newfoundland labrador hydro

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October 3, 2022

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

Attention: Cheryl Blundon
Director of Corporate Services and Board Secretary

Re: ***Reliability and Resource Adequacy Study Review***
Reliability and Resource Adequacy Study – 2022 Update

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") 2022 update of its Reliability and Resource Adequacy Study ("2022 Update"), which is filed as a complement to the "Reliability and Resource Adequacy Study"[1] and the "Reliability and Resource Adequacy Study – 2019 Update."[2]

The 2022 Update is comprised of the following:

- Planning for Today, Tomorrow, and the Future – 2022 Update, a summary document that briefly highlights key considerations of the 2022 Update;
- Hydro's Study Methodology and Planning Criteria;[3] and
- Hydro's Long-Term Resource Plan.[4]

The "Near-Term Reliability Report,"[5] will be filed on November 15, 2022, as scheduled.

Hydro remains committed to working with the Board and stakeholders to help ensure an appropriate balance of cost and reliability for the provincial future electrical system.

Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

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[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019.
[3] Included as Volume I to the 2022 Update.
[4] Included as Volume III to the 2022 Update.
[5] Previously Volume II to the Reliability and Resource Adequacy Study.

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Reliability and Resource Adequacy Study 2022 Update

October 3, 2022

newfoundland labrador hydro

A report to the Board of Commissioners of Public Utilities

List of Contents

The components of the Reliability and Resource Adequacy Study – 2022 Update include:

- Planning for Today, Tomorrow, and the Future
- Executive Summary
- Volume I: Study Methodology and Proposed Planning Criteria
- Volume III: Long-Term Resource Plan
- Abbreviations
- Definitions

PLANNING FOR TODAY, TOMORROW, AND THE FUTURE.

2022 UPDATE

newfoundland labrador hydro

Hydro is the people's utility that you can count on—providing safe, cost-conscious, reliable electricity while harnessing sustainable energy opportunities to benefit the people of Newfoundland and Labrador.

THE POWER OF PLANNING

In 2018, Newfoundland and Labrador Hydro (Hydro) completed a Reliability and Resource Adequacy Study (2018 Filing), filed with the Board of Commissioners of Public Utilities (Board) the same year. The 2018 Filing addresses our long-term approach to providing continued reliable service for our customers. This resource planning process provides an in-depth analysis of how much electricity customers will need over the next ten years. We also consider which assets should be maintained and if new assets are required to ensure we have the right energy mix to meet those demands.

In 2019, Hydro completed an update to the 2018 Filing. The 2022 Update is a complement to the 2018 Filing and 2019 Update. It provides additional detail on matters Hydro has continued to investigate, responses to findings and recommendations made by the Labrador Island Link Reliability assessment and the Holyrood Thermal Generation Station Assessment. To meet customer needs, we have completed a resource plan considering a range of possible scenarios over a ten-year planning horizon—covering the period from 2023 through 2032.

We are also planning during a time when the industry is undergoing massive change. The dramatic societal shift towards cleaner, sustainable energy sources is having major impacts on electricity grids and utilities planning for the future. Utilities are having to balance unprecedented growth at unprecedented speed.

WHAT'S NEW IN 2022

Hydro is undertaking this planning process at a time when our province's electricity grid is on the verge of significant transformation—integrating the Lower Churchill Project assets while preparing to respond to a rapidly changing energy landscape. While continuing to provide least-cost, reliable service for our customers, Hydro must consider:

1. How will we meet Canada's goal of a net-zero electricity sector by 2035?
2. How will the Labrador-Island Link operate post-commissioning?
3. How will we meet load growth and demand for electrification?

Given the pace of change in the energy landscape, Hydro will undertake careful planning while making incremental decisions to ensure we adapt to the ever-changing environment. Long-term solutions will evolve as uncertainties become clearer over time. Recommendations put forward in the 2022 Update use current assumptions to provide incremental solutions that will be updated every year.

Throughout this process, we will use available, up-to-date information to make evidence-based recommendations that honour our commitment to climate change action and to meeting the expectations of society and the federal government.

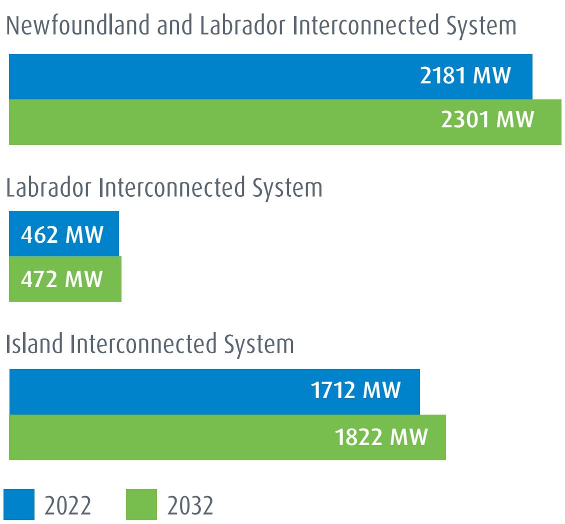
PROVINCIAL INTERCONNECTED SYSTEM

We assess and plan for capacity and energy on a provincial basis, as compared to planning for separate systems. We plan for ten years out to meet current customer demand, as well as the demand for new confirmed customers. While there are many potential customers exploring development in our province, as new requests for interconnection are confirmed, we will update our plans accordingly.

CUSTOMER DEMAND REQUIREMENTS

The current base forecast is expected to grow by 120 MW in the next decade. This forecast does not include potential customer loads not yet confirmed.

Hydro will reexamine system requirements should the base case experience higher load growth.



LABRADOR INTERCONNECTED SYSTEM

The Churchill Falls Generating Station provides energy to the two major customer centres in Labrador East and Labrador West, as well as many homes across eastern North America. The Labrador Interconnected System is connected to the Island Interconnected System via the Labrador-Island Link. The system is also connected to the North American Grid via 735 kV transmission lines from Churchill Falls to Québec.

ISLAND INTERCONNECTED SYSTEM

Most of the energy on the Island comes from hydroelectric generation capability located off the Avalon Peninsula and the bulk 230 kV transmission system extending from Stephenville to St. John's. The system became interconnected to North America for the first time in 2017 via the Maritime Link (which connects to Nova Scotia) and again in 2018 via the Labrador-Island Link (which connects to the Labrador Interconnected System).

