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December 9, 2025

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: *Reliability and Resource Adequacy Study Review* – Effective Load Carrying Capability Study

Please find enclosed Newfoundland and Labrador Hydro's Effective Load Carrying Capability Study, provided in accordance with the 2024 Resource Adequacy Plan Settlement Agreement.[1]

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc:

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Newfoundland Power Inc.
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Stephen F. Fitzgerald, KC, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
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[1] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 21, 2025, sch. 2.

Evaluating Effective Load Carrying Capability

Overview

December 9, 2025

A report to the Board of Commissioners of Public Utilities

Contents

List of Attachments

1.0 Context within the RRA Study Review

Newfoundland and Labrador Hydro ("Hydro") filed the initial Reliability and Resource Adequacy Study ("RRA Study") with the Board of Commissioners of Public Utilities ("Board") in November 2018 ("2018 Filing").[1] Since the 2018 Filing, throughout the continued *Reliability and Resource Adequacy Study Review* proceeding ("*RRA Study Review*"), Hydro has filed regular updates to the RRA Study, including numerous technical notes, additional studies, and third-party reports. The regulatory record for this proceeding is robust, with good reason. The provincial electrical grid is in the midst of unprecedented change—it is evolving from an isolated to an interconnected system, some of the assets the province has historically relied on most are aging and nearing retirement, there are significant new assets integrated into the electrical system and being proven reliable, and the province is facing an increase in demand driven by electrification.

Hydro's most recent study submitted to the Board on July 9, 2024, is its 2024 Resource Adequacy Plan,[2] containing Hydro's recommended Minimum Investment Required Expansion Plan. Subsequent to filing its 2024 Resource Adequacy Plan, Hydro and its experts participated in a series of technical conferences in the fall of 2024 with Board staff and intervening parties, along with their experts. These technical conferences provided an opportunity for fulsome discussion and enhanced understanding of Hydro's *RRA Study Review* and Expansion Plans. As a result of these proceedings, Hydro and the Intervenors gained consensus on a number of issues ("Settled Issues") which were enumerated in a Settlement Agreement.[3] The Settled Issues include agreement that the recommendation to build a new 150 MW unit at Bay d'Espoir (Unit 8) and a 150 MW Combustion Turbine ("CT") on the Avalon Peninsula ("Avalon CT") is appropriate as part of the first step in addressing the requirements for additional capacity for the Island Interconnected System, and applications for these projects should be filed for evaluation. In line with the Settled Issues, Hydro filed its 2025 Build Application for both of these assets in March 2025; the regulatory proceeding is ongoing.

[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).
[3] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine ("2025 Build Application")," Newfoundland and Labrador Hydro, March 21, 2025, sch. 2.

The *RRA Study Review* has included numerous rounds of requests for information and technical conferences, providing ample discourse and exchange of information between Hydro, the Board, and the parties.

In the coming years and decades, beginning with the recommended assets within its Minimum Investment Required portfolio, Hydro will have to make significant investments to maintain its legislative obligation of the provision of safe, least-cost, reliable electrical service in an environmentally responsible manner to the province.[4] As such, through the *RRA Study Review*, Hydro is modelling its system expansion in consideration of various forecast scenarios and within the context of continuously evolving energy policy. The numerous studies that Hydro has completed and planned are all necessary to validate and justify the information that Hydro inputs into its models, which produce critical information on which timely, prudent decisions are to be made.

While the enclosed study provides valuable, necessary information, it cannot and should not be considered independent of the rest of the studies and analyses ongoing through the *RRA Study Review*. Rather, the study is an input that will—along with other studies completed and ongoing—inform Hydro's broader system resource planning process now and into the future.

2.0 Background

The growing penetration of variable renewable resources, such as wind and solar, and energy-limited resources, such as battery storage in other jurisdictions, has highlighted the importance of capturing the interaction between variable, energy-limited, and other firm resources in the context of system planning. The Effective Load Carrying Capability ("ELCC") is a method for capacity accounting to meet resource adequacy. The ELCC Study, provided as Attachment 1, was performed by Energy and Environmental Economics, Inc. ("E3") to determine the ELCC values for wind, solar, and battery storage, as it applies to the Island Interconnected System. These values, along with a characterization of the system's future resource adequacy needs, are important inputs into the resource planning process.

The ELCC is derived from loss-of-load probability modeling by translating system performance under a wide range of load, weather, and hydro conditions into resource-specific adequacy values. These values are dynamic and can change as resource penetration increases and as the mix of resources on the Island

[4] *Electrical Power Control Act*, 1994, SNL 1994, c E-5.1, s 3(b)(iii).

Interconnected System changes. By using an ELCC-based methodology for wind, solar, and battery storage, Hydro can more accurately assess future reliability risk and resource contributions to meet the Island's reliability requirements.

The ELCC Study used E3's Renewable Energy Capacity Planning Model ("RECAP")[5] to conduct Loss of Load Probability modelling and calculate ELCC values for all resources, including existing, planned, and future resource options, to quantify their contribution towards resource adequacy for the Island Interconnected System. The study focuses primarily on the Island Interconnected System in the reference year of 2032, as it is expected that the retirement of aging thermal assets will have occurred prior to this year.

The purpose of this overview is to provide a high-level summary of E3's findings and recommendations, as well as Hydro's planned next steps.

3.0 ELCC Study Results

3.1 Solar

Solar resources were found to contribute very little to system adequacy. As shown in Table 1, a representative 20 MW solar project provides 2.2 MW of firm capacity.

Table 1: Generic Solar ELCC

Resource	Nameplate Addition (MW)	Cumulative Capacity Value (MW)	Marginal ELCC[6] (%)
Generic Solar	20	2.2	11

The modest contribution of solar is not unexpected due to the low solar capacity factor of 14% on the Island and the misalignment between midday solar output and early morning or evening winter peaking period. For the Island Interconnected System, solar has a limited role in supporting reliability requirements.

[5] RECAP is a loss-of-load probability model developed by E3 that is used to assess the reliability of electricity system portfolios. The model is designed to evaluate the resource adequacy of electrical power systems, including systems with high penetrations of renewable energy and other resource dispatch-limits such as hydropower, energy storage, and demand response.
[6] Marginal ELCC rate is slightly lower than the cumulative ELCC rate as the effectiveness of the Battery Energy Storage System decreases with each installation.

3.2 Wind

Wind resources were found to contribute substantially higher resource adequacy contributions, as wind generation can more often overlap with morning and/or evening peak demands. As shown in Table 2, a representative 50 MW wind project provides 22 MW of firm capacity.

Table 2: Generic Wind ELCC

Resource	Nameplate Addition (MW)	Cumulative Capacity Value (MW)	Marginal ELCC[6] (%)
Generic Wind	50	22	43

It is important to note that as wind penetration increases, the marginal ELCC steadily declines, which is depicted in Figure 1.

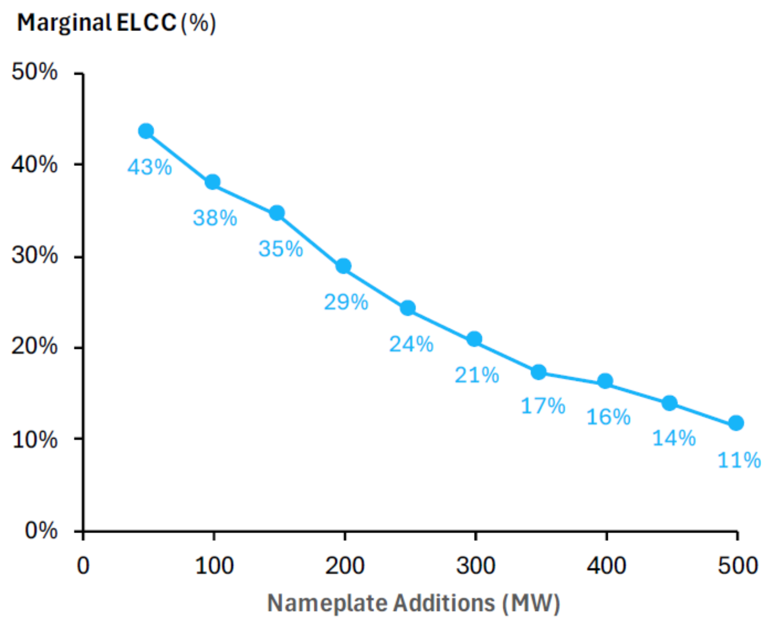

Figure 1: Wind Marginal ELCC

As wind penetration increases to 100 MW, the marginal ELCC decreases from 43% to 38%. This pattern continues as wind penetration increases, resulting in a marginal ELCC of only 11% after 500 MW of wind is added to the Island Interconnected System. The decline is attributed to how, even with a degree of geographic diversity, additional turbines can experience similar wind patterns. On this basis, a larger wind fleet could be simultaneously exposed to a low-wind event during a period of high demand. The result is a diminishing capacity benefit as more turbines are added.

3.3 Storage Resources

The ELCC Study focused on the incremental capacity value of battery storage for 4-hour and 8-hour durations. As shown in Table 3, a representative 4-hour 50 MW battery storage project provides approximately 20 MW of firm capacity; whereas an 8-hour 50 MW battery storage project provides approximately 27 MW of firm capacity.

Table 3: Generic Battery ELCC

Resource	Nameplate Addition (MW)	Cumulative Capacity Value (MW)	Marginal ELCC[6] (%)
4-hr Battery Storage	25	11	43
4-hr Battery Storage	50	20	37
8-hr Battery Storage	25	15	59
8-hr Battery Storage	50	27	50

Similar to wind penetration, as the penetration of battery storage increases, the marginal ELCC declines for both 4-hour and 8-hour options, which is depicted in Figure 2.

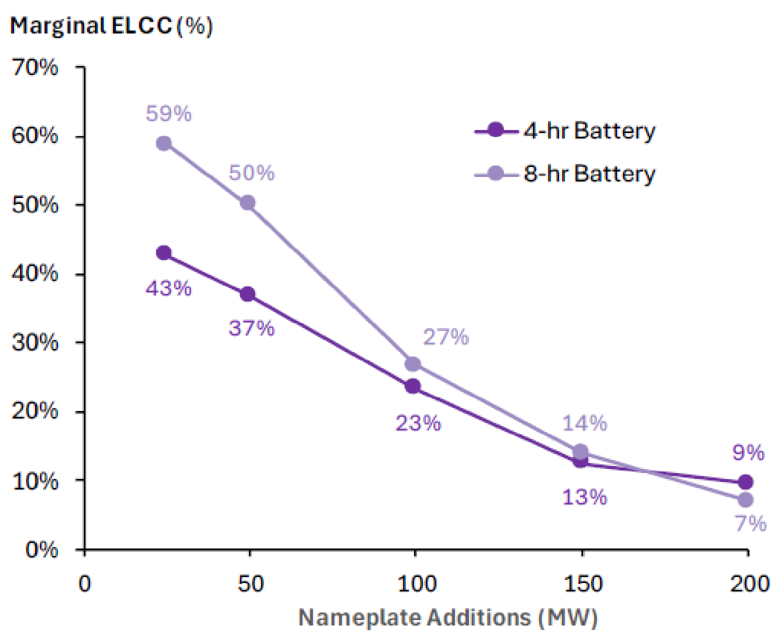

Figure 2: Battery Storage Marginal ELCC

Highlighting the 4-hour storage option, as battery penetration increases from 50 MW to 100 MW, the marginal ELCC substantially declines from 37% to 23%. This pattern continues as battery penetration increases, resulting in a marginal ELCC of only 9% after 200 MW of 4-hour battery storage has been added to the Island Interconnected System.

The 8-hour storage options perform better than 4-hour storage options at low penetrations, with the marginal ELCC increasing from 37% to 50% at 50 MW penetration. This is due to the longer duration of storage, enabling the storage to cover more of the system's higher-risk hours (i.e., peak periods), allowing the battery to more effectively support system reliability. The increase in the marginal ELCC of 8-hour storage over 4-hour storage decreases significantly as penetration increases, and there is no significant benefit once penetration reaches 150 MW.

3.4 Complementary Interactions Between Wind and Storage

The combined capacity value of an entire portfolio is interdependent, as changes to the penetration of one resource affect the capacity value of other resources. Therefore, the ELCC Study calculated the incremental ELCCs for different combinations of wind and battery storage resources to determine the potential interaction effects between these two resources. The results showed a small complementary interaction when combining the two resources. This is shown in Table 4 which includes the cumulative incremental ELCC resulting from each combination of wind and storage option. As the penetration of either resource increases, the total capacity contribution of the incremental resources also increases, reflecting their additional reliability contribution to the Island Interconnected System.

Table 4: Cumulative ELCC (MW) from Combinations of Incremental Wind and Storage Resources

Incremental Wind Capacity (MW)	Incremental 4-hour Storage Capacity (MW)					
	0	25	50	100	150	200
0	-	11	20	32	38	43
50	22	33	42	53	60	64
100	41	53	62	73	80	84
150	58	70	79	92	99	104
200	72	85	95	109	118	123
250	84	98	109	125	135	141
300	95	109	121	138	150	157
350	103	117	130	150	164	172
400	111	126	138	159	175	186
500	124	139	152	173	191	206

The quantity of the benefit can be calculated from the table above by comparing how much additional effective capacity is provided by each increment of installed capacity within each step.[7]

As an example, if 200 MW of wind capacity and 50 MW of storage capacity were added to the system, the resultant ELCC would be 95 MW. However, 200 MW of wind generation on its own would have an ELCC of 72 MW and 50 MW of storage on its own would have an ELCC of 20 MW, for a total of 92 MW. This implies that there is a 3 MW reliability benefit that can be attributed to the complementary interactions between the two technologies, in this example.

4.0 Comparison to the 2024 Resource Adequacy Plan

4.1 Wind

The calculated ELCC for wind resources as determined by E3 differs from the ELCC value for wind that was used in Hydro's 2024 Resource Adequacy Plan and the 2025 Build Application, which assumed 22% ELCC for wind resources.[8] There are a number of key distinctions between the two studies that result in this difference:

- **Different Models:** E3 uses RECAP, and the prior study used Hydro's own reliability model in PLEXOS. The main difference between the two is the sampling for wind profiles—the former preserves the correlation between load condition and wind generation, while the latter draws profiles randomly.
- **Different Test Year:** The prior study measured ELCCs for two existing wind farms in 2024. This study explores incremental ELCCs for similar wind turbines in a nearby location and assumes they are operated in 2032. The disparity in study year alone makes this current study not directly comparable due to shifts in loads and resources.
- **Increased Weather Variability:** The prior study uses one hourly load profile for a base weather year, whereas this study uses eight weather years. This increase in weather years ensures a more complete representation of weather-dependent wind performance during challenging periods.

