report that "the existing transmission system in Labrador is fully maximized and it has been assumed that this constraint will not be resolved until at least 2029. As such, forecast growth is anticipated to occur after 2029."[96]

9. **Industrial load growth is by far the largest determinant of future peak demand and energy growth in the LIS, and NLH's three scenarios forecast wide ranges of potential future load.** LIS industrial energy growth is forecasted to be as high as 5.3 TWh by 2034 (High Growth case), compared to just 0.125 TWh of combined residential and general service growth in the High Growth case.[97] Additionally, the forecast for industrial energy growth varies widely, with the Reference case assuming zero growth, the Medium Growth case assuming 2.0 TWh of energy growth, and (again) the High Growth case assuming 5.3 TWh of energy growth.[98] The impact of these differences across the cases can be seen in the peak demand forecast as well, with overall peak demand (across all rate classes) forecasted to increase by only 36 MW in the Reference case but by 762 MW in the High Growth case.[99]

10. **Electric Vehicle Load is forecasted to add between 390 GWh and 670 GWh of energy usage by 2034.[100]** Energy growth from electric vehicle demand represents between 31 percent (Accelerated Decarbonization case) and 38 percent (Reference Case) of IIS energy growth through 2034.[101] The electric vehicle energy demand

93 Load Forecast Report, Table A-4.

94 Load Forecast Report, Table A-5.

95 Load Forecast Report, Table A-5.

96 Load Forecast Report, page 37, lines 5 to 7.

97 Load Forecast Report, Charts 19, 20.

98 Load Forecast Report, Chart 20.

99 Load Forecast Report, Table A-5.

100 Table 5 in the Load Forecast Report proports these numbers as the IIS "System Requirements in 2034." Due to the current lack of EV usage and thus energy consumption in NL, we assume these numbers represent growth expected by 2034.

101 Electric vehicle energy demand growth totals 37 percent of total IIS energy growth in the Slow Decarbonization case. Load Forecast Report, Table 5.

impacts both the residential and general service rate classes.[102] In the residential rate class, almost 100 percent of residential load growth in the Slow Decarbonization case through 2034 is attributed to EVs, while about half of residential load growth in the Reference case is attributed to EVs.[103]

11. **Assumptions regarding carbon/GHG emissions pricing is constant across all load forecast scenarios, and thus has no impact on the results of each case relative to the others.** NLH confirmed that it used the same set of annual carbon emissions prices in all scenarios.[104] Thus, while it is an important assumption to the load forecast process overall and can have a significant impact on both energy and peak demand, assumptions around carbon emissions pricing explains no differences between the load forecast scenario cases.

12. **Daymark provided useful recommendations that NLH should endeavor to address.** For example, Daymark suggested expanded scenario analyses and enhanced consideration of electricity price elasticity through iterative modeling.[105] These are good recommendations that NLH should incorporate into future load forecasting efforts and reporting.

III. Bates White Assessment of Load Forecast Report

A. Residential and General Service Forecasts

1. IIS Residential and General Service

Bates White reviewed the methods, assumptions and results of NLH's forecasts of residential and general service loads for the IIS, drawing on information in the Load Forecast Report; the study attached to that report, "R&RA 2024: Independent Load Forecasting Process Review," completed by Daymark Energy Advisors; and data and responses provided by NLH to Bates White information requests.

NLH relies primarily on econometric regression analysis to produce forecasts of residential and general service energy usage and peak demand on the IIS.[106] Historical data for key variables are used to estimate the extent to which the variables explain energy usage and peak demand

[102] Load Forecast Report, section 4.1.1-4.1.2.

[103] Load Forecast Report, page 31 lines 1 to 5.

[104] NLH Response to PUB-NLH-316 (a).

[105] Load Forecast Report, Attachment 1, Section III.

[106] Load Forecast Report, Appendix B.

over time (a historical period from 1977 through 2022). The estimated regression coefficients are then used to estimate energy and peak demand using forecasted values of the input variable data.

A significant majority of residential and general service energy usage and peak demand on the IIS is associated with serving load on the Newfoundland Power ("NP") system. For example, the 2022 winter peak load (excluding industrial load) for the IIS was approximately 1,571 MW, of which approximately 1,426 MW (91%) was from load on the NP system.[107] Similarly, residential energy usage on the NP system was approximately 3,415 GWh in 2022, representing 93% of the IIS total of approximately 3,655 GWh.[108] General service load would be expected to follow this pattern, but Bates White was unable to validate this, as the detailed data provided by NLH excluded a portion of general service load on the NP system. Specifically, NLH provided data for NP general service energy load for customers with electric heat (coded as "AEGS"), but no data for other NP general service load, which we infer explains the difference in energy data totals compared to reported values in the Load Forecast Report.

Econometric regression analysis is an industry standard methodology applied in utility load forecasting. Bates White did not conduct a detailed comparative assessment to determine whether NLH's *execution* of the methodology would be considered to meet industry standards. However, we have some observations on methods, data, and presentation that could be used to improve NLH's reporting, and possibly its load forecasts.

In addition to the specific observations described below, we note that the load forecast is now relatively old, particularly considering the significant changes in load drivers identified by NLH. Our understanding is that there is an ongoing study by the Posterity Group, a consultant for Hydro and Newfoundland Power, to update the load potential study done by Dunsky in 2019. The Posterity Report is expected to be completed in the third quarter of 2024. The load forecast should be reviewed in light of the Posterity report to determine any implications for the load forecast, particularly as it relates to electrification.

Recommendation #1: *Given a) the importance of NLH load forecasting to the determination of future resource need; b) the changing drivers of energy demand reflected in the Load Forecast Report; c) the fact that the load forecast was conducted before 2023 actual data were available; and d) there is an ongoing study by a consultant for Hydro and Newfoundland Power to update the load potential study done by Dunsky in 2019, we recommend that NLH review its load forecasts and update them for significant changes identified in the review and/or by the consultant study.*

[107] NLH Response to PUB-NLH-311, attachment 'PUB-NLH-311-Attachment 1_Revision1.xlsx'
[108] *Id.*