REPORT SUMMARY

ASSESSING LIL RELIABILITY

Once the Labrador-Island Link (LIL) is commissioned and existing thermal assets are retired, the island portion of the province will rely heavily on electricity from Muskrat Falls. As part of this planning process, Hydro has worked to understand the implications of LIL reliability to the Island Interconnected System.

To validate Hydro's approach to planning and how LIL should be considered, Hydro worked with third-party consultants that helped inform our planning assumptions, analysis, and processes when considering various scenarios regarding LIL's availability. Consultants recommended Hydro prepare a broad range of scenarios given the level of uncertainty regarding LIL's reliability and the possibility of prolonged outages.

OUR ANALYSIS

We have been listening to customers and stakeholders. Together we want to understand how proposed decisions impact our system and customers.

Following industry best practice, we applied a rigorous modelling process to predict potential impacts. Three separate analyses were performed to assess the impact of LIL reliability on the Interconnected System.

As all utilities do, we examined many factors to determine possible outcomes and associated generation needs required for a series of scenarios. For example, we considered system conditions such as the status of other generation and transmission assets. Since demand on our system is largely driven by weather conditions, we also considered timing of a potential longer LIL outage during a period of extreme weather conditions.

Among the many scenarios we analyzed, we considered an outage of up to six weeks during winter. We examined this scenario to clearly understand the impacts and ensure we are prepared to deliver reliable service when our customers need it most.

Peak demand on the coldest day of the year typically reaches 1800 MW.

The analysis considered the potential ranges for the frequency and duration of outages. The outcome was that load growth, combined with currently planned thermal asset retirements, demonstrates a gap in the ability to supply customers in the scenario where a longer outage occurs during peak times in the middle of a cold winter. In order to close the gap between demand and supply in such a scenario, Hydro will be recommending some actions to ensure reliable supply.

** A detailed analysis, is presented in the comprehensive 2022 Update.*

INSIGHT:

WE NEED TO ENSURE WE HAVE ADEQUATE BACKUP GENERATION, UNTIL NEW SOURCES OF GENERATION CAN BE PLANNED, APPROVED, CONSTRUCTED, AND COMMISSIONED.

Hydro has conducted its analysis consistent with best practices observed across the industry while attempting to manage significant uncertainty. Like many utilities, Hydro must develop strategies to enable the decarbonization of generation assets and address societal decarbonizing impacts on load requirements.

RECOMMENDATIONS

EXPANDED CAPACITY

We must ensure we have the capacity to reliably serve customers and begin to prepare for supplying new customers. New generation will be needed before we can discontinue use of the Holyrood Thermal Generating Station, but this process takes time. A reasonable time frame from decision to commissioning for a new asset is roughly five to eight years, or longer, depending on the type, size, supply, and location of the supply.

The Bay d'Espoir Hydroelectric Generating Station is the largest hydroelectric facility on the Island. Its seven units add 613 MW of capacity to our system. Future expansion had been a consideration at the time of its construction, which would now enable a new unit to be added in an efficient and cost-conscious manner.

As such, Hydro is proposing to review an expansion of firm supply on the Island with primary consideration given to an expansion at the Bay d'Espoir Hydroelectric Generating Station as this was previously identified as the next best resource for the Island. The construction of an additional unit would provide 154 MW of incremental capacity and support the retirement of the Holyrood Thermal Generating Station.

THE FUTURE OF HOLYROOD

The Holyrood Thermal Generating Station has played an important role in the Island electrical system for almost 50 years. Hydro has continued to invest in the facility to ensure reliable service until LIL is commissioned.

Hydro is recommending that the Holyrood Thermal Generating Station, as well as Hardwoods Gas Turbine, remain available as backup generation in the event of a prolonged outage of the Labrador Island Link and until long term sources have been reviewed, approved, and constructed. The use of the thermal units would largely depend on the performance of LIL and system conditions. Continued capital and operating investments would be required to ensure the availability of the units, however every effort would be made to minimize operational costs.

AN ITERATIVE PROCESS

Utility planning is never finished. As the utility responsible for generating the majority of the electricity for our province, it is critical that we are looking ahead and planning for tomorrow as much as today.

The recommendations in the 2022 Update are the next steps toward planning for the future, which may result in additional resources in order to meet various demands such as conversion from oil heating and gas-powered vehicles in an effort to reduce carbon emissions. Long term capacity requirements arising from reliability or load growth needs are still contingent on evolving factors.

As all utilities do, we will continue to assess load growth, asset performance, and demand for energy and capacity on a regular basis. Following this iterative process, we will continue to make evidence-based decisions on future additional supply sources that are right for our province and customers.

WHAT'S NEXT FOR THE INDUSTRY?

Electricity Canada has published that Canada will need 121 TWh of new supply just to replace carbon-based sources of electricity by 2035. This is equivalent to adding about four Churchill Falls or 25 Muskrat Falls.

That 121 TWh is based on current loads. Climate change action requires other industries to decarbonize and move to clean electricity sources. This means the current whole electricity sector will need to grow by a factor of 2 or 3, or more.

As such, electricity system planning processes must evolve to meet these changes and demands. All Canadian utilities, including Hydro, are working to navigate the uncertainty and plan system additions to affect the government policy expectations on climate change.

Our work continues to advance our understanding of this changing landscape and the implications for additional supply recommendations for our province. A review of the following will be included in the 2023 Update expected next Fall:

1. Outcomes of the Labrador Network Additions Policy
2. Impact of electrification, including industrial decarbonization efforts
3. Impact of the evolving wind energy sector
4. Improved understanding of the clean electricity standard
5. Operational data on LIL performance

Electricity rates are a concern for Newfoundlanders and Labradorians, and it is our responsibility to ensure the right balance between reliability and the cost of those investments for customers. While there are always options available to improve system reliability, this can impact rates. Hydro is committed to reviewing such impacts through the transparent process set by the Board and through engagement with customers and stakeholders.

LOOKING AHEAD

The 2022 Update is intended to provide additional information to complement the Board's view of the Reliability and Resource Adequacy Study. We remain committed to working with the Board to determine the appropriate balance of investment cost and system reliability. Hydro will be seeking review of these recommendations with the Regulator in a transparent and public process.