[7] For further information, please refer to "Newfoundland & Labrador Hydro ELCC Study – Evaluating Effective Load Carrying Capability," Energy+Environmental Economics, November 2025, p. 34, Tables 9 and 10.
[8] This analysis was initially completed in the "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, re. September 6, 2019 (originally filed November 16, 2018), vol.I, att.6, and expanded upon in the "2019 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, att. 1.

- **Labrador-Island Link ("LIL") Forced Outage Rate ("FOR"):** The prior study used a LIL bipole FOR of 0.0114% (equivalent to 1 hour per year), whereas this study uses a EqFOR[9] of 5%. This has significant implications on the outage profile in the model (specifically, timing of the most resource needs) and the ELCC results.[10]
- **Increased Stochasticity:** In addition to the increased weather variability, this study captures a wider range of plausible load, hydro, and wind combinations by explicitly mapping hydro availability to load and resource performance across the full set of simulated scenarios.

While all of these factors result in a higher incremental ELCC for wind in this study, the largest contributing factor for generation requirements on the Island Interconnected System is due to the retirement of Holyrood Thermal Generating Station ("Holyrood TGS") and the increased reliance on the LIL. By the year 2032, the most loss-of-load risk occurs during the winter period, coinciding with LIL outages.

The reduction in wind ELCC contribution does not impact the capacity resource options identified in the recommended Minimum Investment Required Expansion Plan. The first large capacity resource option (Bay d'Espoir Unit 8) is required in 2031 to meet the planning reserve margin requirements, and the second large capacity resource option (Avalon CT) is advanced to 2031 to mitigate the loss of load associated with a potential LIL shortfall event. The LIL shortfall analysis is not impacted by changes to ELCC contribution.

4.2 Storage Resources

The 2024 Resource Adequacy Plan included expansion plan sensitivities with 4-hour duration batteries with an assumed battery ELCC of 40%, 60%, and 80% to capture a potential ELCC range.[11] The Expansion Model selected batteries for capacity when assigned an ELCC of 60% to 80%; however, under the Reference Case and Slow Decarbonization load forecasts, the model did not select batteries when the ELCC applied was 40%. Therefore, there is no impact on the recommended Minimum Investment Required Expansion Plan.

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[9] Equivalent Forced Outage Rate ("EqFOR").

[10] E3 simulated LIL EqFORs of 1% and 3% as sensitivities to this analysis, and there was no discernible difference compared to a LIL EqFOR of 5% in the calculation of ELCCs.

[11] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally field July 9, 2024), app. C.

5.0 Conclusion and Next Steps

The ELCC Study provided observations and calculated ELCC values for solar, wind, storage, and a combination of wind and storage, which will help Hydro's long-term resource planning process. The key findings include:

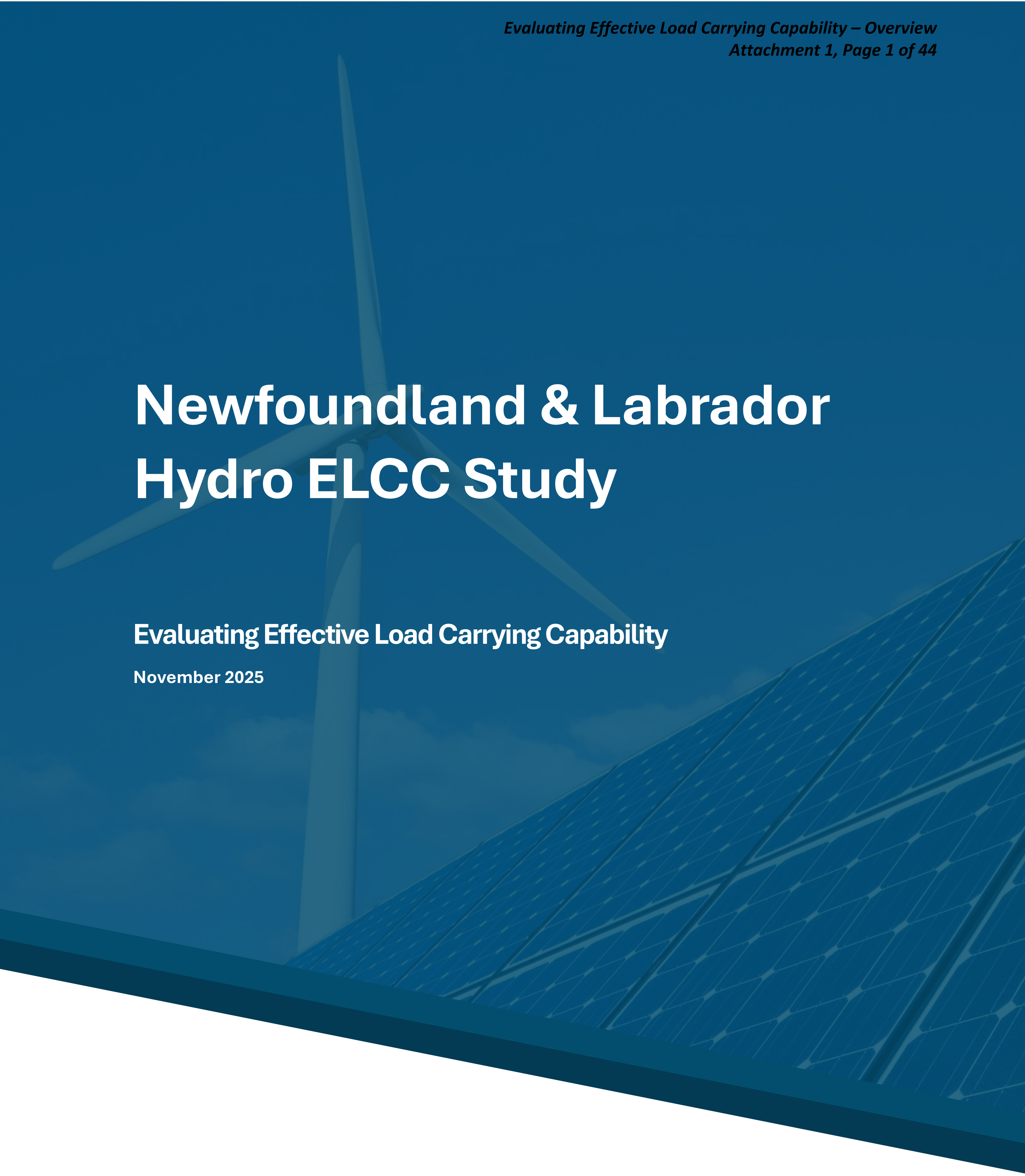
- **As the Island Interconnected System enters a period of major grid transformation, the periods of greatest reliability risk are expected in cold winter, early mornings and evenings.** E3 modelled grid resource adequacy in 2032, a time characterized by retiring assets, new resource additions, and rising electricity demand. The planned retirement of the Holyrood TGS in 2030 will create the need to develop new sources of energy and capacity. The periods of highest risk in the Hydro system are expected to be early winter mornings and evenings, during the times of the highest winter heating loads.
- **Wind generation produces significant reliability benefits for the system.** The high availability of wind generation during the winter peak period aligns well with the periods of greatest reliability risk. As a result, the marginal ELCC for wind begins in the mid-40% and declines with increasing penetration as reliability risks shift towards periods of lower wind output.
- **Solar Generation does not provide significant reliability benefits to the system.** In contrast to wind, given the poor alignment between peak solar generation (in the midday in the spring and summer) and highest system risk (early morning and evenings in the winter), the ELCC value for solar is lower, at approximately 11%.
- **Energy storage provides significant reliability benefits to the system at low penetration, but this declines quickly as penetration increases.** Hydro has significant generation from flexible hydro and significant demand response contracts, both of which have antagonistic effects when combined with storage. As a result, the incremental capacity value provided by storage is meaningfully lower than its full nameplate value (i.e., about 43% after the first 25 MW of 4-hour storage and 59% after the first 25 MW of 8-hour storage). These results are lower than those typically seen in thermal-dominated systems. At higher levels of storage deployment, as reliability risks extend over longer durations, the marginal ELCC values decline significantly as penetration increases.

The values and results developed in the ELCC Study are intended to inform Hydro's planning process and the next Resource Adequacy Plan.

Attachment 1

Newfoundland & Labrador Hydro ELCC Study: Evaluating Effective Load Carrying Capability

Energy and Environmental Economics, Inc.



Newfoundland & Labrador Hydro ELCC Study

Evaluating Effective Load Carrying Capability

November 2025

Energy+Environmental Economics

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Acronym Definitions

Acronym	Definition
RA	Resource Adequacy
CAISO	California Independent System Operator
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
EV	Electric Vehicle
ICAP	Installed Capacity
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PLEXOS	A Commercial Energy Systems Modeling Software
PRM	Planning Reserve Margin
RECAP	An Energy Systems Modeling Software for LOLP Modeling
RRA	Reliability and Resource Adequacy Study
UCAP	Unforced Capacity

Executive Summary

Newfoundland and Labrador's electricity system is in a period of major transition, marked by new transmission, evolving generation resources, and ongoing efforts to reduce reliance on aging thermal generation. Over the coming decade, the region also anticipates load growth, driven by new industrial developments and the electrification of transportation, heating, and other end uses. At the same time, Newfoundland and Labrador Hydro (NL Hydro) is preparing for the retirement of key thermal assets and the need to integrate new sources of clean energy and capacity to maintain reliability.

In this context, NL Hydro engaged E3 to estimate the effective load carrying capability (ELCC) of prospective resources on the provincial grid. These ELCC results provide critical inputs to NL Hydro's long-term planning process, supporting the identification of a least-cost, reliable portfolio of resources. This study builds on the modeling completed for NL Hydro's 2024 Resource Adequacy Plan and will inform subsequent planning and procurement efforts, including the utility's Energy and Capacity Expression of Interest (EOI) and future Request for Proposal (RFP) processes.

Key Questions

This study assesses the ELCC values of the NL Hydro system using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including in California, Atlantic Canada, the Pacific Northwest, the Upper Midwest, Texas, New York, and Florida. RECAP is designed to address the needs of a changing electricity sector by incorporating the unique characteristics of dispatch-limited resources such as wind, solar, hydro, battery storage, and demand response into the traditional reliability framework.

Specifically, this study analyzed two key questions:

1. What are the periods of greatest reliability risk on the Island Interconnected System in 2032?
2. How effective are different resources—including wind, solar, and storage—in meeting this reliability need in 2032?

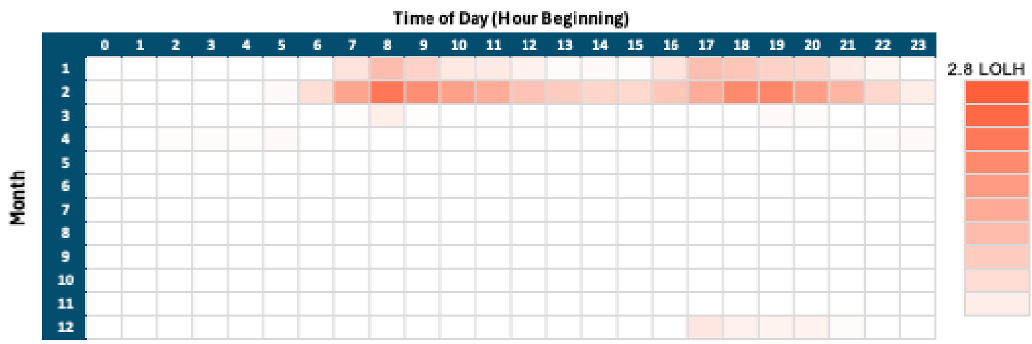
Key Findings

The report generated the following key findings related to the NL Hydro system.

1. **As Newfoundland and Labrador enter a period of major grid transformation, the periods of greatest reliability risk are expected in cold winter early mornings and evenings.** E3 modeled grid resource adequacy in 2032, a time characterized by retiring assets, new resource additions, and rising electricity demand. The planned retirement of the Holyrood Thermal Generating Station, the province's largest thermal plant, around 2030 will create the need to

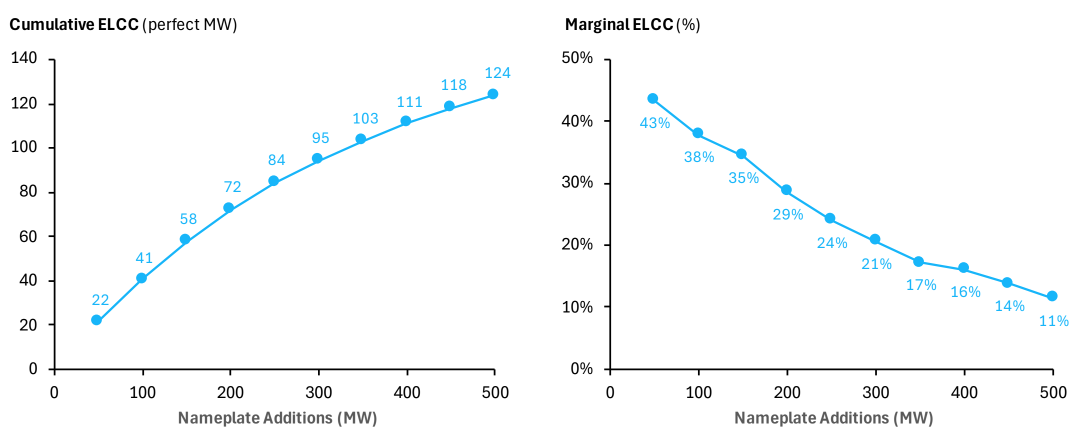
develop new sources of energy and capacity. At the same time, shifts in consumer behavior, industrial growth, and evolving climate policies are expected to accelerate electricity demand, emphasizing the need for careful planning to maintain reliability. As shown in the chart below, the periods of highest risk in the NL Hydro system are expected to be early winter mornings and evenings, during the times of the highest winter heating loads.

ES Figure 1. Relative Loss of Load Probability in 2032 by Month and Hour of the Day



2. **Given the winter-peaking system, wind generation can play an important role in meeting Newfoundland & Labrador's resource needs.** Given high availability during the winter net peak period, the marginal ELCC for wind begins in the mid-40% and declines with increasing penetration as reliability risks shift towards periods of lower wind output. In contrast, given the poor alignment between peak solar generation (in the midday) and highest system risk (early morning and evenings), the ELCC value for solar is lower (about 11%).