2. Reporting

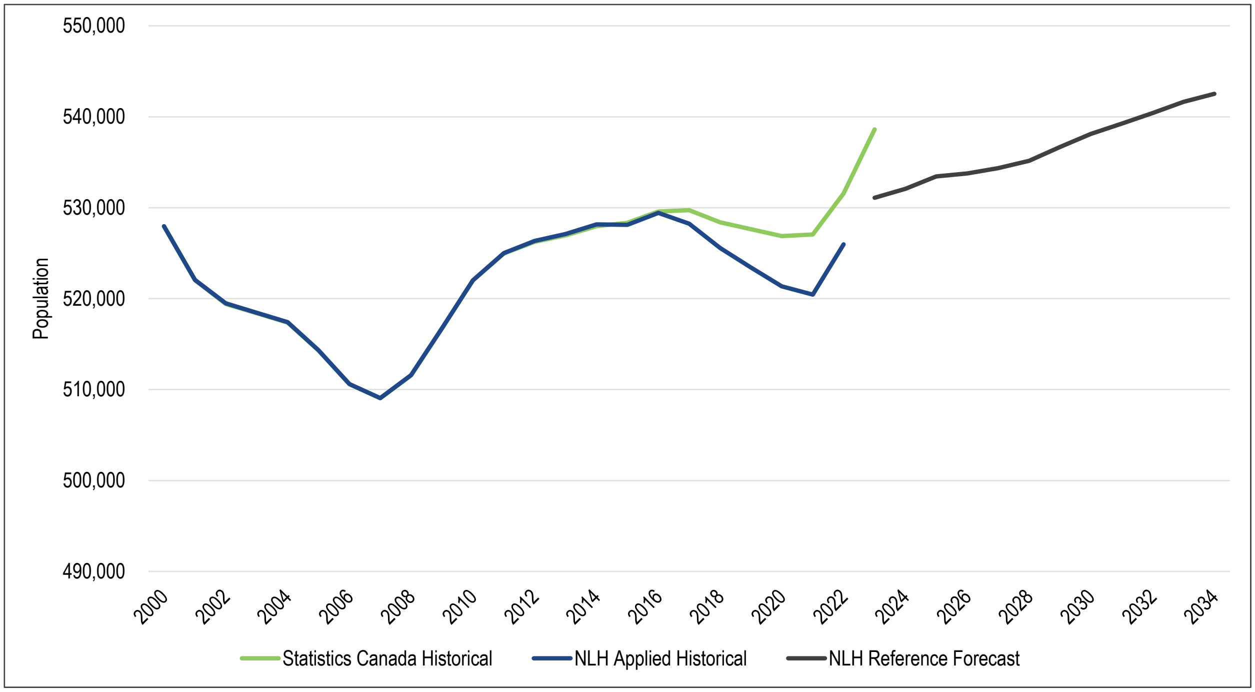
The Load Forecast Report would be improved with greater clarity and discussion of the drivers of the energy and peak demand forecasts. Definitions of component loads – e.g., the definition of general service load – and other terms referenced in the report would be helpful, as would a more detailed description and discussion of key drivers of the forecasts. For example, the relationship and relevance of population growth and customer counts, which we discuss below, would provide greater clarity regarding trends over the historical period compared to those projected for the future. We also recommend at least some characterization of the relevance of the energy and peak demand forecasts to future system needs and the RRA Study Review.

3. Population and Customer Count

As noted above, NLH incorporates population growth data and projections into its load forecasting. NLH uses historical population data to calculate regression estimates, and then applies population forecasts from the provincial government as inputs for the forecast period. We identified a discrepancy in the historical population data applied by NLH in its regression analysis and the historical population data currently available from Statistics Canada. The annual population values from the two series are identical for the period 1977 through 2000, but then diverge starting in 2001. The two population data sets are shown in Figure 6, along with the Reference population forecast applied by NLH.[109] The differences in historical population data are small through 2016 (such that they are not visible in the figure), but grow significant in more recent years, rising to a deviation of about 1%. This is significant, and should be explained and, if appropriate, corrected by NLH.

[109] NLH Response to PUB-NLH-311, attachment 'PUB-NLH-311-Attachment 1_Revision1.xlsx'; Statistics Canada, "Table 17-10-0005-01 Population estimates on July 1, by age and gender," https://doi.org/10.25318/1710000501-eng.

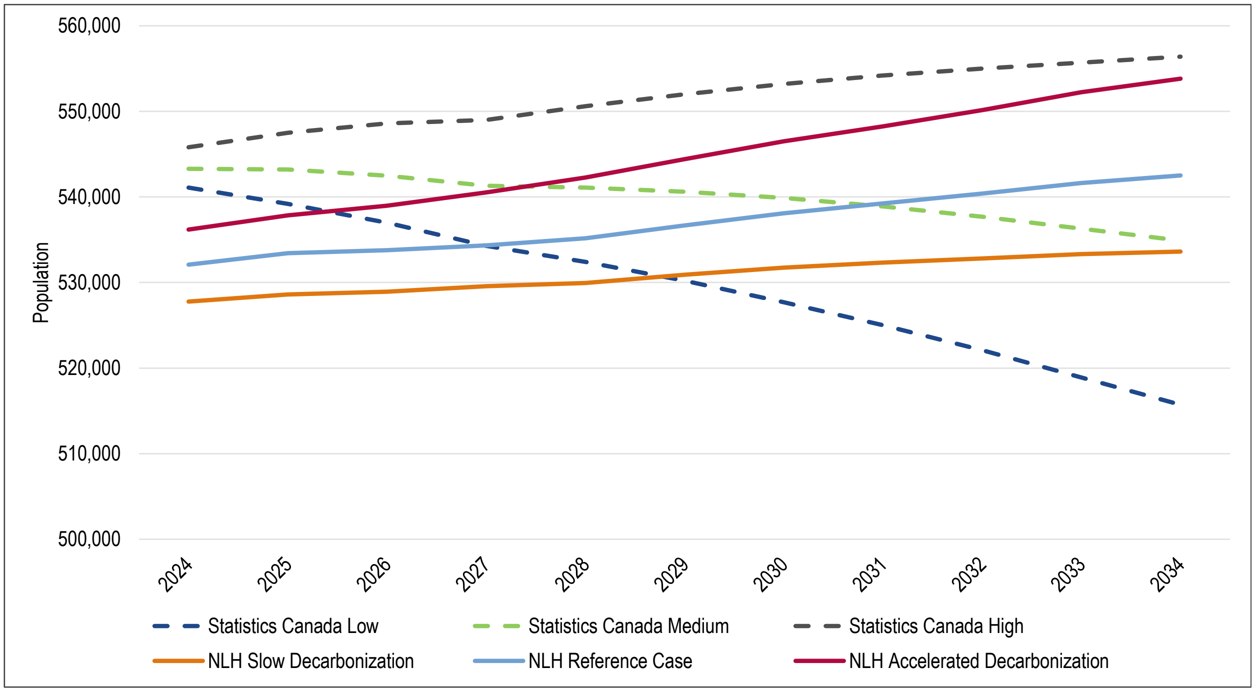
Figure 6: Population data comparison



Another issue of concern relates to the range of population projections applied by NLH in its load forecasts. All three of the NLH cases anticipate positive population growth. In contrast, Statistics Canada has a much wider range of forecast cases for the province. Figure 7 shows a comparison of the three NLH population growth series and the three main forecasts from Statistics Canada.[110]

[110] NLH Response to PUB-NLH-311, attachment 'PUB-NLH-311-Attachment 1_Revision1.xlsx'; Statistics Canada, Table 17-10-0057-01, "Projected population, by projection scenario, age and gender," as of July 1, https://doi.org/10.25318/1710005701-eng.