We value the importance of customer input for consideration and decision-making purposes. Customer input, along with analysis and evidence, helps us make informed decisions about the future of electricity in our province.

Hydro expects to launch a customer engagement initiative in 2023, focused on determining the value of additional reliability to customers. This builds on our engagement activities in 2018 and will help shape Hydro's future strategy for investments in the system.

As we continue working with stakeholders to advance our resource plans, and as we gain clarity on many of the uncertainties we face, we will continue to refine and evolve our long-term plans.

YOUR OPINION MATTERS!

Join the NL Hydro Electricity Feedback Panel

www.electricityfeedbacknl.com

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hydro

Reliability and Resource Adequacy Study
2022 Update

Executive Summary

Newfoundland and Labrador Hydro's ("Hydro") "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update") is filed as a complement to the "Reliability and Resource Adequacy Study" ("2018 Filing")[1] and the "Reliability and Resource Adequacy Study – 2019 Update" ("2019 Update").[2] The 2022 Update includes additional detail on system planning matters in consideration of the Labrador-Island Link ("LIL") reliability assessments[3] and the Holyrood Thermal Generating Station ("Holyrood TGS") assessment.[4]

The 2022 Update is presented in two volumes:

1) Volume I outlines Hydro's study methodology and proposed planning criteria; and

2) Volume III provides long-term resource planning considerations, resource options available to meet the planning criteria proposed in Volume I, and Hydro's proposed action plan.

Additionally, a Summary Document ("Planning for Today, Tomorrow, and the Future") is included to highlight, in brief, the key considerations of the 2022 Update. The "Near-Term Reliability Report" (Volume II), which provides an in-depth view of near-term resource adequacy, is not included in this 2022 Update. The "Near-Term Reliability Report" will be filed on November 15, 2022.

2022 Reliability and Resource Adequacy

Hydro has undertaken a planning process to inform the 2022 Update and supporting recommendations. Hydro has conducted its analysis consistent with best practices observed across the industry while attempting to manage significant uncertainty. Like many utilities, Hydro must develop strategies to enable the decarbonization of generation assets and address societal decarbonizing impacts on load requirements.

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[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019.
[3] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021) and "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[4] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022.

The focus of the 2022 Update was to understand annual capacity and energy shortfalls based on a range of scenarios. The analysis and recommendations put forward in the 2022 Update use current assumptions to provide incremental solutions that will be updated annually. The criticality of the ongoing assessment of LIL reliability, the future requirements of the Holyrood TGS and the Hardwoods Gas Turbine, and the potential generation expansion at the Bay d'Espoir Hydroelectric Generating Facility enclosed in the 2022 Update are outlined herein.

Assessing LIL Reliability

The reliability of the LIL is a crucial driver for the reliability of the Island Interconnected System. Since the 2018 Filing and 2019 Update, the LIL has had reliability challenges as a result of structural and software issues. In consideration of this, in early 2020, Hydro commissioned Haldar & Associates Inc. ("Haldar & Associates") to assess the structural reliability of the LIL considering the climatological conditions that could potentially result in an extended bipole outage. Taking into account the risk of unavailability, combined with the assessments completed by Halder & Associates[5] and the information provided in the "Emergency Response and Restoration Plan,"[6] three separate analyses were performed to assess the impact of LIL reliability on the Newfoundland and Labrador Interconnected System.

The analyses considered the potential ranges for the frequency and duration of outages and revealed that due to load growth combined with existing thermal asset retirements, new on-Island capacity will be required in the forecast period to meet the reliability planning criteria if thermal assets are retired as planned. **Given the uncertainty surrounding many long-term planning parameters, Hydro is recommending a phased approach to generation expansion. Subsequent incremental long-term planning decisions regarding expansion will be made as additional information materializes over the coming months and years regarding pending load growth and LIL reliability.**

[5] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021) and "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[6] The "Labrador-Island Link Overhead Transmission Line Emergency Response Plan – Winter 2020-2021," Nalcor Energy – Power Supply, December 15, 2021 was filed as Attachment 1 to the "Near-Term Reliability Report," Newfoundland and Labrador Hydro, May 15, 2020. An update, "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021, was filed as Attachment 2 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.

Assessing the Future of the Holyrood TGS and the Hardwoods Gas Turbine

In late 2020, Hydro advised the Board of Commissioners of Public Utilities ("Board") of its intention to undertake an assessment to determine the potential long-term viability of the Holyrood TGS as a backup facility in the event of a LIL outage. Hydro engaged Hatch Ltd ("Hatch") to conduct the assessment, which concluded in early 2022. Hydro provided Hatch's assessment in its filing to the Board on March 31, 2022.[7] Through this assessment, Hatch concluded that the Holyrood TGS presents a technically viable option under various recall scenarios through 2030.

In assessing the future of the Holyrood TGS, Hydro considered Hatch's assessment, supplemented with the federal government's requirement to achieve net-zero emissions in the electricity sector by 2035. As part of this submission, Hydro also performed a reliability analysis of historical plant data and confirmed that the units demonstrate poor reliability during start-up. As such, Hydro has determined that the Holyrood TGS is not an appropriate long-term, standby option. However, Hydro has established the need for backup generation to support the LIL in the medium term until new sources of generation are available. To that end, **Hydro is recommending continued investment in both the Holyrood TGS and the Hardwoods Gas Turbine to ensure reliable operation in support of the Island Interconnected System in the event of a LIL outage. This will be an interim solution for a "Bridging Period," during which Hydro will seek to develop long-term sources of supply. The units at the Holyrood TGS and the Hardwoods Gas Turbine shall remain available until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. During this period, Hydro will make every effort to minimize the operation of these units.**

Requirement for Expanded Capacity at the Bay d'Espoir Hydroelectric Generating Facility

To meet the reliability criteria proposed and assuming Holyrood TGS and Hardwoods are retired, Hydro is proposing to take an incremental step forward by adding a new capacity asset that expands the existing Bay d'Espoir Hydroelectric Generating Facility with the addition of Unit 8. This asset will serve as a long-term backup facility and support forecasted load growth[8]. Previous analyses have repeatedly identified Bay d'Espoir Unit 8 as a preferred, least-cost, renewable, resource expansion option at an existing site. Unit 8 will have a capacity of 154 MW, which will help to alleviate the system's capacity

[7] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022, atts. 1, 2, and 3.
[8] Hydro's base case load forecast for the Newfoundland and Labrador Interconnected System is expected to increase by 120 MW over the next decade.

constraint, and will be used for base load generation. The capacity and operational flexibility that Bay d'Espoir Unit 8 provides could be used to support intermittent renewable generation in the future, such as wind generation.