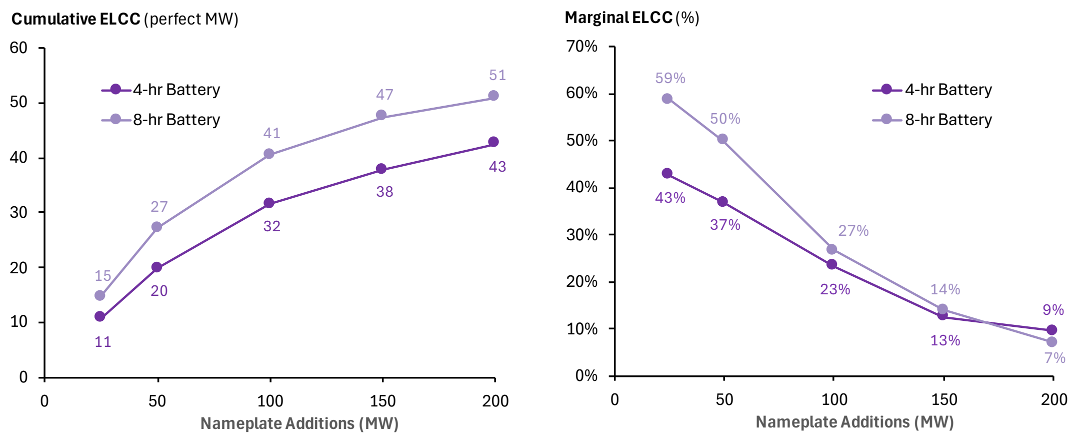
ES Figure 2. Cumulative and Marginal ELCCs for Wind Resources, on top of 2032 Existing and Planned Resource Portfolio



3. **Energy storage may also play a role in meeting NL Hydro's resource adequacy needs, reflected in ELCC values from 40-60% in initial tranches.** New energy storage can charge from surplus hydro generation and discharge during peak periods. However, due to the flexibility of existing hydro generation as well as the province's extensive demand response

programs, the incremental capacity value provided by storage is meaningfully lower than its full nameplate value, i.e., about 43% for the first 25 MW of 4-hour storage and 59% for the first 25 MW of 8-hour storage. At higher levels of storage deployment, as reliability risks extend over longer durations, the marginal ELCC values decline further. These results are lower than in thermal-dominated systems, reflecting the storage capability already provided by Newfoundland and Labrador's flexible hydro resources and the 130+ MW of demand response already in the portfolio.

ES Figure 3. Cumulative and Marginal ELCCs for Storage Resources, on top of 2032 Existing and Planned Resource Portfolio



4. **The Labrador–Island Link (LIL), a 700 MW high voltage transmission asset from Muskrat Falls, provides a key source of capacity and reliability to the NL Hydro Island system.** Commissioned in April 2023, this asset is relatively new but represents the single largest source of energy to the island. From a reliability perspective, the modeling considered the physical system limits and operational uncertainties of this major transmission line, particularly during the coldest winter months when the system is more constrained. The Labrador Island Link (LIL) delivers large volumes of hydroelectric energy from Muskrat Falls to the island but like any asset, incurs some reliability risk due to its operational uncertainty. A hypothetical outage on this single transmission link could create system-wide adequacy challenges, particularly during winter peaks. This dependence on a single asset influences the types of resources that can provide complementary contributions to the Island's reliability needs.

The values and results developed in this study are intended to inform NL Hydro's planning process for the next Reliability and Resource Adequacy study. At the same time, this study is subject to limitations, many of which are associated with limited operational experiences with newer assets, including both the LIL and new renewable generation. As the system evolves, it will be important to proactively evaluate emerging risks and determine whether updates to the analysis are necessary to address specific challenges. Given limited operational experience with both the LIL and new renewable generation, it will be important to monitor and collect data on these resources to obtain increasingly robust assessments of their performance under a range of system conditions.

1. Introduction

1.1 Background & Context

NL Hydro engaged E3 to support a study estimating the effective load carrying capability (ELCC) of potential candidate resources on the Newfoundland and Labrador grid. These values, along with a characterization of the system's future resource adequacy needs, are critical inputs to the planning process, which enables the utility to identify a least-cost, reliable portfolio of resources. Like utilities across North America, NL Hydro is anticipating meaningful load growth in the coming decade, driven both by new industrial projects and by electrification of end uses such as transportation and residential heating. At the same time, NL Hydro is expecting to reduce its reliance on aging thermal generation. To meet growing demand while continuing to deliver reliable electricity to customers, new resource additions are likely to be required. This study builds on the modeling work conducted in NL Hydro's 2024 Resource Adequacy Plan. These findings supplement that work and provide input to NL Hydro's Energy and Capacity Expression of Interest (EOI) and expected subsequent Request for Proposal (RFP) process to inform future procurement.

Leveraging industry best practices for resource adequacy modeling, including reliance on loss of load probability (LOLP) modeling, this study first identifies periods of highest reliability risk for the NL Hydro Island grid at a system loss of load expectation (LOLH) target of 2.8 hours per year. It then evaluates how much accredited capacity a range of variable and energy-limited resources can contribute to that requirement using an ELCC methodology. ELCC modeling requires simulation across hundreds of combinations of system conditions, allowing for the identification of periods of greatest reliability risk due to adverse weather, hydrological constraints, or transmission outages, and thereby enabling an accurate characterization of the capacity value of different resources.

1.1.1 Key Reliability Considerations for Newfoundland and Labrador

Over the coming decade, the NL Hydro system will undergo transformations driven by the evolution of both supply and demand changes. On the supply side, Holyrood Thermal Generating Station (Holyrood TGS), the largest thermal plant in the province, is planned to retire around 2030 and be replaced by new sources of energy and capacity. Concurrently, changing consumer behavior, industrial developments, as well as evolving climate change policies, have all accelerated demand for electricity, leading to heightened reliance on the system's grid infrastructure. The Newfoundland Island system also faces unique reliability challenges due to its reliance on a single major transmission line, the Labrador Island Link, that delivers hydroelectric generation from Labrador.

Ensuring ongoing resource adequacy in this dynamic period will be essential to supporting customers. This study evaluates system reliability metrics on the Island grid of the NL Hydro system for the year 2032, reflecting the recently proposed and expected capacity resource additions and planned retirements. Throughout the assessment, several key dynamics and features of the NL Hydro system and reliability challenges guide the analysis, including:

- **Thermal retirement:** Retirement of major thermal resources such as the Holyrood Thermal Generating Station reduces the amount of firm capacity on the grid. This plant has historically played a key role in meeting peak demands and supplying winter baseload energy, and its retirement will leave a gap to be addressed by new energy and capacity resources.
- **Uncertain load growth:** Increasing rates of electric vehicle adoption coupled with new industrial projects (e.g., mining loads) could introduce step changes in demand that are both large and uncertain, complicating the timing and scale of resource needs.
- **Increasing reliance on transmission:** The Labrador Island Link (LIL) delivers large volumes of hydroelectric energy from Muskrat Falls to the island but also introduces reliability risks due to its operational uncertainty. Outages on this single transmission link can quickly create system-wide adequacy challenges, particularly during winter peaks. This dependence on a single asset has impact on what type of resource can contribute the most to reliability needs.
- **Integration of renewables and storage:** New wind, solar, and battery portfolios are expected to play a larger role in meeting future needs. Their contribution to adequacy depends on both penetration levels and the timing of their output relative to system risk periods. In a hydro-dominated system, their interactions with reservoir operations may complicate their dependable capacity rating[1].
- **Extreme weather impact:** As a winter-peaking system, NL Hydro must plan for periods of cold temperatures that can simultaneously extend peak demand periods for heating and reduce renewable output, particularly wind. These multi-day events can stress system resources beyond typical peak hours, requiring resources that can ramp up and dispatch for long periods.

In this context, ELCC provides a natural extension of traditional reliability planning tools. Derived from loss-of-load probability modeling, ELCC translates system performance under a wide range of load, weather, and hydro conditions into resource-specific adequacy values. These values are dynamic: they change as resource penetrations increase and as the mix of system resources evolves. For NL Hydro, adopting an ELCC-based methodology offers a more accurate and flexible foundation for assessing future reliability risks and resource contributions.

Ultimately, this study will give NL Hydro a clearer picture of how different resources can contribute to system adequacy. These insights will inform both near-term procurement decisions and longer-term resource planning, ensuring NL Hydro is well-positioned to meet future load reliably and cost-effectively.

1.1.2 Report Overview

The remainder of this report is organized into the following sections:

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[1] The process of assigning a resource's ELCC value or dependable capacity can also be referred to as "capacity accreditation".

- **Section 2 (Modeling Approach)**: Provide an overview of the RECAP model and describes how it was customized to reflect the specific conditions of the NL Hydro system.
- **Section 3 (Modeling Inputs and Assumptions):** Document the key inputs and assumptions used in the RECAP loss-of-load-probability modeling.
- **Section 4 (Modeling Results and Discussion):** Focuses on the year 2032, presenting the reliability challenges NL Hydro may face and the ELCC analysis results for different resource types, indicating their potential reliability contributions to the island grid.

1.2 Resource Adequacy Overview

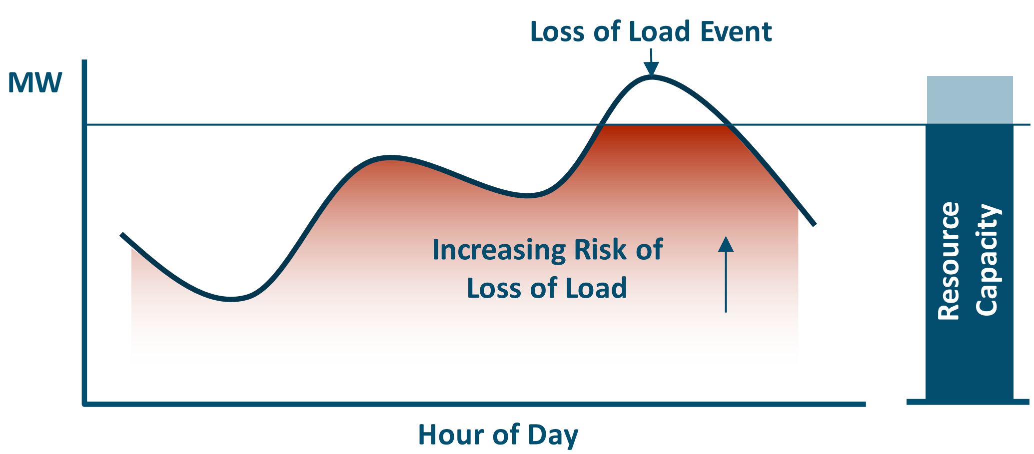
1.2.1 Defining Resource Adequacy

"Resource adequacy"[2] is the ability of an electric power system to provide sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other factors that may limit their availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers. The chart below illustrates a type of loss-of-load event driven by high load demand where resource capacity is insufficient to serve load.

NERC Definition of Resource Adequacy

"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Figure 1. Illustration of a Loss of Load Event Due to Insufficient Generation

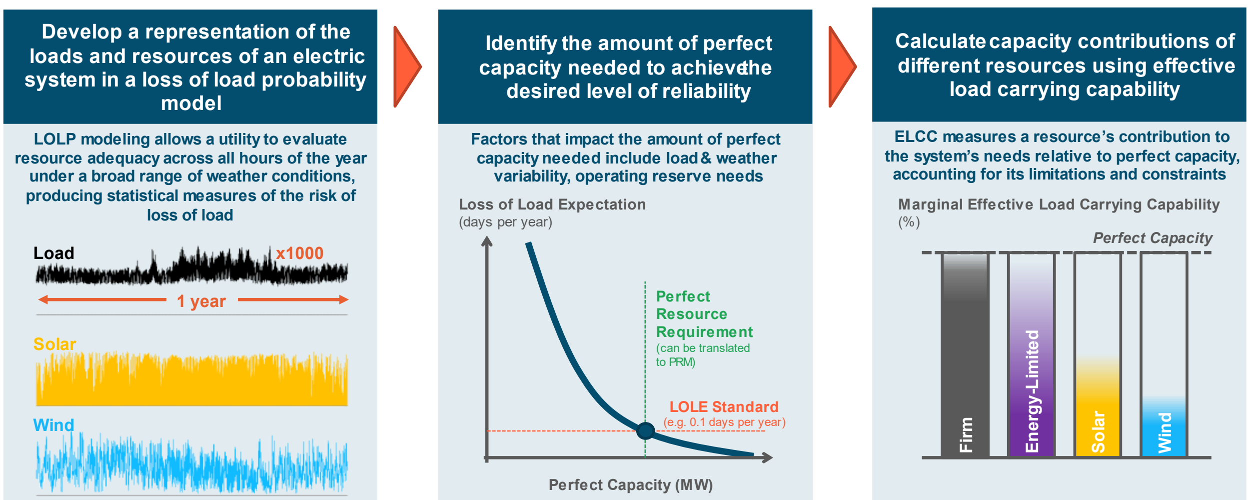


[2] https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

1.2.2 Introduction to RA Best Practice Framework

The growing penetration of variable renewable resources (whose output is constrained by intermittency) and energy-limited resources (whose production is constrained by duration) is challenging the traditional planning reserve margin approach long used to ensure resource adequacy, underscoring the need to design the system to perform under the most constrained operating conditions. With improved understanding of these challenges and innovations in probabilistic methods designed to capture the interaction between variable and energy-limited resources, utilities and program administrators have begun modernizing their resource adequacy planning practices (see Figure 2 below)[3].

Figure 2. Three Foundational Pillars Underpinning a Robust Approach to Resource Adequacy



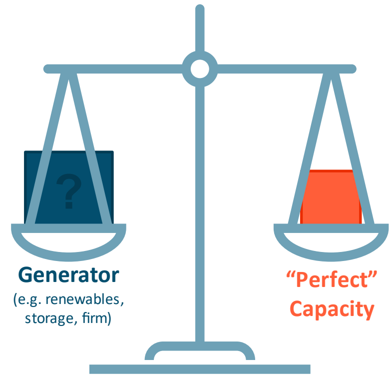
The robust framework for resource adequacy requires three components:

1. Development of a **loss-of-load-probability (LOLP) model** that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather conditions to identify periods in which an electricity system is vulnerable to reliability risks;
2. Derivation of a **total capacity requirement** that reflects the amount of "perfect capacity" needed to achieve an acceptable standard of reliability; and
3. Application of an **effective load carrying capability (ELCC)** accounting framework to measure the contribution of each resource (or portfolio of resources) towards the total capacity requirement. Under a critical period framework, ELCC will be determined on a marginal basis (marginal ELCC), which can also be understood as representing its expected performance during critical periods. The use of marginal accreditation is important to

[3] More detail on these challenges, and on a framework that formalizes and advances emerging methods for evaluating resource adequacy needs, is provided in E3's white paper, Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets: https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf

ensure efficient capital investment by accurately capturing the marginal value of additional resource investments.

Figure 3. Effective Load Carrying Capability (ELCC) as a Measure for Resource Accreditation



A resource's ELCC is a measurement of the amount of perfect capacity that providesan equivalent reliability benefit to the system

Within this framework, the capacity value assigned to each resource (or portfolio of resources) is determined using an ELCC methodology, which relies on the same LOLP modeling techniques to determine the amount of perfect capacity that provides an equivalent value to system reliability. Properly applied, an ELCC-based framework for capacity accreditation naturally accounts for the oft-cited complications that arise as high levels of renewables are integrated, including the "shift to the net peak," the need to account for energy sufficiency as well as capacity, and the saturation effects and diversity benefits that accrue to portfolios of variable and energy-limited resources. ELCC is therefore broadly viewed as the cornerstone of a robust approach to capacity accreditation and has quickly gained widespread usage within the industry.