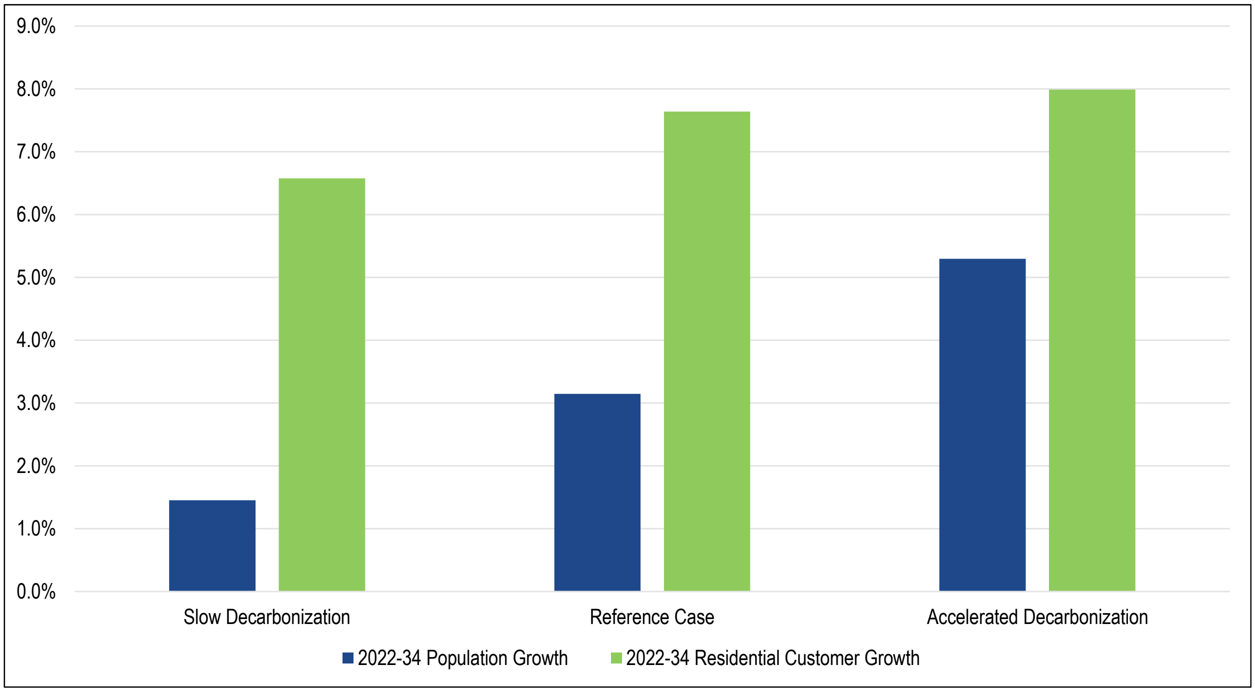
Figure 7: Comparison of population forecast cases, Statistics Canada and Newfoundland and Labrador Finance Department



Based on the historical data discrepancy issue described above, there may be a difference in the implicit starting point of the two forecasts. Regardless, it is clear that the Statistics Canada cases have a much wider range of futures – two of which show falling population between 2024 and 2034. The NLH cases cluster closer together and provide less distinction between potential futures. Bates White concludes that NLH should provide a fuller discussion and justification for the selection of the given population cases applied in its load forecasts. In general, it would be more useful to have a wider range of cases. One option would be to adopt cases from the Statistics Canada forecast set, which, in addition to the three main cases shown in Figure 7, include seven other population cases.

A final observation related to population is that residential customer count grows significantly faster than population in the NLH projections. This is significant as customer count is more relevant to load than population estimates. The percent changes for population and IIS residential customer count from 2022 to 2034 used in the NLH forecast data are shown in Figure 8.

Figure 8: Comparison of Population and Residential Customer Count Growth Rates[111]



This higher growth rate for customer count compared to population reflects a long-term trend in which residential customer count as a share of total population has grown significantly over time. In 1977, IIS residential customer count as a percentage of total population was about 23%, and by 2022 it had grown to 49%.[112] This may reflect demographic changes, including an aging population (with fewer children at home) migration from rural to urban areas, decreased birth rates (more people living singly or as a couple with no children). However, this trend continues through the forecast period, and it is important to note that the historical trend cannot continue without end. At some point, changes in customer count will align more closely with population growth, or contraction.

Recommendation #2: *In its forecast update, NLH should assess the impact of flat population growth and the associated impact on customer count, consistent with low population growth scenarios evaluated by Statistics Canada.*

[111] *Supra* note 107.

[112] NLH Response to PUB-NLH-311, attachment 'PUB-NLH-311-Attachment 1_Revision1.xlsx'; Statistics Canada, "Table 17-10-0005-01 Population estimates on July 1, by age and gender," https://doi.org/10.25318/1710000501-eng.

4. Electricity Rates

Projected electricity rates are inputs to NLH's regression-based load forecasting. As noted above, the assumed future rates reflected in the load forecast are not consistent with the Government's May 16, 2024 Muskrat Falls rate mitigation plan, which is referenced in NLH's 2024 Resource Adequacy Plan at page 19.

With respect to electricity prices, we recommend NLH reconcile and potentially update its load forecast to account for the Government's May 16, 2024 Muskrat Falls rate mitigation plan, which differs from the electricity prices modeled in the load forecast. NLH should address this inconsistency and review the associated impact on its forecasts, updating the forecasts as appropriate.

Recommendation #3: *With respect to electricity prices, we recommend NLH reconcile and potentially update its load forecast to account for the Government's May 16, 2024 Muskrat Falls rate mitigation plan, which differs from the electricity prices modeled in the load forecast.*

5. Electric Vehicles

NLH contracted Dunsky Energy and Climate Advisors to conduct an EV Adoption and Impacts Study. EV adoption in the province was forecast using Dunsky's Electric Vehicle Adoption ("EVA") model, under various scenarios reflecting different federal and provincial policy, incentive programs and technology availability conditions.

Separate estimates of likely EV adoption, impacts on annual energy consumption (GWh), and hourly demand (MW) were developed for the Island and Labrador zones and their respective integrated electrical systems. Three separate scenarios were considered, focused on different policy, market, and technology conditions, resulting in forecasts for Low, Medium, and High EV adoption growth.[113]

The vehicle market was segmented by vehicle and usage characteristics into Light-Duty Vehicles ("LDV"), Medium-Duty Vehicles ("MDV") and Heavy-Duty Vehicles ("HDV"). The LDV market consisting of passenger cars, Sport Utility Vehicles ("SUVs") and light trucks (including pickup trucks) used for personal transportation and commercial use. Both BEVs and PHEVs were included in the LDV segment. The MDV segment is largely comprised of urban or regional delivery vehicles with consistent daily usage with high overall annual driving distances. And the HDV segment for trucks used for either long-haul or other vocational applications (e.g., dump trucks) with special technical characteristics such as range and payload requirements. Passenger buses were considered separately for reporting purposes.[114]

[113] Load Forecast Report, Attachment 2, p.13.