Recognizing that the time from recommendation to eventual commissioning of a new resource (such as Bay d'Espoir Unit 8) could potentially take eight years, the need to proceed with the integration of incremental generation is required. Hydro must also consider the current LIL reliability analysis and plan for the potential of an extended loss of the LIL**. Hydro is therefore recommending to proceed with the development of an application for new supply, with the primary consideration being given to expansion at the Bay d'Espoir Hydroelectric Generating Facility; specifically, the addition of Unit 8, with a capacity of 154 MW.**

Following the 2022 Update, Hydro will continue to work with the Board to review the proposed supply source, assess the alternatives, and ensure the least-cost resource option, while considering the proposed federal Clean Energy Standard[9] requirements, is put forward.

Future Considerations

Climate change is driving the demand for clean energy in consideration of targets to achieve net-zero emissions in the electricity sector by 2035. For context, Electricity Canada has specified that an additional 121 TWh of new supply is needed to decarbonize nationally, based solely on existing demand requirements. [10] This would be equivalent to about 4 times the output of Churchill Falls or approximately 25 times the output of the Muskrat Falls Hydroelectric Generating Facility. It is further noted by Electricity Canada that the decarbonization of other sectors will result in an increase in actual electricity demand by a factor of two or three. As such, electricity system planning processes must evolve to meet these demands. All Canadian utilities, including Hydro, are working to navigate the uncertainty and plan system additions to affect the government policy expectations on climate change.

There remains a high level of uncertainty regarding several key considerations that directly impact the 2022 Update. More than ever, resource planning is a continuous process that must respond to an ever-

[9] "Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035," Environment and Climate Change Canada, March 15, 2022, <https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html>

[10] Electricity Canada, "Accelerate Net Zero – State of the Canadian Electricity Industry 2022," Electricity Canada, February 28, 2022, <https://issuu.com/canadianelectricityassociation/docs/soti_2022_highrez?fr=sOGY4NTE1ODE1MTU>

changing energy landscape of customer requirements, weather uncertainties, grid reliability, and evolving provincial environmental priorities. The intent of the 2022 Update is to ensure transparency in Hydro's resource planning decision-making. As new information becomes available that affects and changes assumptions, these assumptions will be refined and incorporated into subsequent filings. However, given the evidence presented in the 2022 Update, there is a definitive requirement to expand system capacity; as such, Hydro proposes advancing the development of Bay d'Espoir Unit 8. As additional information becomes available, decisions relating to further resource additions can be made in consideration of the rate impacts of new loads arising from climate change targets and opportunities.

Improved clarity is expected during 2023 and subsequent years on considerations including:

- The potential for major load growth on the Labrador Interconnected System, as is evidenced through the ongoing *Network Additions Policy* process;
- The potential for additional load growth on the Island Interconnected System due to electrification of the residential sector, electrification of industrial processes, new industrial growth, new industry tied to global climate change actions (such as hydrogen production), and electric vehicle adoption;
- The grid implications of wind integration into the existing system, which is likely to have a material impact on system operations and future resource additions;
- The proposed Clean Electricity Standard, which has brought into question resource options that would traditionally have been recommended but are now uncertain as future resource options (i.e., fossil fuel-burning combustion turbines); and
- The reliability of the LIL post-commissioning. Hydro is planning for how the electrical system may respond to a number of LIL failure modes. The operation of the LIL in its final commission is required to understand its performance and reliability metrics.

Given the significant degree of uncertainty, it is not possible, nor appropriate, to develop an expansion plan or rate impact analysis that encompasses the widely varying potential longer-term outcomes. Hydro's 2022 Update includes recommendations that will advance critical decision inputs in a phased manner. The 2022 Update inputs, along with those uncertainties detailed herein, will continue to be assessed and used in the future planning of the Newfoundland and Labrador Interconnected System. Through this process, further optimization of results will be undertaken, as required, to support incremental decision-making, as Hydro remains committed to working with the Board, its customers, and its stakeholders to help ensure an appropriate balance of cost and reliability for the future provincial electrical system.

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NEWFOUNDLAND & LABRADOR

Reliability and Resource Adequacy Study 2022 Update

Volume I: Study Methodology and Planning Criteria

newfoundland labrador hydro

Contents

List of Attachments

1.0 Introduction

1.1 Newfoundland and Labrador Interconnected System Overview

There are two primary areas or zones of electrical infrastructure in the Newfoundland and Labrador Interconnected System—the Island Interconnected System and the Labrador Interconnected System.

The Island Interconnected System is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula and the 230 kV bulk transmission system extending from Stephenville to St. John's. Currently, the two largest sources of generation on the Island are the Bay d'Espoir Hydroelectric Generating Facility[1] and the Holyrood Thermal Generating Station ("Holyrood TGS").[2] The Island Interconnected System is interconnected to the Labrador Interconnected System via the Labrador-Island Link ("LIL"), a 900 MW HVdc[3] transmission line designed to deliver power from the Muskrat Falls Hydroelectric Generating Facility in Labrador to the Soldiers Pond Terminal Station on the Avalon Peninsula. The Island Interconnected System also connects to the North American Grid via the Maritime Link.[4]

The Labrador Interconnected System is primarily characterized by supply at the Muskrat Falls Hydroelectric Generating Facility and the Churchill Falls Generating Station ("Churchill Falls") as well as transmission to the two major load centres in Labrador East and Labrador West. The supply from Churchill Falls is provided under two contracts—the TwinCo[5] Block and Recapture Energy.[6,7] As noted previously, the Labrador Interconnected System is connected to the Island Interconnected System via the LIL. The Labrador Interconnected System is also connected to the North American Grid via the 735 kV HVac transmission lines from Churchill Falls to Québec.