The ELCC method has emerged as the preferred metric for capacity accounting to meet resource adequacy for multiple reasons:

- **ELCC is determined directly from the LOLP analysis utilized to calculate the planning reserve margin (PRM) requirement, reflecting a resource's contribution to a specified statistical standard.**

As a derivative of the LOLP modeling used to calculate need, ELCC captures a resource's performance across a wide range of system conditions. This ensures that the estimation of capacity contributions is robust across a wide distribution of potential outcomes, including infrequent tail events (e.g., higher load and lower renewable output than expected) that are the primary drivers of reliability challenges.

- **ELCC provides a technology-agnostic framework for the measurement of resources' reliability contributions, offering an economically efficient signal for new resource investment.**

This approach therefore puts all resources on a level playing field and ensures equitable treatment among them as well as accurate measurement of their contributions to reliability at the margin. A resource with an ELCC of 1 MW has the same contribution toward resource adequacy, regardless of whether that capacity contribution comes from solar PV, wind, energy storage, natural gas, or coal.

- **ELCC directly accounts for complex interactive effects between different resources in the portfolio, including saturation effects that occur when the penetration of a single resource increases and the diversity benefit attendant to complementary resources.**

ELCC naturally accounts for both the saturation effects that occur as one type of resource is added to the system in increasing quantities and the interactive effects between different types of technologies to provide a comprehensive, accurate measurement of the contribution of dispatch-limited resources to the system. These dynamics are crucial to consider in planning a reliable system that relies heavily on renewable and storage resources.

In practice, the same qualities that make ELCC the most robust method for measuring capacity contribution also make it a complex method to apply. The simplest example of an application of ELCC is in the context of a vertically integrated utility that is responsible for meeting its own resource adequacy requirement with a single portfolio of resources. For such a utility, accrediting capacity value to individual resources is not strictly necessary—what matters is whether the utility's total portfolio meets its total needs. In this case, the application of ELCC may reasonably rely directly on the two "measurable" ELCC values: portfolio and marginal. Both are directly useful to the utility:

- To assess whether a given combination of resources is sufficient to meet a utility's resource needs, the **portfolio (or cumulative) ELCC** provides a measure of the combined capacity contribution of all resources in its portfolio.
- To evaluate potential resource additions, the **marginal ELCC** for each resource provides a measure of how much that resource will increase the total ELCC of the utility's portfolio, offering a means of comparing the relative capacity value of resource alternatives to identify the least-cost resource among a discrete set of options.

Together, these two constructs can allow a utility to simultaneously ensure the reliability of its existing portfolio of resources and make economically efficient decisions in the procurement of new capacity resources to meet incremental need.

2. Modeling Approach

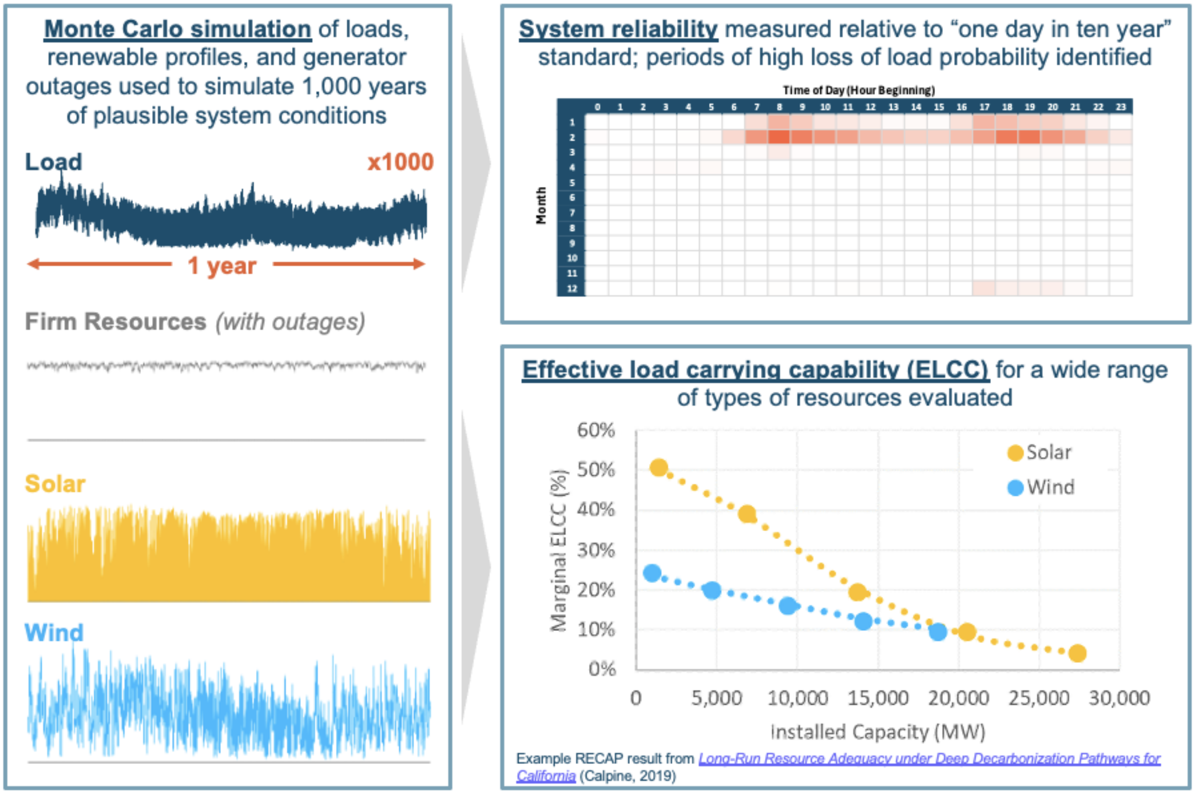
This study uses E3's **Renewable Energy Capacity Planning (RECAP)** model to conduct LOLP modeling and calculate ELCC values for potential future resources, which quantifies their contribution towards Resource Adequacy requirements in the Interconnected System (Island). The study focuses primarily on the NL Hydro system in 2032, as it is expected that all retirements of thermal assets will occur prior to this date.

2.1 RECAP Overview

RECAP is a loss-of-load-probability model developed by E3 that is used to assess the reliability of electricity system portfolios, and has been used extensively across North America, including in California, Hawaii, Atlantic Canada, New York, the Pacific Northwest, the Desert Southwest, the Upper Midwest, Florida, and many other jurisdictions. The model is designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response.

RECAP evaluates resource adequacy through time-sequential simulations of hundreds of years of plausible system conditions to calculate a statistically significant measure of several important system reliability metrics, like the planning reserve margin required to achieve a target loss-of-load standard, and individual resource contributions to system reliability, measured through their effective load carrying capability. RECAP also includes stochastic forced outages of thermal plants and time-sequentially tracks demand response and storage state of charge. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP calculates these metrics by simulating electricity system resource availability with a specific set of generating resources and loads under a wide variety of weather-years, renewable generation-years, and stochastic forced outages of generation resources. By simulating the system thousands of times through Monte Carlo analysis with different combinations of these factors, RECAP provides a statistically significant estimation of loss of load expectation (LOLE, LOLH, or EUE). An overview of the RECAP model is shown in Figure 4.

Figure 4. Overview of RECAP Model



2.1.1 RECAP Model Inputs

In order to perform each step in the model described above, RECAP requires data on the characteristics of loads and the resources available to serve those loads. These are listed in Table 1. The primary focus of this study is the Island Interconnected System. A more detailed description of how the data is customized and used in NL Hydro's RECAP modeling is described in Section 2.2.

Table 1. RECAP Data Requirements

Category	Metric	
Load	Historical hourly load for multiple weather years	
	Operating reserve requirements	
Dispatchable Generation	Installed capacity	
	Forced outage rate (FOR)	Mean time to failure (MTTF)
		Mean time to repair (MTTR)
	Maintenance schedules	
Renewable Generation	Nameplate capacity	
	Historical hourly generation profiles for many weather years	

Hydro Generation (Large Reservoir Hydro)	Monthly MWh budget availability from many hydro years
	Maximum output & sustained peaking limits
Hydro Generation (Small Run-of-River Hydro)	Simulated generation profile for many hydro years
	Maximum output
Demand Response	Maximum capacity
	Maximum # of calls per week/month/year
	Maximum duration of each call
LIL Imports	Energy Absorption Limit based on hourly loads and ML flow
	Generation Profile at Muskrat Falls
	Forced outage rate (FOR)
Other Transmission	Maritime Link export to NS

2.1.2 RECAP Model Outputs

After all resources have been dispatched in the model for load plus operating reserves, the model aggregates that remaining loss of load events to calculate various reliability statistics for the system including LOLE, LOLH, LOLEV, and EUE. The model then assesses whether the achieved reliability of the system for a specific metric (for example, LOLH) is greater or less than the target metric (for example, 2.8 LOLH) and then uses an iterative tuning process to add or remove firm capacity from the system in order to achieve the target level of reliability.

Once the system has reached target reliability, ELCC can be calculated for either existing or new candidate resources. The calculation is a three-fold process:

1. The LOLH for the electric system without target resources is simulated. If the resulting LOLH does not match the specified reliability target, the system is "adjusted" to meet the target reliability standard (e.g. 2.8 hours/yr). This adjustment occurs through the addition (or removal) of a perfect capacity resource to achieve the desired reliability standard.
2. Target resource is then added to the system and the LOLH is recalculated. This will result in a reduction in the system's LOLH, as the amount of available generation has increased.
3. Perfect capacity resources[4] are removed from the system until the LOLH returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of target resource (measured in MW); this metric can also be translated to a percentage value by dividing by the installed capacity of the specified resource. (i.e. average ELCC)

[4] A perfect capacity resource is an ideal generator that is available in all hours at full capacity. ELCC for a perfect capacity resource is 100%. It's used as a reference to measure how much a resource contributes to system reliability.

Figure 5. Overview of ELCC Approach

1

Calibrate existing system to target LOLH standard

If necessary, add or remove "perfect capacity" to achieve target standard

2

Add desired resource to portfolio

Addition of new source of generation will decrease LOLH relative to measurement in Step 1

3

Remove perfect capacity until target LOLH is restored

Removal of perfect capacity results in increase in LOLH until original target is met

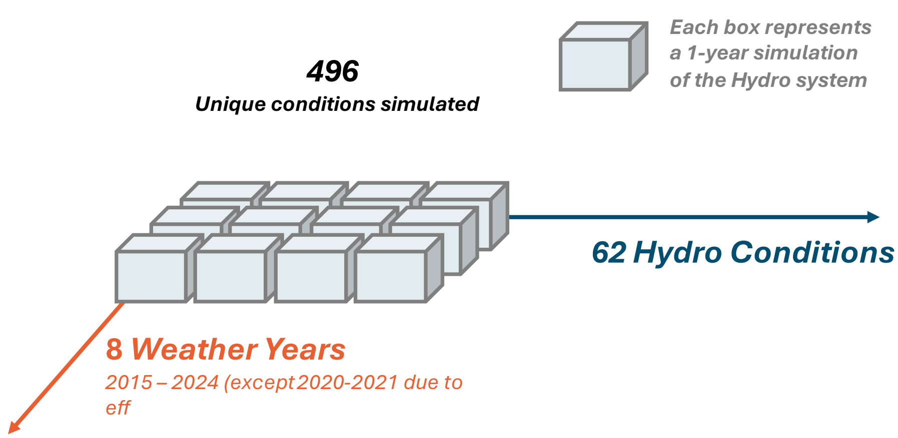
A resource's ELCC is equal to the amount of perfect capacity removed from the system in Step 3

This methodology ensures that the ELCC of a resource corresponds to its contribution towards resource adequacy. By simulating the NL Hydro system across a wide range of weather years and hydrology conditions, RECAP captures the variable generation pattern of resources and quantifies their contribution towards resource adequacy by measuring its substitutability for perfect capacity.

2.2 Detailed Modeling Methodology for NL Hydro System

To capture reliability risks across multiple dimensions of the system, RECAP is used to simulate the NL Hydro system across a combination of weather years and hydro years. Load shaping and renewable profiles are developed consistently within each weather year, while the hydro assets dispatch is evaluated against different hydro years with varying hydrological conditions. Importantly, the model structure matches each hydro year with each weather year over the different horizon, ensuring that it evaluates all possible hydro conditions against realistic weather scenarios. Figure 6 illustrates the characteristics and length of simulation, which are also discussed in more detail below.

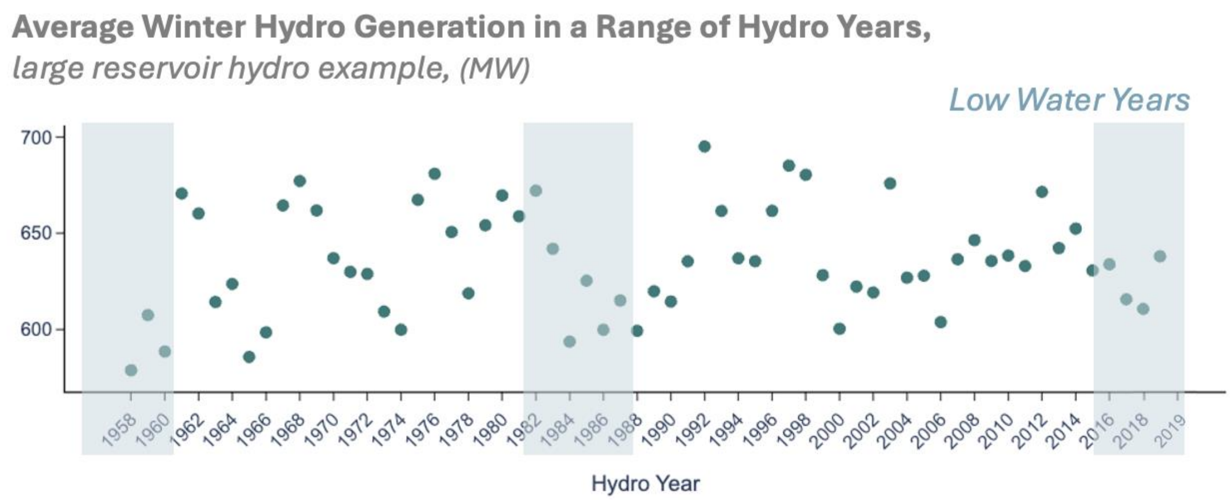
Figure 6. RECAP Weather Year & Hydro Condition Simulation Illustration



2.2.1 Island Hydro Assets Dispatch

Hydro assets production in RECAP was modeled using a long history of simulated generation data provided by NL Hydro, covering the period from 1958 to 2019 (62 years). These simulations, developed in the Vista model,[5] are based on historical hydrological records and capture the variability of inflows across the province's hydro systems. Certain periods stand out as extended drought sequences that affected both large reservoirs and smaller hydro units—for example, 1958–1961 and 1984–1988. By incorporating this full hydrological record, RECAP ensures that hydro modeling reflects the potential variability in wet or dry conditions across multiple hydro years.