[114] Load Forecast Report, Attachment 2, p.9.

The Dunsky's EVA Model starts by assessing the maximum theoretical potential for deployment of the various types of vehicles considering the size of the market and its composition by vehicle class. It narrows that potential first by finding the unconstrained economic potential EV uptake by considering the incremental purchase cost of an EV over an internal combustion engine ("ICE") vehicle, the relative total cost of ownership (or internal rate of return) of both types of vehicles, and considering O&M and fuel costs operate the vehicles. Next the model accounts for non-economic constraints, such as range anxiety and charging access. The model then finally uses technology diffusion theory to estimate rate of adoption considering market competition between EV types (BEV vs PHEV).[115] More specifically, the EVA model uses Bass diffusion to model the impact of electric vehicle prices on consumer uptake.[116]

The underlying assumptions of a Bass Diffusion Model can be expressed as follows: "*The probability of adopting by those who have not yet adopted is a linear function of those who had previously adopted.*"[117] Its mathematical representation is a simple differential equation that describes the process of how new products get adopted in a population. The model presents a rationale of how current adopters and potential adopters of a new product interact. The basic premise of the model is that adopters can be classified as innovators or as imitators, and the speed and timing of adoption depends on their degree of innovation and the degree of imitation among adopters. In summary, Bass curve models take historic data and an end point and use the past to estimate a midpoint and growth rate in the future. In the early stages of growth, Bass models can be too aggressive and small changes in numbers can have a major impact. As more and more historical data points become available, the forecasting accuracy of Bass models increases.

The EV Adoption and Impacts Study states that the model was calibrated using "historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment to benchmark the model to historical adoption and calibrate key model parameters to local market conditions."[118] A potential source of inaccuracy is that only approximately 400 EVs have been purchased in the province since 2017.[119]

In response to Bates White's inquiry as to whether only NL-specific data was utilized or if data from other provinces further along in transportation electrification was used as well, and

---

[115] Load Forecast Report, Attachment 2, p.12

[116] NHL Response to PUB-NLH-319.

[117] Sungjoon Nam, "Demystifying the Bass Diffusion Model: the hidden role of distribution channel," *Rutgers Business School*, February 2011, https://web-docs.stern.nyu.edu/marketing/SNamPaper.pdf.

[118] Load Forecast Report, Attachment 2, p.13.

[119] At the time of the EV Adoption and Impacts Study, Dunsky attributed lagging EV adoption to lack of charging infrastructure; lower and later financial incentives for the purchase of EVs compared to other provinces; and limited availability of EVs to purchase at local dealerships; Load Forecast Report, Attachment 2, p.10.

how province-specific characteristics (such as typical driving distances, disposable income, and colder climate) were considered, NLH in consultation with Dunsky responded that "The model was specifically built using data from Newfoundland and Labrador and did not include data from other provinces."[120]

A literature survey of EV adoption modeling techniques found diffusion modeling (including Bass) to be used in a small minority of EV adoption studies. Approaches favored over diffusion include agent based or discrete choice.[121] NLH (and Dunsky) did not respond to the request for an explanation of the advantages of diffusion modeling technique over agent based or discrete choice. Instead, NLH's response simply observed that "the Electric Vehicle Adoption model used by Dunsky is not purely a diffusion model and does not use a single approach but adapts multiple technical elements to create a forecast, including expert guidance."[122]

6. Key uncertainty factors in EV adoption forecast

The key drivers of Dunsky's estimate of the unconstrained economic potential uptake of EVs include vehicle initial cost, mainly attributable to battery cost, lifetime operational cost, and associated willingness to pay by the potential buyers. Among the main constraints to adoption identified by Dunsky were range anxiety and charging availability; the later referring to both home and public chargers.

While the prevalence of single-family homes in Labrador bodes well for the feasibility of home charging there, government support in developing public charging infrastructure will be crucial to the speed of EV adoption, given the importance of range anxiety as a barrier to acceptance of EVs, particularly in very cold climates. A 2023 study by US EV charging company FLO found that 60% of EV drivers rely on fast chargers when they're on "extended trips," suggesting that fast charging is "needed for most EV drivers" and that almost one third don't have a charger at home.[123] The latter is particularly relevant in the larger Island EV market given the higher prevalence of Multi-Unit Residential Buildings ("MURBs"). Worthy of note is that all three EV growth scenarios consider limited home charging access in MURBs: 6%, 20% and 40% in the low, medium, and high growth scenarios; respectively.[124]

The importance of the widespread availability of fast EV chargers has been demonstrated in Norway, the country with the highest share of EVs. Over the course of a decade, Norway

---

[120] NLH Response to PUB-NLH-322 (a).

[121] Lucy Maybury, Padraig Corcoran, and Liana Cipcigan, "Mathematical modelling of electric vehicle adoption: A systematic literature review," *Transportation Research Journal*, May 2022.

[122] NLH response to PUB-NLH-320; Load Forecast Report, Attachment 2, pp. 49–55.

[123] "Survey Says: Most EV Drivers Rely on Fast Chargers for Long Trips, Use Onsite Amenities While Charging," *Flo*, March 14, 2024, https://www.flo.com/news/survey-says-most-ev-drivers-rely-on-fast-chargers-for-long-trips-use-onsite-amenities-while-charging/.

[124] Load Forecast Report, Attachment 2, pp.24-26.

pursued the deployment of public charging ports as one of the cornerstones in its transportation decarbonization efforts as can be seen in Table 14 below.[125]

Table 14: Norway's EV charger deployment efforts 2010 through 2018

Up to 2010	2010-2011	2012-2014	2015-2017	2018
Few hundred public chargers, people used available outdoor domestic plugs.	First public support infrastructure program comes out, supplying normal chargers to requested areas, then fast chargers with remaining program moneys.	National support program of fast chargers, 40% of new chargers would be fast, and municipalities would begin to install free to use public normal chargers.	Networks established on major roads, 2 fast and 2 semi-fast chargers every 50km, teaming up with fuel stations and fast-food restaurants, giving contracts to lowest bidder and cities provide free chargers.	Full fast charger coverage along all major roads complete.

In 2021, NLH completed the first provincial network with 14 fast-chargers on the island to increase electrification of the transportation sector and thereby reduce GHG emissions[126]. Upon announcing the completion of the initial 14 fast-charger network, NLH announced that over the next three years, it would expand the charging network, educate the public, execute programs that promote electric vehicle ownership, and support the provincial government through facilitation of customer rebates. While Hydro has allocated approximately $2 million in its Five-Year (2025-2029) Capital Plan for additions to the fast-charger network, no information is available regarding the specific number and locations of additional EV charging stations.