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[1] A 613 MW hydraulic plant on the south coast of the Island.
[2] A 490 MW oil-fired thermal generating plant located on the Avalon Peninsula.
[3] High-voltage direct current ("HVdc").
[4] The Maritime Link is a 500 MW (+/- 200 kV) HVdc transmission line, as well as a 230 kV high-voltage alternating current ("HVac") transmission line and associated infrastructure, connecting Newfoundland and Labrador to Nova Scotia.
[5] Twin Falls Power Corporation Limited ("TwinCo").
[6] The power referred to as the TwinCo Block of power is a firm 225 MW block of power and energy capable of supplying 1,971 GWh per year for use in Labrador West.
[7] Recapture Energy is a source of 300 MW of capacity at a 90% monthly load factor available at Point A. The amount of Recapture Energy available at the Churchill Falls bus is different from the 300 MW stated at the border due to the difference in location. The original Hydro-Québec 1969 Power Contract has the delivery point for the 300 MW as "the point in Labrador on the transmission lines from the CF(L)Co Plant towards the Province of Québec which is at the height of land, about opposite present Mile 148.8 on the Québec North Shore and Labrador Railway, which is the presumed watershed between the St. Lawrence River and the Churchill River."

Work continues on the integration of the Muskrat Falls Project Assets, which consist of the Labrador Transmission Assets, the Maritime Link, the LIL, and the Muskrat Falls Hydroelectric Generating Facility. Both the Labrador Transmission Assets and the Maritime Link were placed in service in 2018[8] and the Muskrat Falls Hydroelectric Generating Facility was fully commissioned in December 2021. The LIL began delivering electricity to the Island Interconnected System from the Muskrat Falls Hydroelectric Generating Facility in 2021. As of the filing of Newfoundland and Labrador Hydro's ("Hydro") "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update"), the LIL has been successfully tested and operated up to 475 MW.

Figure 1 presents an overview of the Muskrat Falls Project Assets, which will interconnect to form part of the Newfoundland and Labrador Interconnected System.

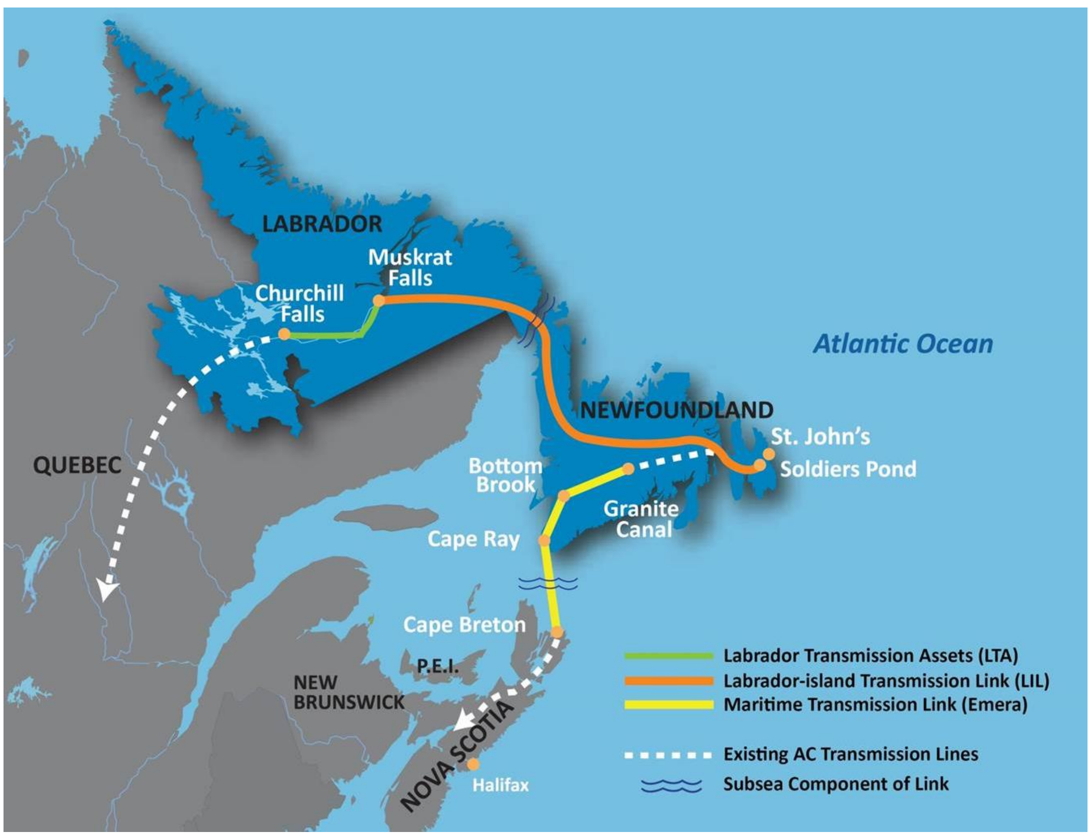

Figure 1: Muskrat Falls Project Assets

[8] Construction of the Labrador Transmission Assets was completed late 2017. Handover of the asset to Hydro occurred in early 2018.

1.2 Hydro's Mandate and Resource Planning

A comprehensive set of results and supporting analysis from Hydro's resource planning process was previously provided to the Board of Commissioners of Public Utilities ("Board") as part of the "Reliability and Resource Adequacy Study" ("2018 Filing").[9] That analysis proposed changes to resource planning criteria stemming from system changes resulting from the interconnection of the Labrador Interconnected System and the Island Interconnected System with the North American Grid. Proposed changes included:

- The migration to planning on a regional and sub-regional basis;[10] and
- The migration to the adoption of the LOLE[11] target of 0.1.[12]

The 2018 Filing was followed by the "Reliability and Resource Adequacy Study – 2019 Update" ("2019 Update"),[13] which provided:

- Additional detail on matters Hydro continued to investigate through 2019;
- Responses to findings and recommendations made by The Liberty Consulting Group ("Liberty") in its review;
- Updates on items identified in the action plan included in Hydro's 2018 Filing; and
- Updated identification of timing by which incremental resources are likely to be required based on the 2019 assessment.