Figure 7. Vista Simulated Hydro Generation by Hydro Year



E3 modeled hydro resources within two categories: flexible and non-flexible assets. **Flexible resources** are large reservoir hydro facilities with sufficient storage and operational flexibility to adjust generation on an hourly basis in response to system needs. In RECAP, these resources are modeled with varying monthly energy budgets, allowing them to ramp up or down as needed. This representation better reflects how large storage reservoirs are operated in practice, enabling the model to capture their role in meeting peak demands and responding to reliability events. Bay d'Espoir and Cat Arm are examples of flexible resources, given their large reservoirs and operational flexibility.

Note that in Vista simulations, hydro units are dispatched economically to meet load, which means they are not always operated at their maximum available capacity. However, these units are technically capable of ramping above simulated dispatch levels up to their nameplate capacity for extended periods if needed. To address this limitation in the Vista dataset input, this study assumed certain flexible resources (Bay d'Espoir, Cat Arm, Granite Canal, Hinds Lake, Upper Salmon) could produce at their maximum nameplate rating for all hours in critical winter periods (January and February). This assumption allows the units to provide their full contribution during potential loss-

[5] NL Hydro used Vista model in 2024 Resource Adequacy Plan to generate forecast of average hydraulic generation across historical years.

of-load events. This maximum was held constant across all hydro years for these two months, while the remainder of the year continues to reflect the variation in monthly budgets derived from the historical simulations.

Non-flexible resources include small hydro facilities with minimal storage or run-of-river conditions that offer limited operational flexibility. RECAP represents these resources with fixed generation profiles derived from simulated historical production. This conservative assumption constrains their output to observed patterns, ensuring their contribution to the system is captured without overstating their dispatchability.

Due to the resolution limits in historical simulations, the generation profiles for non-flexible hydro resources were constructed assuming flat generation throughout each day of a given month, based on simulated monthly output from Vista. This produced profiles that vary across months but remain constant within each month, reflecting seasonal production pattern while acknowledging their limited capability to adjust output within shorter timeframes.

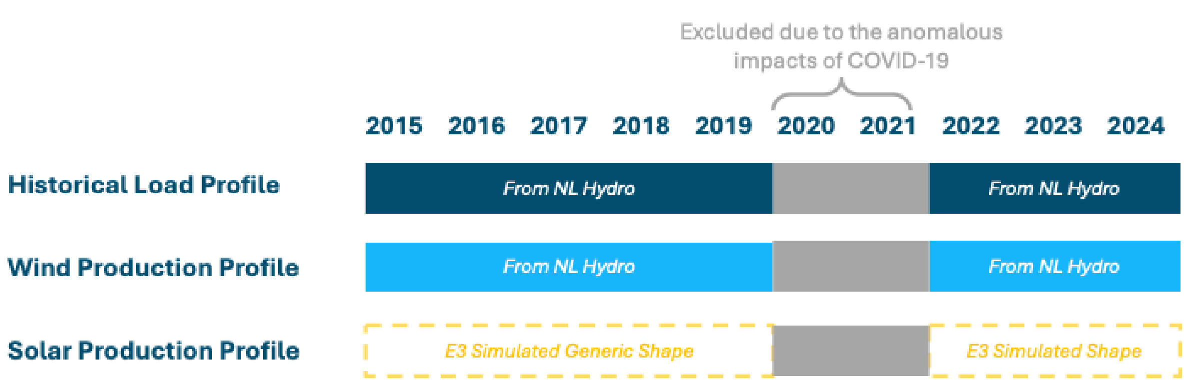
Finally, stochastic outages are simulated randomly for both flexible and non-flexible hydro resources. For larger plants with multiple units, outages are modeled at the unit level to more accurately represent how partial outages may affect system reliability.

2.2.2 Load and Renewable Profile Development

This study relied on historical time-synchronous load and renewable (especially wind) profiles from 2015-2024 in the simulation. These historical records capture both the range of variability of each as well as the key correlations between them, which is a necessary step in resource adequacy modeling.

For load, given the anomalous impacts of COVID-19, this study excluded the years 2020 and 2021, while the remaining years formed the basis of the load shapes. For wind, hourly production data from two existing wind farms on the NL Hydro grid were used, with only the years overlapping the selected load years included in the simulation. For solar, where historical data is not available, a representative island-based annual production profile was developed and then applied across all weather years.

Figure 8. Load and Renewable Profile Input Summary



2.2.3 Storage and Demand Response

Currently, the NL Hydro system has a substantial number of demand response programs, which can provide important load flexibility during reliability challenges. Dedicated energy storage (e.g., lithium-ion batteries) has not yet been deployed, but is also anticipated to become an important addition going forward. In order to accurately capture the energy limitations these resources have in terms of the duration and frequency with which they can provide energy to the electricity system, they are dispatched in a time-sequential way in RECAP over the entire time horizon.

When it is needed, demand response resources can be called in the model for a limited number of times over a defined time period, mirroring existing programs. For example, a demand response program may sign up customers with the promise that they will only need to curtail their load up to 10 times per year. RECAP models demand response with both limits on the number of times that a resource can be called in a given period and a maximum duration of a response when a customer responds to a call.

Similarly, storage resources are dispatched for the purposes of reliability such that they only discharge energy to avoid or mitigate a potential loss of load event after all other resources, including demand response programs, have been utilized. Conversely, storage will charge from any available resource if its state of charge is less than 100% and there is available generation in the electricity system not being used to serve load or provide operating reserves. While this mode of storage operation may not be how storage is predominantly used on a day-to-day basis for economics, the model represents it this way to ensure full representation of its potential resource adequacy contributions, under the assumption that the system operator will likely have sufficient foresight into a potential reliability event (e.g. weather forecast of very cold weather) and will modify the charge and discharge schedule in order to ensure maximum reliability value from the storage resource. Storage is modeled using a roundtrip efficiency factor at 85% and a forced outage rate at 5%.

2.2.4 Labrador Island Link Import Availability

The Labrador–Island Link (LIL) is a high voltage DC transmission system from Labrador to Newfoundland. Commissioned in April 2023, it is a relatively new but significant asset for NL Hydro's Island grid. RECAP modeled the LIL import capability through a three-step process designed to capture both physical system limits and operational uncertainties of this major transmission line.

The first step was to determine the Island grid's ability to absorb LIL imports, as a function of hourly Island demand and Maritime Link (ML) exports. The key characteristics here are that the operational limits differ depending on whether ML exports are below or above 150 MW relative to Island demand[6]. Additionally, although the LIL was designed for 900 MW, this study assumes a maximum import rating of 700 MW, reflecting the current limit until the high power test to 900 MW is completed. An

[6] This analysis is based on the load shedding scheme currently used on the NL Hydro Island grid. The study also examined an enhanced load shedding scheme (Full UFLS) and found that it has limited impact on the Island grid's risk profile.

8,760-hour profile was developed to reflect how LIL imports vary with hourly demand conditions and concurrent ML exports at the end of this step.

Next, the analysis accounted for hydrological constraints at Muskrat Falls, the primary source of LIL imports. As a conservative assumption, this study assumes Muskrat Falls generation was the sole supply for imports, excluding other non-firm transfers. This assumption makes Muskrat Falls generation the limiting factor for LIL transfer capability during critical winter periods. In RECAP, LIL imports were capped to Muskrat Falls generation simulated for the 1988 hydro year, which represents an average inflow scenario.

Finally, given the limited operational experience and potential cascading impact of an LIL trip, the analysis simulated stochastic outages on the LIL to account for its reliability risks. A 5% generic forced outage assumption was applied to the bipole, represented as full on/off capacity events at 700 MW[7]. This stochastic treatment of outages captures the variability and potential interruptions in LIL availability.

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[7] This study also evaluated 3% and 1% generic forced outage assumptions and found that these variations have limited impact on the timing of the greatest system needs; consequently, the capacity contributions (ELCCs) from wind and storage resources are not expected to change materially under different LIL FOR assumptions.

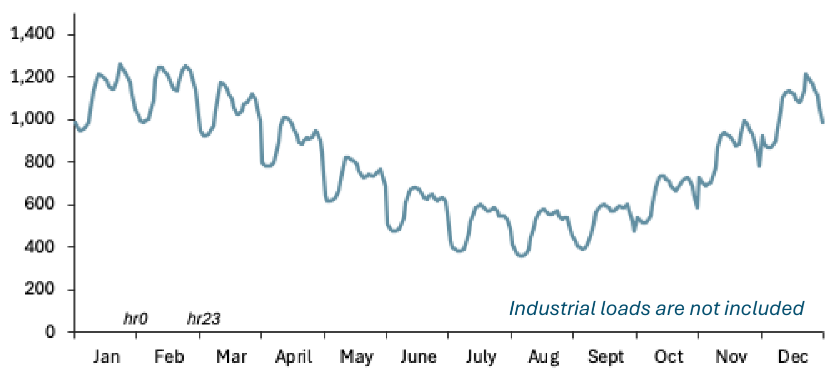
3. Modeling Inputs and Assumptions

3.1 Electricity Demand Forecast

Over the past decade, the island system's total energy demand has remained largely stable, with about a one percent decline between 2015 and 2024. A key feature of this period has been the variability in peak demand. In 2019, peak load was roughly five percent higher than in a typical year such as 2017. This was followed by a sharp drop of around 250 MW between 2019 and 2021 due to the impacts of COVID, before partial recovery in subsequent years.

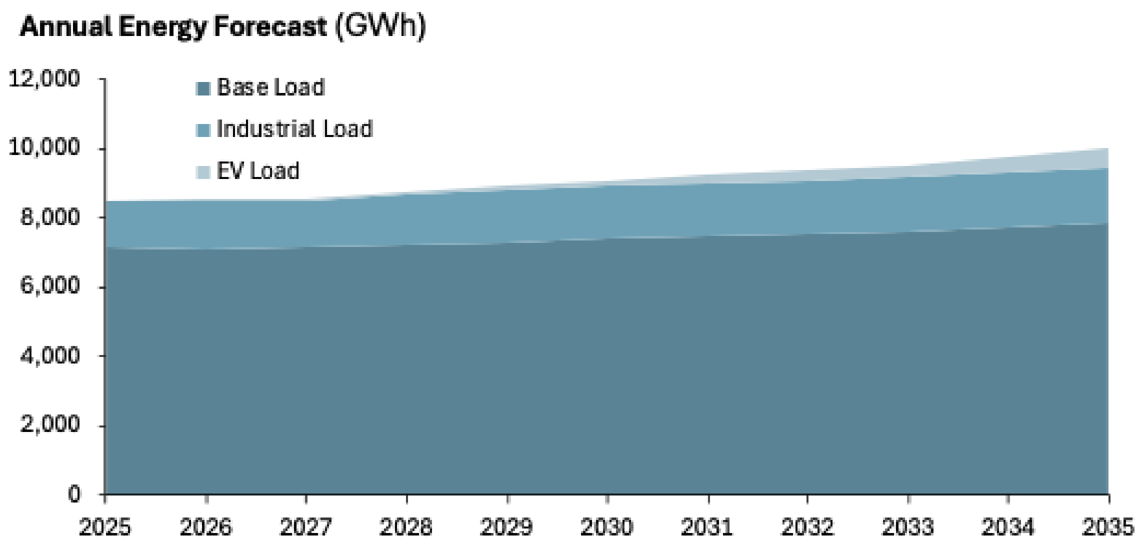
NL Hydro is a distinctly winter-peaking system - the highest demand occurs in December, January, and February, with particularly pronounced peaks in early morning and evening hours. These load characteristics are consistent with strong heating requirements and residential usage patterns. They also highlight the operational challenges of meeting demand during sustained cold periods, when system stress is greatest.

Figure 9. Historical Average Base Load Shapes by Month and Hour of Day, 2015-2024



Looking forward, load forecasts on the Island grid show gradual but steady growth. Baseload demand, adjusted downward to reflect future energy conservation and demand management (ECDM) adoption, is expected to rise over time. Historically, Island load has included only limited amounts of transportation electrification, however, future projections anticipate significant new demand from electrification, particularly electric vehicles. Additional growth is also expected from industrial loads. Under the reference case, annual energy requirements are expected to grow at an average rate of about 1.5 % per year between 2024 and 2034. Peak demand follows a similar trajectory, base load peak forecasts increase in the mid-2020s to the early 2040s.

Figure 10. Island Grid Annual Energy Forecast, 2025 - 2035



The reliability needs of the NL Hydro Island system are currently driven largely by winter peak load events, and this is expected to remain the case in the future as demand grows from industrial activity and transportation electrification.

3.2 Operating Reserves

In addition to load demands, RECAP explicitly included operating reserve requirements that must hold during potential load shedding events. This study included 70 MW of regulating reserves in the model, considered essential to maintaining real-time reliability. NL Hydro also holds a spinning reserves (10 Minute and 30 Minute Reserve) requirement, but is excluded in RECAP, as they're likely to be depleted before critical periods when the system has to shed load.

A critical question for NL Hydro going forward, but one that was outside the scope of our study, is the impact of LIL operation on the need for contingency reserves. NL Hydro's current method of determining contingency reserves in the context of its resource adequacy need determination does not consider the impact of a sudden loss of the LIL, which would need to be made up for with resources on Newfoundland Island. Explicitly modeling the need to carry operating reserves for this contingency may impact the ELCC values of resources that can provide them, e.g. hydro or battery storage. Battery storage, in particular, may be able to contribute to resource adequacy through continuous provision of reserves without the need for energy to replenish its state-of-charge. This would result in a higher ELCC than is indicated here.

3.3 Existing and Planned Resources

Currently, the NL Hydro Island system is supported by a diverse mix of hydro, thermal, wind resources, and the major LIL transmission line that delivers Muskrat Falls energy to the island. Hydro resources remain the backbone of the system, contributing roughly 1,270 MW of installed capacity. This is complemented by up to 700 MW imports through LIL, and approximately 800 MW of thermal capacity. In addition, NL Hydro has power purchase agreements with two wind projects at St. Lawrence and Fermeuse, totaling 54 MW, and NL Hydro has implemented 132 MW of demand response programs that enable customers to provide load flexibility to the grid. Together, NL Hydro has a diverse portfolio of dispatchable resources, variable renewables and demand-side flexibility.