Dunsky's assumptions regarding EV initial costs, particularly battery costs, may be somewhat dated in light of further reductions in the cost of batteries as the market has recently been introduced to new and cheaper battery chemistry formulations by Tesla and other EV manufacturers. A 2023 study by the Rocky Mountain Institute (RMI) "expects battery costs to halve this decade, from $151 per kilowatt hour (kWh) to between $60 and 90 per kWh."[127] According to RMI, by 2030, falling costs will, for the first time, make EVs as cheap or cheaper to both buy and run as petrol cars in every market globally. RMI's study also found that economics is now overtaking policy incentives as the core accelerant of EV sales, with falling

[125] Erik Figenbaum, "Norwegian EV Charging Infrastructure and User Experiences," *Institute of Transport Economics*, May 2, 2019, https://www.nationalacademies.org/documents/embed/link/LF2255DA3DD1C41C0A42D3BEF0989ACAECE3053A6A9B/file/DCDBC621E1BE55C366D3F8EB2522C002E5D542B77B86?noSaveAs=1.

[126] Lukas Wall, "Completion of 1st fast-charging network 'just the beginning' for electric car owners in N.L.," *CBC*, August 30, 2021, https://www.cbc.ca/news/canada/newfoundland-labrador/ev-fast-charger-network-complete-1.6157101v.

[127] "EVs to surpass two-thirds of global car sales by 2030, putting at risk nearly half of oil demand, new research finds," *Rocky Mountain Institute*, September 14, 2023, https://rmi.org/press-release/evs-to-surpass-two-thirds-of-global-car-sales-by-2030-putting-at-risk-nearly-half-of-oil-demand-new-research-finds/.

battery costs being the lead driver.[128] Another factor considered in Dunsky's forecast is the available vehicle supply. Since the Dunsky study was conducted, several manufacturers have introduced lower cost EV models which, all things being equal, will also help accelerate EV adoption rates.[129]

7. EV Energy and Demand Forecast

Dunsky's EV Study presents a wide range of possible outcomes, but the overall scale of the EV transformation in Newfoundland and Labrador is significant under all scenarios. By 2040 Dunsky expects the province will have between 100,000 and 200,000 LD EVs in circulation plus another 10,000 to 14,000 MHD EVs.[130] Certain segments have the strongest potential for electrification, such as buses and medium-duty delivery trucks. Yet others have greater uncertainty depending on technological advancements in vehicle manufacturing, such as long-haul heavy-duty trucks. While the forecast of EV penetration is significant, the EV growth in Newfoundland and Labrador will continue to lag behind the rest of Canada as summarized below.

Light duty EV adoption is expected to have a significant impact on load growth in Newfoundland and Labrador, increasing load by 480 – 1,000 GWh by 2040.[131] By 2040, light duty EVs will contribute 170 - 340 MW to peak demand in the winter at 10PM if unmanaged.[132] For example, in the Aggressive Growth Scenario, the EV load would peak at 10pm (340 MW) if unmanaged, while, if managed the peak would shift to 1am (385 MW), depending on the load management strategy.[133]

None of the three light duty EV uptake scenarios modeled by Dunsky achieve the 2035 Newfoundland and Labrador EV targets (100% of sales). The High Growth Scenario is the closest to this goal, reaching 65% of new LDV sales by 2035, assuming: aggressive expansion of public charging; increased economic incentives; high EV local availability; and actions to increase home charging in MURBs.[134] Under the Medium Growth Scenario EV sales would only be expected to reach 48% of new vehicle sales by 2035 and, under the Low Growth Scenario the

[128] Ibid.

[129] John Vincent and Cherise Threewitt, "How Much Do Electric Cars Cost?", *U.S. News and World Report*, March 2024.

[130] Load Forecast Report, Attachment 2, pp.24-26, 34-36.

[131] Load Forecast Report, Attachment 2, p.28.

[132] Load Forecast Report, Attachment 2, p.56.

[133] Load Forecast Report, Attachment 2, p.58.

[134] Load Forecast Report, Attachment 2, p.26.

EV share of new vehicle sales would be even lower, reaching only 35% of new sales by 2035.[135] Table 15 below shows the impacts of LDV EV stock on demand and peak energy.[136]

Table 15: 2040 Energy and demand LDV EV contribution to NFL load

Case	Energy [MWh]	Demand [MW]	Occurrence
Low Growth Scenario	480	170	10:00 PM
Low Growth Scenario - Managed	480	190	12:00 AM
Medium Growth Scenario		250	10:00 PM
Medium Growth Scenario - Managed		280	1:00 AM
High Growth Scenario	1,000	340	10:00 PM
High Growth Scenario - Managed	1,000	385	1:00 AM

While not nearly as large as the potential impact of light duty EVs, MHD EV adoption could have a significant impact on load growth in Newfoundland and Labrador, increasing load between 450 and 615 GWh and 125 - 175 MW to the winter peak demand by 2040.[137] The peak demand imposed by MHD EVs is expected to occur at 6 pm in all seasons, offering little opportunity for management, due to less flexible charging windows for MHD fleets, with both vehicles and infrastructure designed based on range requirements and the available down time for charging. The impacts of MHD EV stock on demand and peak is shown below in Table 16.[138]

Table 16: 2040 Energy and demand MHD EV Contribution to NFL load

Case	Energy [MWh]	Demand [MW]	Occurrence
Low Growth Scenario	450	125	6:00 PM
Medium Growth Scenario			6:00 PM
High Growth Scenario	615	175	6:00 PM

In all scenarios, EV adoption rates and the associated impact on peak demand and energy sales rise slowly at first, not reaching significant levels until after 2030 as can be observed in Figure 9 and Figure 10 below.

[135] Load Forecast Report, Attachment 2, pp.24-25.
[136] Load Forecast Report, Attachment 2, pp.56-58
[137] Load Forecast Report, Attachment 2, pp.37-38.
[138] Ibid

Figure 9: EV charging demand at IIS peak[139]