The 2022 Update is filed as a complement to Hydro's 2018 Filing[14] and the 2019 Update. It is intended to provide additional detail on matters Hydro has continued to investigate as well as responses to findings

[9] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[10] Pending the outcome of the *Network Additions Policy – Labrador Interconnected System* process, there may be a requirement to assess the Labrador Interconnected System on a sub-regional basis, due to the potential for growth in load requirements.
[11] Loss of load expectation ("LOLE") is the expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.
[12] In 2018, Hydro intended to migrate to its proposed criteria of 0.1 LOLE when the Muskrat Falls Project has been fully commissioned and deemed reliable and when thermal generation at the Holyrood TGS, the Hardwoods Gas Turbine, and the Stephenville Gas Turbine has been retired.
[13] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019.
[14] As stated in the 2018 Filing, the future reliability of the Island Interconnected System formed part of *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 3(2014), Board of Commissioners of Public Utilities, February 19, 2014, sch. A, p. 1, which ordered an evaluation of the Island Interconnected System adequacy and reliability up to and after the interconnection with the Muskrat Falls Hydroelectric Generating Facility.

and recommendations made by the LIL reliability assessments[15] and the Holyrood TGS assessment.[16] In addition, this filing will include updated timing by which incremental resources are likely to be required. An independent review of Hydro's ongoing efforts to meet reliability and resource adequacy requirements can be found in Attachment 1 of the "Study Methodology and Planning Criteria" filed as part of the 2022 Update.

System planning entails the development and assessment of supply adequacy under various potential future realities. This ensures that both sufficient capacity[17] and energy[18] are available to meet customer and system requirements and determines the appropriate timing of requirements for additional resources. Consistent with Hydro's 2018 Filing and 2019 Update, the 2022 Update analysis focused on the ability to reliably meet customer and system requirements over a ten-year planning horizon, covering the period from 2023 through 2032.[19] Operational requirements, such as operating reserve, have also been evaluated as part of the 2022 Update; Section 3.2.2 provides a more detailed discussion.

As proposed in the 2018 Filing, the intent is to update and file the assessment of resource adequacy annually. The intent of the annual update is to provide the Board and stakeholders with additional information on the analysis conducted throughout the year and revised results that incorporate that analysis. A number of core filings pending submission led to the delay of both the 2020 and 2021 updates. While certain long-term matters could be updated, such items are not likely to result in significant changes to the plan issued as part of the 2019 Update. However, the ongoing matters outlined in Hydro's correspondence to the Board on March 16, 2021[20] could all have a material impact on the plan results. These include the continued assessment of the reliability of the LIL, the assessment to determine the potential long-term viability of the Holyrood TGS, and the implementation of the

[15] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021) and "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "*Reliability and Resource Adequacy Study Review* – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[16] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022.
[17] Firm capacity refers to the amount of generation capacity available for production or transmission expected to be available at the annual peak when the unit is fully operational.
[18] Energy refers to the actual energy guaranteed to be available to meet customer requirements on an annual basis.
[19] Reporting on a ten-year planning horizon is observed in the "2021 Long-Term Reliability Assessment," North American Electric Reliability Corporation, December 2021,
<https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf>
[20] "*Reliability and Resource Adequacy Study Rev*iew – 2021 Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, March 16, 2021.

Network Additions Policy – Labrador Interconnected System ("*Network Addition Policy*").[21] Given the likely material impact of the noted matters on the outcomes of its planning assessments, deferring the filing of the "Study Methodology and Proposed Planning Criteria" (Volume I) and the "Long-Term Resource Plan" (Volume III) was considered the most appropriate decision. Hydro has continued to file its "Near-Term Reliability Report" (Volume II) twice per year.

Given the current evolving nature of the Newfoundland and Labrador Interconnected System and the evolution of system reliability as Hydro continues to work towards fully integrating the Muskrat Falls Hydroelectric Generating Facility, the focus of this filing addresses LIL reliability, the need for on-Island resources, and how existing thermal generation and standby sources can support these requirements in the interim. There remains a high level of uncertainty regarding the potential load growth on the Labrador Interconnected System, due to significant customer requests following the implementation of the *Network Additions Policy*, and on the Island Interconnected System, due to electrification and electric vehicle ("EV") adoption and the possibility of new mines as well as wind and hydrogen projects. The grid implications of wind integration into the existing system have not been included in this analysis, as the Wind Development Process[22] is ongoing. However, Hydro recognizes wind integration is likely to have a material impact on system operations and future resource additions.

Furthermore, the proposed Clean Electricity Standard[23] has brought into question resource options that would traditionally have been recommended but are now uncertain as a future resource option (e.g., fossil fuel-burning combustion turbines). Therefore, the 2022 Update does not include an expansion plan that contemplates all these uncertainties; rather, it identifies capacity shortfalls in the year they are forecast to occur based on a range of possibilities. Hydro is committed to assessing the impact of the Wind Development Process, the outcome of the *Network Additions Policy* process, other pending system growth possibilities, and further review of the Clean Electricity Standard and its impact

[21] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System,* <https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf>

[22] The Wind Development Process is an ongoing process that is being led by the Government of Newfoundland and Labrador and supported by Hydro to enable wind generation in the province. As part of this process, Hydro is undertaking a third-party study with the goal of determining the amount of wind that can be integrated into Hydro's system, including preliminary interconnection information for future potential self-supply customers.

[23] "Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035," Environment and Climate Change Canada, March 15, 2022, <https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html>

on resource options as part of its "Reliability and Resource Adequacy Study – 2023 Update" ("2023 Update").[24]

Given the high costs associated with resource expansion and ongoing matters that will continue to have a material impact on the resource plan, Hydro recommends proceeding with a decision-based phased approach. Hydro intends to ensure that it provides stakeholders with a fulsome view of the impact of these matters on provincial reliability to support informed opinions and decision-making based on the best information available.

From a capacity perspective, in accordance with industry practice, both probabilistic and deterministic assessments of adequacy were completed. Probabilistic assessments use statistical analyses of system performance and projected supply availability (e.g., forced outage rate) and simulate system behaviour to determine the resultant forecast system reliability. This indicates the likelihood that all demand will be served. A deterministic analysis evaluates the contribution of individual system elements to overall system reliability. This provides the ability to test system resiliency in consideration of different contingencies or outage events. The use of differing but complementary methods offers a robust analysis of system adequacy. Hydro will continue to assess supply adequacy on the basis of both probabilistic and deterministic supply adequacy criteria.