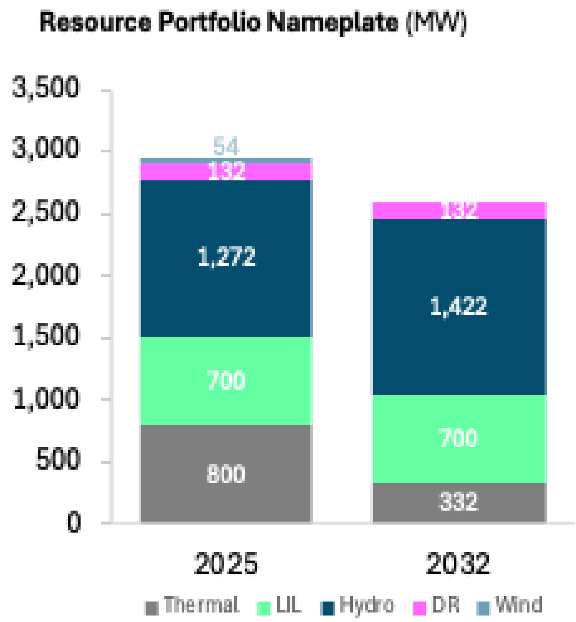
By 2032, the supply mix is expected to undergo a substantial shift. Hydro resources remain the dominant assets on the grid, and Muskrat Falls will continue to deliver clean energy through the LIL. However, the wind PPAs are scheduled for retirement by 2029, and NL Hydro's thermal fleet is planned to decline to 182 MW after a series of retirements. As shown in the table below, the largest reduction comes from the retirement of approximately 490 MW of Holyrood Thermal Generating Station. These retirements represent a significant loss of firm, dispatchable generation. To help offset these retirements and support reliability as demand continues to rise, NL Hydro has identified and planned for new resource additions. This includes the Avalon CT, a 142 MW thermal unit made up of three equally sized combustion turbines, and an expansion at Bay d'Espoir that increases its capacity from 613 MW to 767 MW. The chart below compares the Island's resource portfolio in 2025 and 2032.

Table 2. List of Resource Retirements / Additions by 2032

Date	Plant Name	Nameplate Capacity (MW)
	Retirements	
2026-04	Rattle Brook	4
2030-04	Holyrood Thermal	490
2030-04	Hardwoods CT	50
2030-04	Stephenville CT	50
2030-04	NP Greenhill & Wesleyville	28[8]
	Total Retirements	***622 MW***
	Additions[9]	
2029-12	Avalon CT	*142*
2031-05	BDE Unit 8	*154*
	Total Additions	***296 MW***

[8] Newfoundland Power has proposed refurbishing these two units in 2028 and 2029, which would increase the capacity to 48 MW. Since this has not been approved by the Public Utilities Board it has not been included in this analysis.
[9] Planned additions are subject to regulatory approval.

Figure 11. Existing and Planned Resource Mix in 2025 vs. 2032

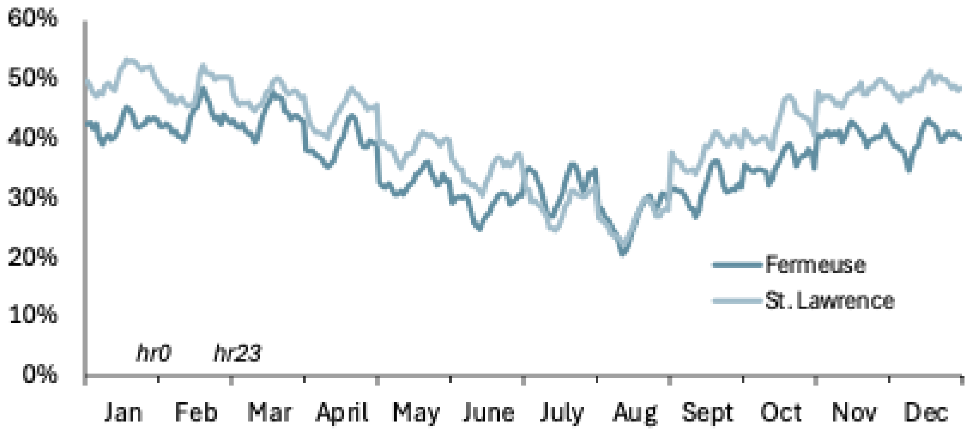


List of Existing Thermal Units	Capacity (MW)
Holyrood Thermal Units*	490
Hardwoods GT*	50
Stephenville GT*	50
Newfoundland Power - Greenhill and Wesleyville*	28
Hawkes Bay Diesels	5
Holyrood Diesels	12
Holyrood GT	123.5
St. Anthony Diesels	9.7
Corner Brook CoGen	15
Newfoundland Power - Thermal	16.5
*** Units retire by 2032**	

3.3.1 Wind

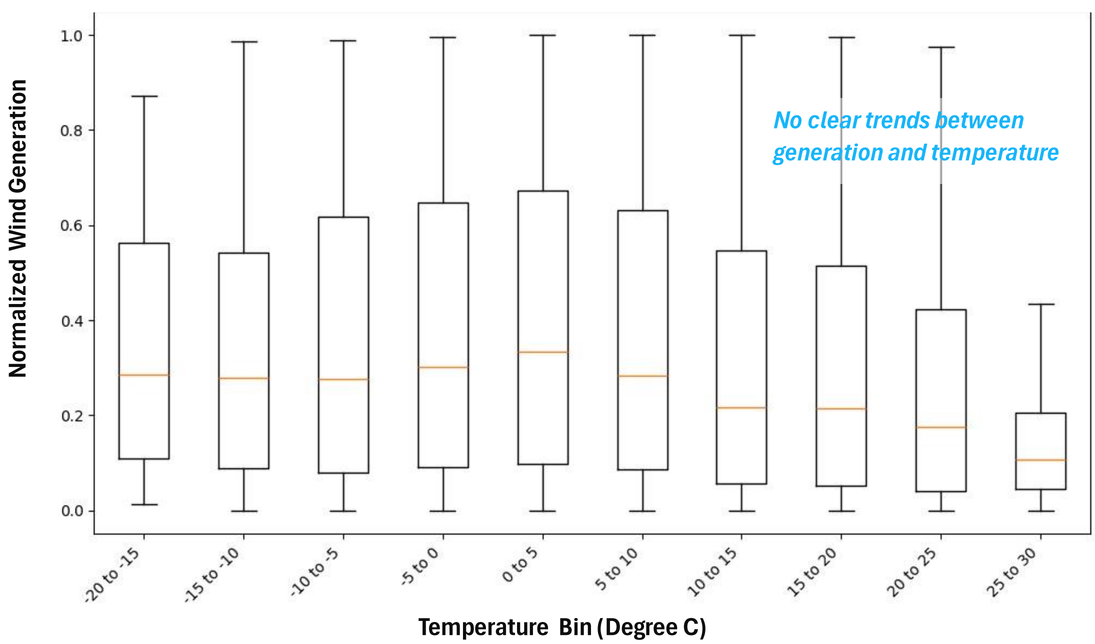
NL Hydro currently operates two wind resources within its service area—St. Lawrence Wind and Fermeuse Wind—each with a capacity of 27 MW, and both PPAs are set to be expired by 2029. Their generation peaks in winter months, with an average winter capacity factor at 48% (St. Lawrence) and 41% (Fermeuse). The profiles exhibit certain intraday variability, within 2-3% variation on an average basis, but can fluctuate significantly within and across individual days, given different weather conditions. Generally, NL Hydro can leverage its highly flexible hydro assets to ramp up or down to balance short term changes in wind generation. That said, if and as intermittent renewable generation grows, the system is likely to require balancing resources, such as fast-ramping thermal generation, hydro, or battery storage, to smooth out short-term variations and enhance system's ability to integrate variable wind generation.

Figure 12. St. Lawrence and Fermeuse Month-Hour Average Wind Generation, 2012-2024



Given the potential impact of cold weather on wind generation performance, this study also examined the relationship between temperature and output from an existing wind farm (around Fermeuse) on the island. As shown in the chart below, the available data, though limited, does not indicate a strong inverse correlation between wind generation and cold temperatures. However, this remains an important factor to monitor, as reduced wind performance during cold days, which also coincides with peak demand, can pose additional reliability risks.

Figure 13. Wind Production and Temperature Relationship (FER Wind)

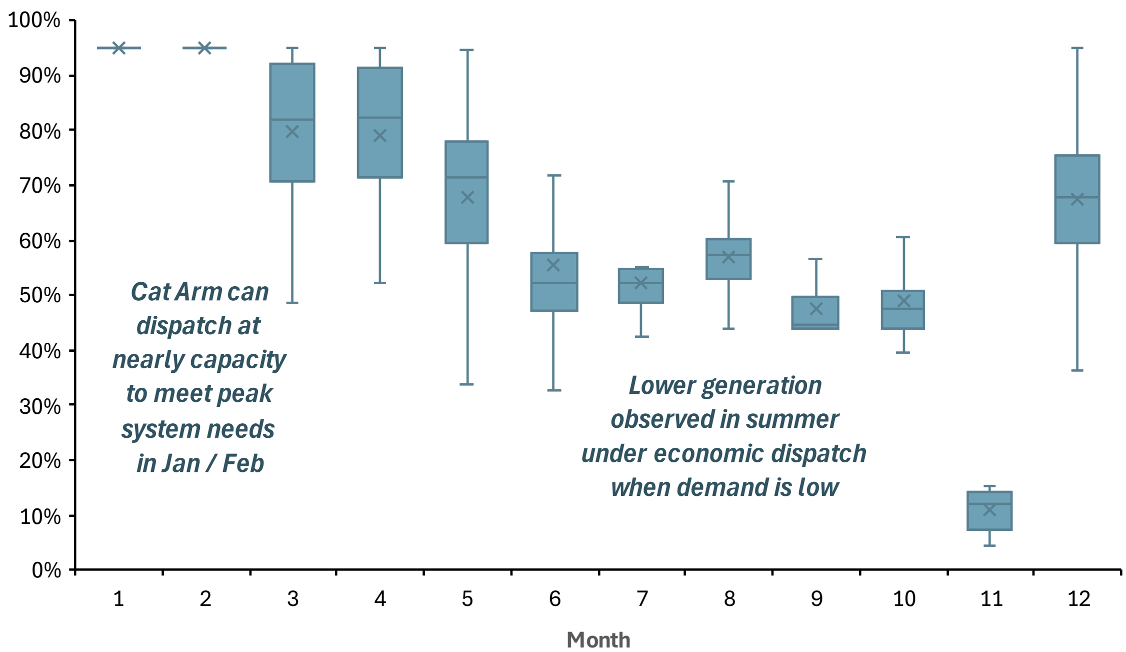


3.3.2 Hydro Assets

As mentioned in Section 2, hydro assets on the Island system are distinguished between flexible and non-flexible resources based on their physical operational characteristics.

As an example, the chart below illustrates the monthly energy budget for Cat Arm, showing how available energy varies across different months of the year (except for January and February, where it is assumed to be capable of generating at maximum historical rating for all days in the two months).

Figure 14. Cat Arm Monthly Budget Distribution Across Hydro Year, 1958-2019



Non-flexible hydro resources, on the other hand, have profiles that vary across months but remain flat within each month, without reflecting daily or hourly fluctuations.

The table below summarizes the hydro assets modeling assumption in RECAP.

Table 3. Summary of Hydro Assets Modeling Input

Resource	Installed Capacity (MW)	Category	Hydro Year Modeled
Bay d'Espoir (8 units)	767	Flexible Hydro	1958-2019
Upper Salmon	84	Flexible Hydro	1958-2019
Granite Canal	40	Flexible Hydro	1958-2019
Cat Arm (2 units)	137	Flexible Hydro	1958-2019
Hinds Lake	75	Flexible Hydro	1958-2019
Paradise River	8	Non-Flexible Hydro	1958-2019
Deer Lake Power	104	Non-Flexible Hydro	1958-2019

Newfoundland Power Hydro *(Avalon + Off Avalon)*	94.2	Non-Flexible Hydro	1958-2019
Exploits *(Bishop Falls + Grand Falls)*	93.8	Non-Flexible Hydro	1958-2019
Star Lake	18	Non-Flexible Hydro	1958-2019

3.3.3 Demand Response Programs

NL Hydro has implemented four major demand response programs. The program design details are described below.

Table 4. Description of Demand Response Programs Implemented in NL Hydro Island System

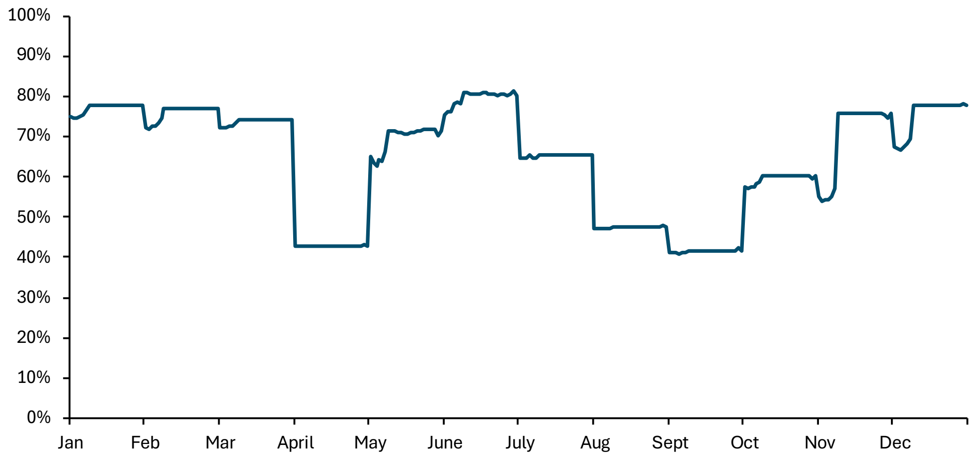
Program	Program Characteristics
CBPP	Up to 90 MW during Winter, and 50 MW during Summer for 6 hours. Total number of calls cannot exceed twice a day and 30 calls annually.
Vale	Up to 8 MW between December and May for 6 hours. Total number of calls cannot exceed 20 calls annually.
NP Capacity Assistance Program	Up to 12 MW across the year for 4 hours. Total number of calls cannot exceed 20 calls annually.
MUN Capacity Assistance Program	Up to 21.7 MW across the year for 4 hours. Total number of calls cannot exceed 20 calls annually. [10]

3.3.4 Imports and Exports

As discussed in Section 2, the LIL is the sole transmission line delivering firm energy from Muskrat Falls to the Island. The chart below shows the month-hour average LIL deliverability modeled in this study. The variance in transfer capability reflects differences in Muskrat Falls generation simulated across hydro years.

[10] Hydro is expecting to enter into this Capacity Assistance Agreement in 2026. The terms of the agreement have not been finalized

Figure 15. Month-Hour Average LIL Import Capability Illustration



In addition to LIL imports, the Island grid is also connected to neighboring systems through the Maritime Link (ML). The Maritime Link is a 500 MW transmission connection between Newfoundland and Nova Scotia. NL Hydro holds a contract for firm energy exports to Nova Scotia of 158 MW from hour 7 to hour 23 each day, while the rest of exports over the line are considered non-firm capacity[11]. In RECAP, only the 158 MW firm export obligation was represented, with the caveat that exports will not be supplied when LIL is not in service.