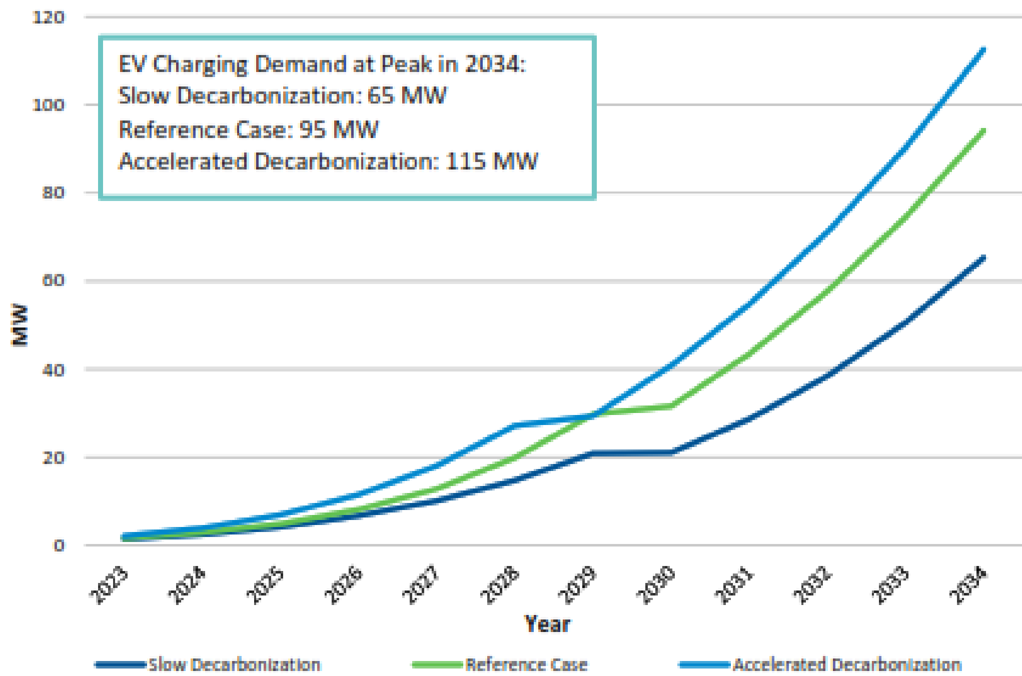
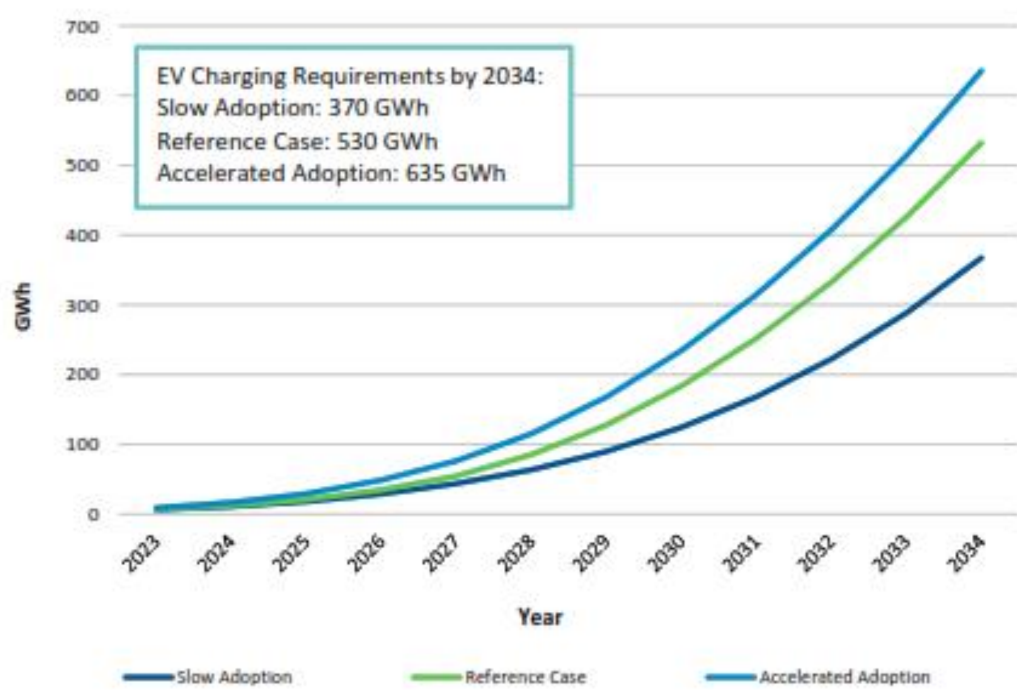


Figure 10: IIS EV charging energy requirements[140]



[139] Load Forecast Report, reproduction of Chart 3, page 9.

[140] Load Forecast Report, reproduction of Chart 4, page 10.

Recommendation #4: *NLH should detail the assumptions underpinning the EV scenarios it adopts, addressing the fact that projected penetration rates reflected in the load forecast fall short of Newfoundland and Labrador provincial targets, and the timing and extent to which growth in charging infrastructure will be achieved.*

8. Electrification of building space heating, Conservation, and Energy Efficiency

Over the last ten years, numerous MSHPs have been installed in homes already heating with electric resistance heat. A recent survey indicates that over 28 percent of homes have installed MSHPs.[141] More recently, provincial and federal government funding programs have targeted homes that do not have electricity as the primary heating source, to supplement or replace their existing heating source with electric heat. As space heating continues to electrify, growth in electricity use on the island, driven by switching from oil or wood to electric heat, will be partially offset by greater penetration of energy-efficient heat pumps in electrically heated homes. A large number of conversions to electric space heating from other fuels may result in increased peak demand in the winter, and the strong uptake of MSHP may also result in increased demand in the summer to meet cooling needs.

One way to reduce or avoid the increase in winter peak demand resulting from heat pump installation could be to allow participants engaged in conversion to electric heat to maintain their fossil fuel heating system as backup or supplemental heat to be used during very low temperature events. In response to a Bates White information request regarding conditions for receiving heat pump participation incentives, NLH responded that "for the oil-to-electric conversions detailed in the [Load Forecast Report], a mix of electric heating systems was assumed and there was no assumption made about consumers being allowed to maintain their non-electric heating system as a backup heating source."[142] However, NLH has assumed that the electric heating source would be their primary heat source and any heating provided by their potential backup heating source would not have a material impact on the load forecast.[143]

a) Energy and Demand Impact Forecast of Oil-to-Electric Conversions

For the 2023 Load Forecast modelling process, NLH considered decarbonization factors in the development of forecast scenarios that include government policy (including mandates and regulations), available incentives and the price of carbon greenhouse gas emissions. Three distinct decarbonization scenarios were developed: a Reference Case, a Slow Decarbonization

[141] Load Forecast Report, page 16 line 12 to page 17 line 1.

[142] The most recent update of the provincial Oil to Electric Incentive Program requires participants to remove oil tanks; however, historically, there was no removal requirement for participants. Such removal is also not required by the current federal Greener Homes Program. NLH Response to PUB-NLH-314 (b).

[143] NLH Response to PUB-NLH-314 (b).

Scenario, and an Accelerated Decarbonization Scenario. Different conversion rates of oil-heated homes with an oil tank expiring during the forecast period to electric heat were assumed in each case: 59% for the Slow Decarbonization Case; 71% for the Reference Case; and, 100% in the Accelerated Decarbonization Scenario.[144] The conversion oil-to-electric heating systems in Government buildings was assumed to be modest in the Slow Decarbonization and Reference Case plus an additional 40% in the Accelerated Decarbonization Scenario.[145]

b) Key uncertainty factors in the forecast of Oil-to-Electric Conversions

The government policy (including mandates and regulations) assumed in each load forecast scenario possibly represent the largest source of uncertainty in the forecast of conversion from oil to electric heating.

The forecast of adoption of heat pumps in electrically heated homes was primarily based on historical uptake with the impact of the Government of Canada's "Canada Greener Homes Initiative" taken into consideration.[146] Newfoundland Power Inc.'s April 2023 Load Forecast for heat pump adoption was also reviewed and considered during the development of the load forecasts.