From an energy perspective, Hydro completed an assessment of its ability to meet firm energy requirements in consideration of firm hydraulic energy sequences.[25]

[24] Hydro intends to file its 2023 Update in the fall of 2023.
[25] Minimum storage targets are developed annually to provide guidance in the reliable operation of Hydro's major reservoirs: Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage target is designed to show the minimum level of aggregate storage required such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, Hydro's load can still be met through the use of the available hydraulic storage, maximum generation at the Holyrood TGS, and imports. Hydro's long-term critical dry sequence is defined as January 1959 to March 1962 (39 months). Other dry periods are also examined during the derivation to ensure that no other shorter-term historic dry sequence could result in insufficient storage.

2.0 Overview of the Resource Planning Process

Figure 2 is a flowchart that provides a visual representation of Hydro's resource planning process. A comprehensive overview of the resource planning process can be found in the 2018 Filing.[26]

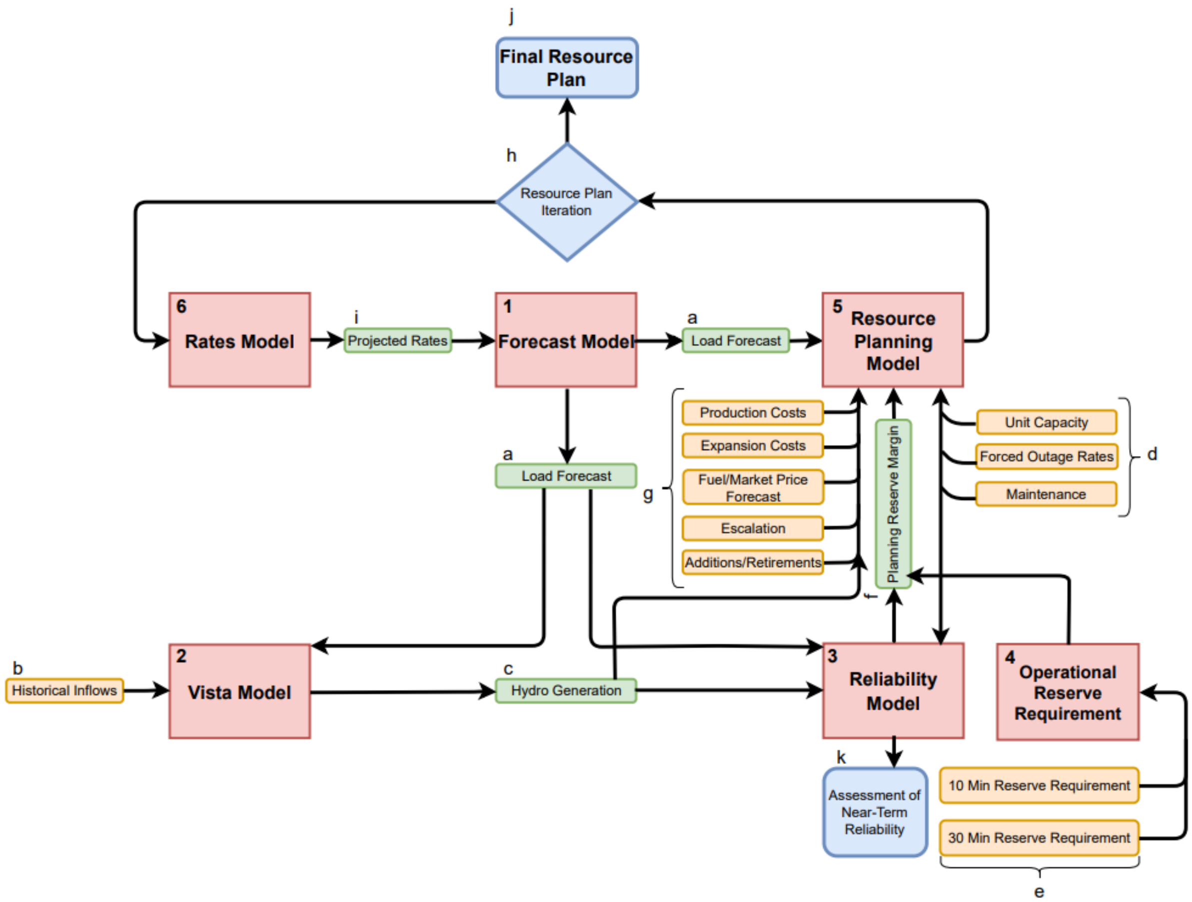

Figure 2: Resource Planning Process Flowchart

2.1 Temporary Modification Required to the Planning Process

The process outlined in Figure 2 details Hydro's traditional approach to resource planning. The impact of rates following the in-service of the Muskrat Falls Project Assets required a modified approach in both the 2018 Filing and the 2019 Update to support the development of additional information pertinent to the *Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs*

[26] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 1.3.

proceeding.[27] The mitigated rate that formed the basis of the rate included in the load forecast is the target mitigated rate that was announced publicly by the Government of Newfoundland and Labrador.[28] The final rate mitigation plan is required for there to be certainty on the actual mitigated rate.

All inputs in the resource planning process flowchart were completed for the 2022 Update except for Step "h" (the resource plan iteration that flows through the rates model), the forecast model, and the resource-planning model until the iterative approach defines an appropriate rate. Historically, if generation expansion projects are determined to be required for a particular load forecast, the Island Interconnected System utility forecast is updated to reflect a domestic electricity price forecast that will have an estimate of rate impacts as a result of expansion builds. However, due to ongoing matters impacting system planning, as mentioned in Section 1.2, the resource plan was not modelled in the long-term financial model in an iterative approach to determine the precise impact of required investment on customer rates. Rather, an estimated rate impact placeholder for generation expansion builds was utilized to assess the impact on the Island Interconnected System. This estimated rate impact placeholder was included as an addition to the mitigated rate. As Hydro continues to work with stakeholders and gain additional information to inform the analysis, an iterative assessment of rates and expansion plans will be performed. Hydro anticipates being able to complete such an assessment as part of the 2023 Update.