3.4 Candidate Resources

To evaluate the capacity contribution of potential new resource additions on the Island grid, E3 assessed a range of resource options, including solar, wind, and battery energy storage (BESS) resources. The table below summarizes the incremental levels (tranches) evaluated for each resource type.

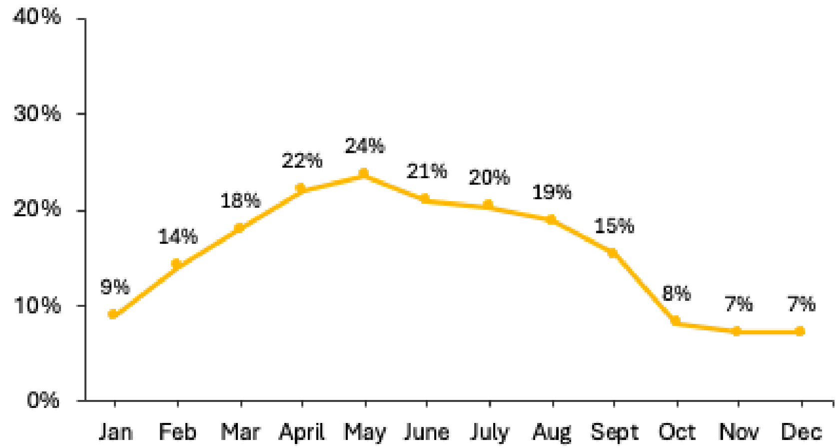
Table 5. Candidate Resource and Size modeled in ELCC Evaluation

Resource	Incremental Addition Size (MW)
Solar	20
BESS (4-hour and 8-hour)	25, 50, 100, 150, 200, 250, 300, 350
Wind	50,100,150, 200, 250, 300, 350, 400, 450, 500

For solar resources, a representative generation profile was applied based on a generic island-based dataset. As illustrated in Figure 16, solar production is higher in spring and summer months, with winter average capacity factor ranging from 7% to 14%.

[11] The supplemental energy contract with Nova Scotia concludes in 2026 and therefore is not included in this analysis.

Figure 16. Representative NL Hydro Solar Monthly Capacity Factor (%)



For wind resources, generation profiles were derived from existing generators in the NL Hydro system, ensuring that the modeled output reflects observed operational characteristics on the island.

For storage resources, E3 evaluated both 4-hour and 8-hour duration options. A 5% forced outage rate was assumed for the base case, based on observations and operational experience from more mature markets such as CAISO. A higher 10% forced outage rate was also tested to reflect potential performance challenges under colder operating conditions in Newfoundland and Labrador.

4. Modeling Results and Discussion

4.1 Characterization of Reliability Risks in 2032

This section presents detailed results of the 2032 load and resource balance analysis for NL Hydro's system. The simulations provide an enhanced understanding of the seasonality and timing of reliability risks present in the portfolio – and, by extension, how effective different types of resources may be in addressing those risks. Figure 17 summarizes the timing of loss-of-load risk by month and hour of day. As shown in the chart, the periods of highest risk in the NL Hydro system are concentrated in the winter early morning and evenings (specifically, in January / February between hour 7:00 to 11:00 AM or 17:00 to 20:00 PM), as the highest heating loads coincide with a LIL outage. In fact, over 90% of simulated loss-of-load events are driven by stochastic LIL outages, which take maximum 700 MW of capacity imports offline.

Figure 17. Relative Loss of Load Probability in 2032 by Month and Hour of the Day

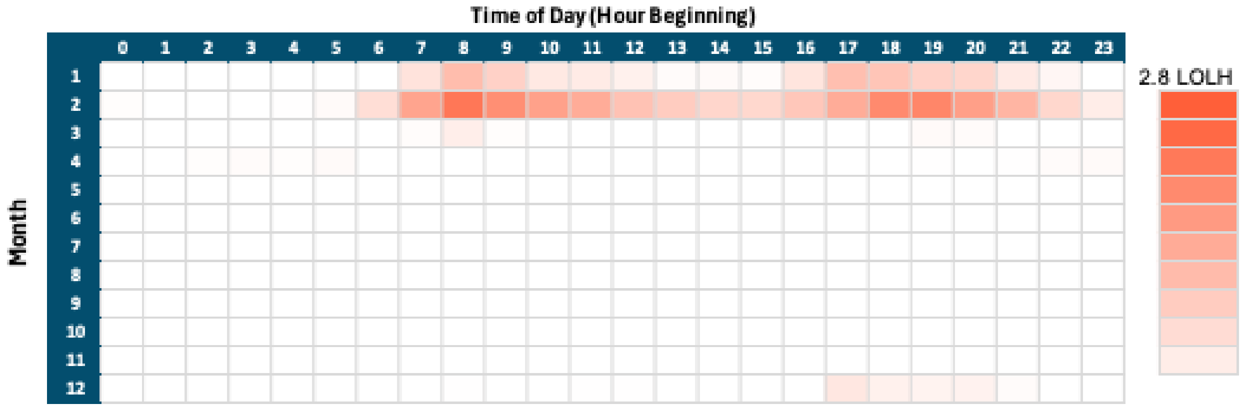


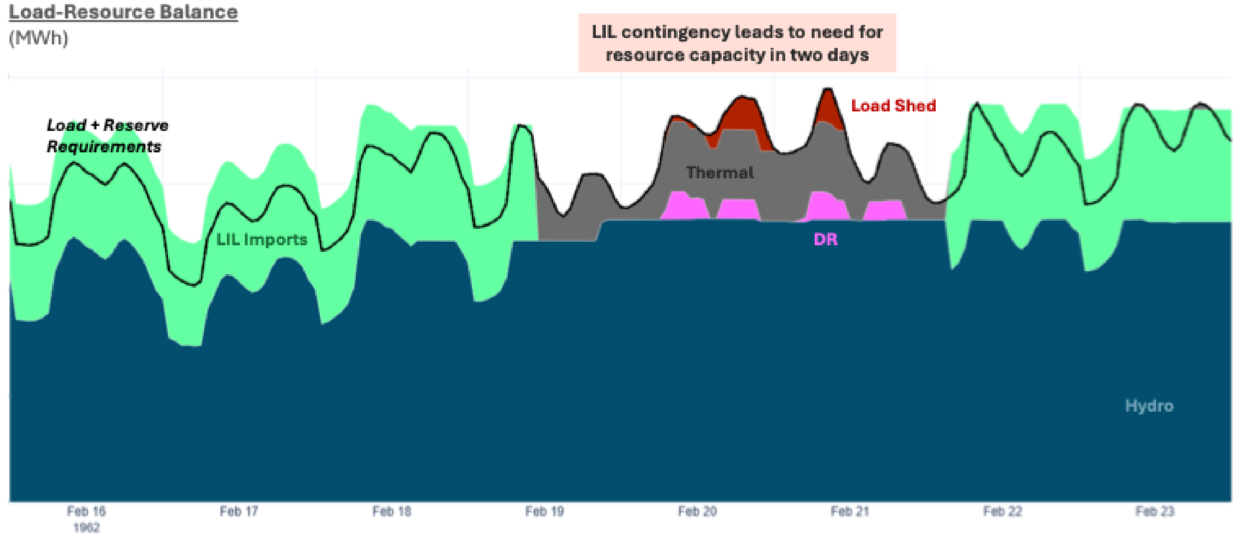
Figure 18 illustrates an example of a system loss-of-load event. In this sample week, the LIL is tripped offline between February 19th and February 21st, reducing import availability to the island from Labrador. In response, 158 MW of Maritime Link exports are curtailed, and hydro assets ramp up to meet the system's capacity needs. Even with all reservoir hydro dispatched at maximum output, however, the system remains at risk of insufficient capacity to serve load, leading to a potential load-shed event lasting 17 hours. This example is instructive as to the nature of reliability risks on the island system:

1. The need for additional capacity is most acute during the coldest winter months when the 700 MW transmission line is unavailable. While the system generally has sufficient energy given its hydro-dominated nature, insufficient capacity can be a bottleneck and drives most of the loss-of-load risks.
2. Existing demand response programs are helpful mitigating resources needed for a short duration (4-6 hours depending on specific program call duration design) and spreading loss-

of-load risk across longer periods of hours, sometimes extending from early morning into the evening. This implies that the marginal contribution of additional energy-limited resources (e.g. 4-hr battery storage) will be relatively constrained.

3. Wind resources, which typically generate more in winter, could help offset these risks. The exact capacity value accreditation depends on the resource's performance (e.g., capacity factor) during extreme cold winter periods.

Figure 18. Illustrative Resource Dispatch in a Challenging Winter Week



4.2 Incremental Resource ELCC Analysis

This section details the incremental capacity value different resources can provide to the island system. Each resulting table or chart shows the incremental capacity value to the 2032 existing and planned resource portfolio. The results are presented in two ways:

1. Cumulative capacity value in perfect MW (or effective MW) – This measures a resource's ability to contribute to the total reliability need.
2. Marginal ELCC as a percentage of each addition – As each new addition of the same or mixture of resources are added to the system, this measures the marginal effectiveness of an incremental tranche of a resource.

4.2.1 Solar

Solar resources are found to contribute very little to system resource adequacy. As shown in Table 6, a representative 20 MW solar project provides just 2.2 MW of firm capacity, an 11% marginal ELCC. This modest contribution reflects both the low solar capacity factor (~14%) in the region and the misalignment between midday solar output and early morning / evening net peak periods, when resource adequacy risk is most severe. As a result, while solar can diversify the portfolio and add more clean energy generation to the grid, it plays only a limited role in supporting reliability needs.

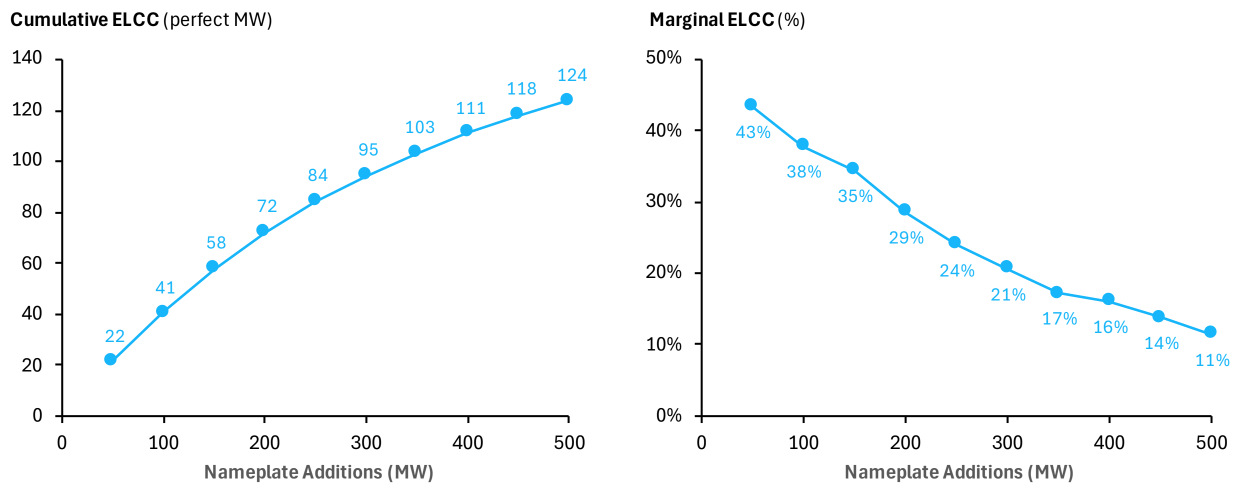
Table 6. Generic Solar ELCCs

Resource	Nameplate Addition *(MW)*	Cumulative Capacity Value *(MW)*	Marginal ELCC *(%)*
Generic Solar	20	2.2	11%

4.2.2 Wind

Wind resources, on the other hand, provide substantially higher adequacy contributions because their generation is more often overlapping with evening peak demand periods. An additional 50 MW of generic wind farm on the island can deliver~ 22 MW of effective capacity, equivalent to a 43% ELCC. However, as wind penetration increases, marginal ELCC steadily declines - its ELCC falls to 29% by 200 MW or 16% by 400 MW. This outcome highlights the "saturation effect," where each additional tranche of wind shifts peak reliability risk into hours of lower wind availability, makes incremental wind capacity lower.

Figure 19. Wind Cumulative and Marginal ELCCs



Comparison to 2024 RRA Results

The calculated ELCC for wind resources differs significantly from the previous study, completed in 2018. The ELCC calculated for two existing wind farms at St. Lawrence and FER was much lower in the earlier study, averaging 22% for the two 27 MW size wind facilities. While it's hard to definitively measure all of the exact differences in inputs and updates from the prior study to this one, the table below describe the key distinctions between the two studies.

Table 7. Summary in Methodology and Input Updates between Two Studies

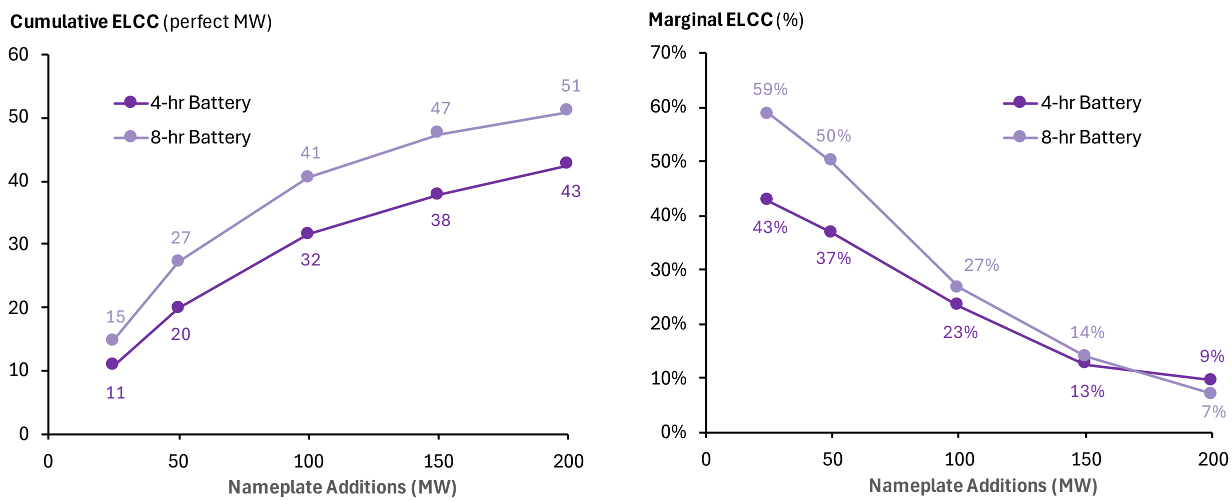
Factor	Type	Description
Model	Methodology	E3 uses RECAP and the prior study used NL Hydro's own reliability model in PLEXOS. The main difference between the two is the sampling for wind profiles – the former preserves the correlation between load conditions and wind generation, while the latter draws profiles randomly.
Study Year	Methodology	The prior study measured ELCCs for two existing wind farms in 2024. This study explores incremental ELCCs for similar wind turbines in nearby locations assuming they are operated in 2032. The disparity in study year alone makes this current study not directly comparable due to shifts in loads and resources.
Increased Weather Variability	Input	The prior study uses one hourly load profile for a base weather year whereas this study uses 8 (2015-2024, except 2020-2021) weather years. This increase in weather years ensures a more complete representation of weather-dependent wind performance during challenging periods.
LIL Forced Outage Rate	Input	The prior study used a LIL bipole FOR of 1 hour per year (0.0114%) whereas this study uses a FOR of 5%. This has significant implications on the outage profile in the model (specifically, timing of the most resource needs) and the ELCC results.
Increased Stochasticity	Input	In addition to the increased weather variability, this study captures a wider range of plausible load, hydro, and wind combinations by explicitly mapping hydro availability to load and resource performance across the full set of simulated scenarios.