The available incentives referenced in the Load Forecast Report were limited to two programs: The Government of Canada's Greener Homes Grant and the provincial government's implementation of a new fuel switching and energy efficiency incentive program in collaboration with Natural Resources Canada and Environment and Climate Change Canada.[147]

Within the Slow Decarbonization Scenario and the Reference Case, it was assumed that existing program funding would be available until 2030.[148] However, in the Accelerated Decarbonization Scenario, no such assumption was made as customer incentives would no longer be required because of the assumed policy requirements that households convert to an electric heating system when their oil tank expires.

In the Reference Case and Slow Decarbonization Scenario, it was not assumed that a policy would exist that would require households or building owners to install an electric heating system when their current oil tank expires or require new construction to be electrically heated. In the Accelerated Decarbonization Scenario, it was assumed that a policy would be in place that would require households to convert to an electric heating system when their oil tank expires.[149]

---

[144] Load Forecast Report, page 14 line 11 to page 15 line 1.

[145] Load Forecast Report, page 14 line 13 to page 15 line 7.

[146] Load Forecast Report, page 14 n.32.

[147] Load Forecast Report, page 14 n.32 and n.33.

[148] Load Forecast Report, Chart 7.

[149] Response to IR PUB-NLH-316 (b).

In its Load Forecast Report, NLH provides no information regarding the peak demand and energy impact of conversion of oil-to-electric heating but only reports the expected number of residential oil-to-electric conversions in aggregate for Labrador and Newfoundland systems.

While NLH does not provide estimates of the number of oil-to-electric heating conversions that would retain oil heating back up heat, the overall number of conversions is large enough to warrant such an estimate, as purely resistive heating back up could add significantly to winter peak demand.

Recommendation #5: *NLH should provide detail on key assumptions and their effects in its reporting, including details of oil-to-electric conversion programs made available to customers, the ability of customers to retain oil heating systems as backup, and the potential reliance on electric (i.e. resistive heating) backup to electric heat pumps.*

c) Conservation and Energy Efficiency

The forecast for energy savings used by NLH in its Load Forecast Report is based on estimated energy savings through utility conservation programs forecast by takeCHARGE. The same estimate was incorporated into all three load forecast scenarios.[150] This is problematic because the three scenarios consider varying levels of electrification of space heating, which could benefit from commensurate levels of building thermal efficiency retrofits to balance the increase in electric load caused by the addition of electric heating.

In its Load Forecast Report, NLH does not provide details on how the estimate of number of oil-to-electric conversions is used to estimate the incremental impact on peak demand and energy resulting from the conversions. Nor does NLH provide the assumptions made as to the building thermal efficiency of the converted homes used in its load forecast.

Based on the information provided in both the Load Forecast Report and the responses to questions from Bates White, it is impossible to proffer a definitive opinion on the significance of not having accurate estimates of building heating electrification on the overall load forecast for Newfoundland and Labrador. The significant number of conversions projected by NLH suggest the need for better coordination between oil-to-electric conversion requirements and efficiency programs offered in the province.[151]

[150] Load Forecast Report, page 16 lines 9 to 11.

[151] A 2021 study by Efficiency Canada found that if insulation was improved "fairly significantly" for Canada's entire building stock, the country's buildings would actually use less electricity, even if their heating systems were fully electrified. Brendan Haley and Ralph Torrie, "Canada's Climate Retrofit Mission," *Efficiency Canada*, June 2021, https://www.efficiencycanada.org/wp-content/uploads/2021/06/Retrofit-Mission-FINAL-2021-06-16.pdf.

B. Industrial Forecast

Forecasting industrial load is often challenging as it attempts to forecast the size and timing of future loads which can be lumpy and subject to uncertain timing. Anticipated industrial load growth may not materialize, and often does so in a large, binary manner. That is, a utility may expect 100 MW of new industrial load in 2030, which may be based on a new customer's plans to locate in the utility's service territory; if that customer later determines to locate someplace else (or to not invest at all), the outcome is that zero MW of those expected 100 MW materialize.

NLH has made a reasonable attempt to forecast industrial load for both the IIS and LIS using an approach that relies on soliciting, understanding, and vetting existing and potential new customer business activities and potential plans.[152] NLH builds its industrial forecast from the bottom up, looking at its existing large industrial customers individually and also assessing the potential new industrial customers that have expressed interest in siting loads in the province, particularly in Labrador. NLH has also appropriately focused on firm industrial demand for power, which is the portion of demand that a power supplier is obligated to provide, except during emergency conditions or other reliability events, and firm energy, which is the actual energy guaranteed to be available to meet customer requirements on an annual basis.[153] This may help reduce forecast error based on speculative customer plans or overestimated industrial activity.

For the IIS, NLH forecasts about 50 MW of peak load growth over the time horizon from its six existing industrial customers in the Slow Decarbonization and Reference Case scenarios. The Accelerated Decarbonization case forecasts growth of about 100 MW over the same period.[154] These growth estimates are based on the current industrial customers remaining in business in the province and at the levels of consumption forecasted by those customers.[155] All three cases also include new demand of 10 MW in 2028 due to "hydrogen developments."[156] These may be reasonable assumptions; however, we do note that in its most conservative case (the Slow Decarbonization case), NLH is forecasting about a 37 percent industrial peak load growth on the IIS by 2034, from about 160 MW to 220 MW.[157] There may be cause to explore a more conservative case which considers more tame decisions made by the six existing industrial IIS customers, or a spell of less favorable macroeconomic conditions. This conservative case may vary from the provided forecasts to show a downside of this more uncertain business segment (a scenario NLH has not accounted for in its Load Forecast Report). In the converse to this

152 Load Forecast Report, page 3 lines 3 to 5.

153 Load Forecast Report, page 3 n. 17.

154 Load Forecast Report, Chart 8.

155 Load Forecast Report, page 17 line 18 to page 18 line 4.

156 Load Forecast Report, page 17 lines 19 to 21.

157 Load Forecast Report, Chart 8.

recommended conservative case, we find no issue with the Accelerated Decarbonization case and believe it provides a reasonable look at the potential upper bound of industrial growth on the IIS in its provision of additional electrification and hydrogen developments.[158]

Overall, we think it was reasonable for NLH to explore both a reference case and high/low load cases to provide the Board and stakeholders with a view of potential future demand and energy scenarios. We understand these load forecasts may be used in a number of utility matters going forward. It is our view that in certain cases (such as the upcoming RRA proceeding), NLH supplement the IIS Slow Decarbonization case with a more granular look at future IIS industrial load. Doing so would allow NLH to better understand how, in a case that otherwise adopts the Slow Decarbonization assumptions, lower or flat industrial load growth would impact demand and energy forecasts. This would help ensure that any capital investment associated with future load growth would minimize risk of overbuilding the grid. We also note that NLH committed to "monitor closely and adjust future scenario assumptions as required" related to IIS industrial load growth going forward.[159]