Taken together, these updates help explain the higher incremental ELCCs for wind in this study. The most direct factor is the involvement of system loss-of-load size and timing. With the retirement of Holyrood TGS and increased reliance on the LIL, the Island system has become more capacity-constrained, with most loss-of-load risk occurring during winter peak periods coinciding with LIL outages. By contrast, the 2024 study assumed a more diverse portfolio (e.g., including two existing wind farms and Holyrood TGS), where loss-of-load events were not concentrated solely in the winter but also occurred in early spring, when wind performance is weaker, resulting in lower ELCC values.

4.2.3 Storage Resources

In hydro-dominated systems, storage can be a valuable resource adequacy resource as it can be reliably charged from surplus hydro generation and dispatched later during system needs. This study focuses on the incremental capacity value of storage with two different durations: 4-hr and 8-hr.

Figure 20. 4-hr and 8-hr Storage Cumulative and Marginal ELCCs



Assuming a 5% forced outage rate for battery technologies, 25 MW of 4-hour batteries can contribute ~43% of nameplate as effective capacity, while 8-hour storage performs better, maintaining ELCCs of over 50% in the first 50 MW addition. The ability to sustain output across extended peak periods allows longer 8-hour duration storage to cover more of the system's risk hours, making it more effective in supporting reliability. However, like wind resources, batteries experience diminishing returns due to the inability to meet increasingly long duration reliability requirements at higher penetrations of these resources. By 100 MW tranche, both 4-hr and 8-hr storage ELCC falls to ~25% and reduces to below 10% after 200 MW addition.

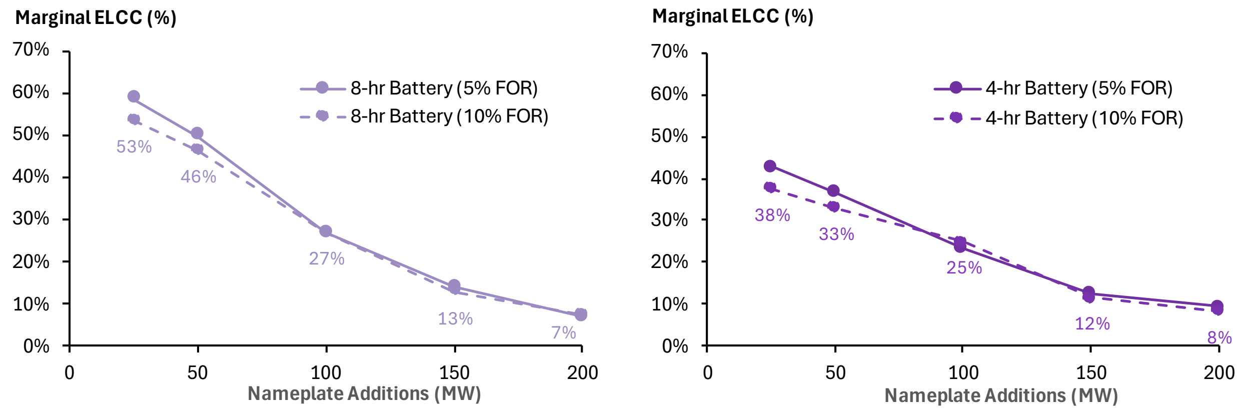
Saturation Effect between Existing Demand Response Programs

Energy-limited resources represent a class of resources that can provide power to a system with a limited amount of energy or duration. Resources like battery storage are key examples, but demand-side resources like demand response that have provisions on how often / how long they can be called on also fall into this category. In fact, combinations of energy-limited resources tend to exhibit an antagonistic relationship due to providing capacity value through the same peak-shaving mechanisms. In the case of the NL Hydro system, the incremental ELCC of storage resources are constrained by the presence of existing demand response programs. Despite being different resources, both target similar dispatch periods, which reduces the marginal value of storage additions. In other words, while batteries remain an important resource adequacy resource, their contribution is somewhat diminished as existing demand response programs with similar operational capabilities saturate the system's highest-value reliability periods and require additional resources to sustain dispatch across a longer window.

Impact of Forced Outage Rate Assumption on Storage ELCCs

This study focuses primarily on characterizing the marginal ELCCs of storage resources assuming a 5% forced outage rate, but explores the impact of this assumption on marginal ELCCs through sensitivity analysis. The chart below shows marginal ELCCs for 4-hr and 8-hr storage assuming a 10% forced outage rate.

Figure 21. Marginal 4-hr and 8-hr Storage ELCCs (assuming 10% Forced Outage Rate)



Under the base assumption, the first 25 MW of 4-hour storage provides a 43% ELCC, while 8-hour storage achieves 59%**.** If outage rates rise to 10%, these values fall to 38% and 53%, respectively. While the absolute reductions appear small, the effect sustains through higher penetrations.

4.2.4 Wind and Storage Resources

ELCC studies for many utilities have shown that the combined capacity value of an entire portfolio is interdependent; that is, changes to the penetration of one resource affects the capacity value of other resource additions. For the NL Hydro system, this study also computes incremental ELCCs for a combination of wind and storage resources, given the potential interactive effects between two resources (i.e., diversity benefits where temporal variation in wind production supports more efficient storage cycling). Specifically, 12 unique combinations of incremental wind and storage capacities are examined. The resulting surface is shown in Table 8, which reports the cumulative incremental ELCC resulting from each combination of wind and storage (for example, an additional 100 MW of storage and 200 MW of wind provides a total of 109 MW of effective capacity incremental to the 2032 base portfolio). As the penetration of either resource increases, the total capacity contribution of the incremental resources also increases (a reflection of their additional reliability contribution to the system).

Table 8. Cumulative ELCC (MW) from Combinations of Incremental Wind and Storage Resources, *on Top of 2032 Existing and Planned Resource Portfolio*

		Incremental 4-hour Storage Capacity (MW)					
		0	25	50	100	150	200
Incremental Wind Capacity (MW)	0	-	11	20	32	38	43
	50	22	33	42	53	60	64
	100	41	53	62	73	80	84
	150	58	70	79	92	99	104
	200	72	85	95	109	118	123
	250	84	98	109	125	135	141
	300	95	109	121	138	150	157
	350	103	117	130	150	164	172
	400	111	126	138	159	175	186
	500	124	139	152	173	191	206

Marginal ELCC curves for both energy storage and wind can be calculated from the table above by comparing how much additional effective capacity is provided by each increment of installed capacity with each step. These are shown in Table 9 (wind) and Table 10 (energy storage). The key observations here are:

1. The marginal ELCC of new wind resources on top of the 2032 existing and planned portfolio is relatively high for the first 50 MW of additions but declines to around 30% at 200 MW of penetration. However, at higher penetrations of storage (e.g., 25 MW to 100 MW), the marginal ELCC of wind at a given penetration increases slightly. For example, at 200 MW of wind, the marginal ELCC rises from 29% to 38% with additional storage. This reflects a diversity benefit where storage mitigates the variability of wind by capturing excess energy during periods of high generation and shifting it to times when wind output is low or demand is higher. In effect, storage smooths out the hour-to-hour fluctuations of wind and increases its effective contribution to system reliability.
2. Similarly, the marginal ELCC of 4-hour energy storage resources is high at low penetrations (greater than 40% of nameplate capacity) but declines as storage penetration increases, since the system increasingly needs resources that can sustain output for longer durations. However, when additional wind is added, the decline in storage ELCC is slightly delayed. For instance, moving from 100 MW to 200 MW of wind, the marginal ELCC of 50 MW of storage increases from 37% to 41%. This again demonstrates the aforementioned diversity benefit between wind and storage: higher wind penetration increases net load variability due to its fluctuating profile, which creates more opportunities for storage to discharge when wind output drops, reinforcing its capacity value.

Table 9. Marginal ELCCs for Wind as a Function of 4-hr Storage Penetration (read down columns)

Incremental Wind Capacity (MW)	Incremental 4-hour Storage Capacity (MW)					
	0	25	50	100	150	200
0	-	-	-	-	-	-
50	43%	44%	44%	42%	44%	42%
100	38%	40%	40%	41%	40%	41%
150	35%	35%	35%	37%	39%	39%
200	29%	30%	32%	35%	37%	38%
250	24%	25%	27%	30%	35%	36%
300	21%	23%	23%	27%	29%	33%
350	17%	17%	19%	24%	28%	31%
400	16%	16%	15%	19%	22%	27%
500	13%	13%	14%	14%	17%	20%

Table 10. Marginal ELCCs for 4-hr Storage as a Function of Wind Penetration (read across rows)

Incremental Wind Capacity (MW)	Incremental 4-hour Storage Capacity (MW)					
	0	25	50	100	150	200
0	-	43%	37%	23%	13%	9%
50	-	44%	36%	22%	14%	8%
100	-	48%	37%	23%	14%	9%
150	-	49%	36%	25%	15%	9%
200	-	51%	41%	28%	17%	10%
250	-	53%	46%	31%	21%	11%
300	-	57%	47%	35%	23%	15%
350	-	57%	51%	39%	27%	17%
400	-	57%	50%	43%	31%	22%
500	-	60%	52%	43%	36%	29%

4.3 Limitations and Recommendations for Future Work

The values and results developed in this study are intended to inform NL Hydro's planning process for the next RRA study.

At the same time, like all studies, this study is subject to limitations, particularly associated with limited operational experiences with newer assets. As NL Hydro gains more experience and as the system evolves, it will be important to proactively evaluate emerging risks and determine whether updates to the analysis are necessary to address specific challenges. Key areas for refinement include:

1. Wind generation profile: The current analysis relies on a limited set of existing wind farms, which may not fully capture the variability of wind performance, especially under extreme weather conditions. Expanding the dataset as new projects come online will enhance NL

Hydro's understanding of this relatively new resource on the island grid and improve the robustness of ELCC results.

2. Labrador–Island Link (LIL) performance: NL Hydro has only a few years of operational experience with the LIL, the sole major transmission line into the island. This study used generic assumptions for forced outage rates and outage durations. As more operational data becomes available, particularly under severe weather conditions, it will help refine the representation of LIL reliability.
3. Labrador–Island Link (LIL) operating reserves: NL Hydro may need to evaluate whether its resource adequacy model should explicitly carry contingency reserves to cover the sudden loss of the LIL, given its role as the island's sole major interconnection and the potential reliability impact of an unexpected outage.
4. New hydro impoundments: Future hydro developments could significantly alter system flexibility and influence the accreditation of other resources such as wind and storage. As projects progress, further work will be needed to assess their contributions to overall system reliability.
5. Load growth: Forecasts remain uncertain, especially in light of electrification, economic growth, and climate change.
6. Other data limitations: Additional uncertainties include resource portfolio changes not contemplated in this study, and the maximum flexibility that can be achieved from hydro assets. Ongoing updates in these areas can help sustain confidence in future results.

Overall, this study provides valuable insights to guide both near-term and long-term planning, but periodic updates will be necessary as NL Hydro gains experience with new technologies and resources, to ensure that its approach remains consistent with best practices and responsive to emerging risks.

5. Conclusion

This ELCC study begins by identifying the reliability challenges that NL Hydro may face in 2032, and then it quantifies the capacity contributions of a range of resources (i.e., renewables, storage) that could enhance the reliability of the island grid. The resulting observations and calculated ELCC values provide critical inputs to NL Hydro's planning process and help NL Hydro develop a portfolio capable of serving load across all hours of the year.

Key findings from this study include:

1. **As Newfoundland and Labrador enter a period of major grid transformation, the periods of greatest reliability risk are expected in cold winter early mornings and evenings.** E3 modeled grid resource adequacy in 2032, a time characterized by retiring assets, new resource additions, and rising electricity demand. The planned retirement of the Holyrood Thermal Generating Station, the province's largest thermal plant, around 2030 will create the need to develop new sources of energy and capacity. At the same time, shifts in consumer behavior,

industrial growth, and evolving climate policies are expected to accelerate electricity demand, emphasizing the need for careful planning to maintain reliability. As shown in the chart below, the periods of highest risk in the NL Hydro system are expected to be early winter mornings and evenings, during the times of the highest winter heating loads.

2. **Newfoundland & Labrador's resource needs.** Given high availability during the winter net peak period, the marginal ELCC for wind begins in the mid-40% and declines with increasing penetration as reliability risks shift towards periods of lower wind output. In contrast, given the poor alignment between peak solar generation (in the midday) and highest system risk (early morning and evenings), the ELCC value for solar is lower (about 11%).

3. **Energy storage may also play a role in meeting NL Hydro's resource adequacy needs, reflected in ELCC values from 40-60% in initial tranches.** New energy storage can charge from surplus hydro generation and discharge during peak periods. That said, due to the flexibility of existing hydro generation as well as the province's extensive demand response programs, the incremental capacity value provided by storage is meaningfully lower than its full nameplate value, i.e., about 43% for the first 25 MW of 4-hour storage and 59% for the first 25 MW of 8-hour storage. At higher levels of storage deployment, as reliability risks extend over longer durations, the marginal ELCC values decline further. These results are lower than in thermal-dominated systems, reflecting the flexibility already provided by Newfoundland and Labrador's flexible hydro resources and the 130+ MW of demand response already on the grid.

4. **The Labrador–Island Link (LIL), a 700 MW high voltage transmission asset from Muskrat Falls, provides a key source of capacity and reliability to the NL Hydro Island system.** Commissioned in April 2023, this asset is relatively new but represents the single largest source of energy to the island. From a reliability perspective, the modeling considered the physical system limits and operational uncertainties of this major transmission line, particularly during the coldest winter months when the system is more constrained. The Labrador Island Link (LIL) delivers large volumes of hydroelectric energy from Muskrat Falls to the island but like any asset, incurs some reliability risk due to its operational uncertainty. A hypothetical outage on this single transmission link could create system-wide adequacy challenges, particularly during winter peaks. This dependence on a single asset influences the types of resources that can provide complementary contributions to the Island's reliability needs.