The LIS forecasts, in our view, generally provide a reasonable assessment of future industrial load scenarios, subject to our discussion here. The LIS load forecast is (as we show above) highly dependent on the industrial load forecast, and LIS industrial load is as uncertain, and probably more so, than IIS industrial load. NLH has forecasted zero new customers and zero new industrial load growth through 2029 in all scenarios.[160] In the Reference case, NLH assumes flat industrial load through 2034.[161] This may be reasonable, but as with the IIS industrial forecast, the most conservative case does not consider the possibility that current industrial load could be negatively impacted by macroeconomic conditions or microeconomic forces affecting one or both of the two existing industrial customers. These are not idle concerns: we note that one of NLH's industrial customers on the LIS, Tacora Resources, which operates the Scully iron ore mine in Wabush in Labrador West, has been in creditor protection status since October 2023 and efforts to emerge were challenged in court.[162] It may be worthwhile for NLH to consider more conservative industrial load growth scenarios, particularly in any matters involving future capital investment.

NLH's Medium and High Growth cases, in our view, are reasonable approximations of future industrial load growth scenarios. NLH has appropriately focused on the Network Additions Policy ("NAP") for the LIS as the source for any new industrial load growth. Since

158 Load Forecast report, page 18 lines 1 to 9.

159 Load Forecast Report, page 18 lines 7 to 9.

160 Load Forecast Report, page 37, lines 2 to 7.

161 Load Forecast Report, Chart 20.

162 Elizabeth Whitten, "Global conglomerate raises objections to investment deal for Tacora-owned mine," *CBC*, February 23, 2024, https://www.cbc.ca/news/canada/newfoundland-labrador/tacora-cargill-objection-1.7120787.

these loads may not ultimately materialize, NLH has noted the need for monitoring of the NAP process and updates to its sensitivity forecasts.[163] We note, too, that subsequent to the Load Forecast Report, the other of NLH's LIS industrial customers (Iron Ore Company of Canada) received federal support for installation of an electric boiler at its iron ore processing operations in Labrador West.[164] This new load may be already accounted for in NLH's Medium and/or High Growth cases, but this should be clarified by NLH in future load forecasts or proceedings in which NLH's load forecasts are used.

Recommendation #6: *We recommend that NLH supplement the Slow Decarbonization case with an assessment of how lower or flat industrial load growth would impact demand and energy forecasts.*

C. Bates White's Conclusions and Recommendations

Based on our review of NLH's Load Forecast Report, Bates White concludes that the Company has considered relevant drivers of future peak demand and energy usage, and has generally applied industry standard forecast methods appropriately.

Our assessment of distinct components of the forecast, including econometric regression analyses, industrial load forecasting and projections of EV and electrification demand identified several areas where forecasting and reporting could be improved. Our recommendations presented in the sections above are repeated here:

Recommendation #1: *With respect to electricity prices, we recommend NLH reconcile and potentially update its load forecast to account for the Government's May 16, 2024 Muskrat Falls rate mitigation plan, which differs from the electricity prices modeled in the load forecast.*

Recommendation #2: *Given a) the importance of NLH load forecasting to the determination of future resource need; b) the changing drivers of energy demand reflected in the Load Forecast Report; c) the fact that the load forecast was conducted before 2023 actual data were available; and d) there is an ongoing study by a consultant for Hydro and Newfoundland Power to update the load potential study done by Dunsky in 2019, we recommend that NLH review its load forecasts and update them for significant changes identified in the review and/or by the consultant study.*

---

[163] Load Forecast Report, page 21 lines 5 to 7.

[164] Paul Moore, "Canadian government supports Rio Tinto's IOC decarbonisation to the tune of over C$18 million," *International Mining*, March 27, 2024, https://im-mining.com/2024/03/27/canadian-government-supports-rio-tintos-ioc-decarbonisation-to-the-tune-of-over-c18-million/.

Recommendation #3: *In its forecast update, NLH should assess the impact of flat population growth and the associated impact on customer count, consistent with low population growth scenarios evaluated by Statistics Canada.*

Recommendation #4: *NLH should detail the assumptions underpinning the EV scenarios it adopts, addressing the fact that projected penetration rates reflected in the load forecast fall short of Newfoundland and Labrador provincial targets, and the timing and extent to which growth in charging infrastructure will be achieved.*

Recommendation #5: *NLH should provide detail on key assumptions and their effects in its reporting, including details of oil-to-electric conversion programs made available to customers, the ability of customers to retain oil heating systems as backup, and the potential reliance on electric (i.e. resistive heating) backup to electric heat pumps.*

Recommendation #6: *We recommend that NLH supplement the Slow Decarbonization case with an assessment of how lower or flat industrial load growth would impact demand and energy forecasts.*

Attachment 2 – Bates White's List of Recommended Near-Term RAP Process Action Items

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.
(3)	5	III.B	Perform additional model runs with a 0.1 LOLE standard.
(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.
(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.
(16)	15	II.C.1	Clarify the specific expected timing of Holyrood's retirement relative to the commissioning of replacement generation.

Item Number	Page	Section	Recommendation
(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.
(21)	21	II.C.2	Assess projected cost and benefits of all investments made to improve LIL performance.
(22)	22	II.C.2	Continue to address all Haldar recommendations and update the RAP process with findings.
(23)	24	II.D	Continue review of ECDM options and structures, and clarify how NLH plans to incorporate learnings over time to inform potential future ECDM investments.
(24)	25	II.D	Address cost assumptions for BESS projects.
(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.
(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 NLH's initial queries to better assess the availability of such units.
(31)	27	II.D	Consider alternative fuel options for CT fuel source.
(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.

Item Number	Page	Section	Recommendation
(34)	28	II.D	Explain assumed timing of potential uprates and how such projects could affect the recommended portfolio.
(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.
(36)	28	II.D	Identify how the uprate of BDE7 is impacted by the inclusion of BDE8 in the Recommended Portfolio.
(37)	29	II.D	Consider 6- and 8-hour duration BESS projects.
(38)	29	II.D	Provide further support for the assumption of a five-year lead time for power transformers and circuit breakers.
(39)	30	II.D	Provide additional backup for ELCC figures utilized and consider the dynamic nature of ELCC calculations in the procurement process.
(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.
(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.
(43)	34	II.E	Further explore and justify the forced inclusion of wind resources in all sensitivity designs.
(44)	34	II.E	Further review and justify the annual fuel burn-off assumption which provides the need for sensitivity AC.
(45)	36	II.F	Consider incorporating firm energy analysis process into the PLEXOS model.
(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.

Item Number	Page	Section	Recommendation
(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.
(58)	43	II.G.1	Consider providing a LIL Shortfall Analysis assessment of a portfolio that included BESS.
(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 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 NLH will track and act on material changes in the supply and demand landscape that may affect the optimality of the recommended portfolio.