3.0 Proposed Planning Criteria

Resource planning activities are generally focused on satisfying an adopted loss of load criteria while ensuring sufficient resources to meet operational reserves. Loss of load metrics provide a probabilistic assessment of system reliability. This helps to quantify the likelihood that a utility will not be able to meet its load requirements at a point in time, considering numerous potential operating scenarios that

[27] "*Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs*," Newfoundland and Labrador Board of Commissioners of Public Utilities, Media Release, October 16, 2018, <http://pub.nl.ca/applications/2018ratemitigation/notices/Media%20Release%20-%20Rate%20Mitigation%20Options%20and%20Impacts%20-%20FINAL%20-%202018-10-16.pdf>

[28] The Government of Newfoundland and Labrador's rate mitigation target of 14.7 cents per kWh, escalating at 2.25% per year, as referenced in the "Technical Briefing Rate Mitigation," Government of Newfoundland and Labrador, July 28, 2021 filed as part of the "Items Impacting the Delay of Hydro's Next General Rate Application – Further Update," Newfoundland and Labrador Hydro, August 27, 2021.

can occur.[29] In other words, loss of load metrics evaluate the instances in which system load exceeds the available generating capability.[30]

3.1 Summary of Criteria Review

3.1.1 Existing Planning Criteria

System supply investment needs have been based on previously established resource planning criteria, detailed as follows:

- **Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.
- **Energy:** The Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

Additionally, operational reserves of no less than 240 MW on the Island Interconnected System are maintained. This 240 MW reserve margin provides the ability to meet current operational reserve requirements.[31]

As discussed in the 2018 Filing, the existing criteria will continue to be applied until full integration and reliable operation of the Muskrat Falls Project Assets.[32] With the evolving nature of the Newfoundland and Labrador Interconnected System due to the timing of LIL commissioning, Hydro recognizes there is a need to better understand reliability expectations, the implications for reserve requirements, the resulting supply adequacy, and subsequent economics to meet these criteria.

3.2 Proposed Reliability Criteria

Many utilities throughout Canada and across North America have adopted reliability metrics that follow guidelines established by NERC.[33] Hydro continues to recommend modifications to both the probabilistic and deterministic capacity planning criteria to bring reliability metrics used in the Newfoundland and

[29] Loss of load refers to instances where some system load is not served, firm commitments are not met, or minimum operational reserve limits are violated.
[30] There are four generally accepted types of probabilistic metrics against which system reliability is measured, Loss of Load Probability (“LOLP”); Loss of Load Expectation (“LOLE”); Loss of Load Hours (“LOLH”); and Expected Unserved Energy (“EUE”).
[31] Operationally, the system requires the ability to withstand the loss of the single largest resource (typically the loss of the Holyrood TGS Unit 1 or 2, or Bay d’Espoir Unit 7) while maintaining an additional regulating reserve of 70 MW.
[32] “Reliability and Resource Adequacy Study,” Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 3.1.
[33] North American Electric Reliability Corporation (“NERC”).

Labrador Interconnected System more in line with those commonly used across North America; recognizing, however, that economically meeting these criteria is dependent on the reliable integration of the Muskrat Falls Project Assets.

Detailed information on the analysis conducted and the development of Hydro's proposed criteria can be found in the 2018 Filing.[34] A summary of the proposed reliability criteria for the Newfoundland and Labrador Interconnected System follows. Summaries of detail provided in the 2018 Filing are provided for sections with inputs and assumptions that have not had a material change. Sections that have been expanded on since the 2018 Filing and 2019 Update are discussed in detail.

3.2.1 Probabilistic Capacity Planning Criterion

Hydro has proposed that both the Newfoundland and Labrador Interconnected System (region) and the Island Interconnected System (sub-region) should each have sufficient generating capacity to meet the reliability planning criteria of LOLE of no more than one day in ten years (i.e., 0.1 LOLE) once the Muskrat Falls Project Assets are fully integrated and proven reliable, and the Holyrood TGS, Hardwoods Gas Turbine, and Stephenville Gas Turbine are retired.

Hydro maintains that the adoption of the LOLE metric with the target of LOLE ≤ 0.1 increases planned system reliability from that which would be planned based on the pre-existing probabilistic criterion of LOLH ≤ 2.8, necessitating a larger level of required reserves and a corresponding increase in reliability, albeit at a higher cost.

Hydro has implemented a minimum regulating reserve[35] in its Reliability Model. In the 2019 Update, it was determined that the amount of such regulating reserve required to be held on the system differs based on whether the LIL is in service, due to the LIL frequency control capability. When the LIL is in service, the system requires a lower minimum regulating reserve, as the LIL can provide frequency regulation. In the 2019 Update, Hydro preliminarily defined a minimum regulating reserve of 35 MW for when the LIL was in service while maintaining a minimum reserve of 70 MW within the Island Interconnected System when the LIL was out of service to provide acceptable frequency regulation.

[34] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I.
[35] Unlike other reserves that are used in response to contingencies (i.e., operating reserves), regulating reserves are used throughout an operating hour to maintain system frequency in response to fluctuations in loads and in output from variable generation resources.

Given the continued uncertainty pertaining to LIL reliability, Hydro believes it to be prudent to maintain a minimum regulating reserve of 70 MW within the Island Interconnected System, whether or not the LIL is in service. This is subject to further review once operational experience is gained with the LIL.

3.2.2 Operational Reserve Requirements

The Maritimes Assessment Area[36] is included as one of the eight regions governed by the Northeast Power Coordinating Council ("NPCC").[37] The NPCC requirements state that compliant utilities will ensure that:

> "Each Balancing Authority shall have *ten-minute reserve* available to it that is at least equal to its *first contingency loss* . . . Each Balancing Authority shall have *thirty-minute reserve* available to it that is at least equal to one-half its *second contingency loss*. [emphasis added]"[38,39]

In the Newfoundland and Labrador Interconnected System, Hydro considers the first contingency loss to be the loss of a generating unit at the Muskrat Falls Hydroelectric Generating Facility and the second contingency loss to be the loss of a second unit at Muskrat Falls Hydroelectric Generating Facility, once the LIL is considered fully operational. As such, Hydro will plan for the availability of the following operational reserves for the Newfoundland and Labrador Interconnected System to align with these criteria.[40,41]

- **10-Minute Reserves:** Hydro shall have a 10-minute reserve available to it at least equal to 197.5 MW to cover its first contingency loss, where the first contingency loss is the loss of a

[36] The Maritimes Assessment Area is comprised of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system.
[37] NPCC is a regional entity division that operates under a delegation agreement with the NERC.
[38] The Balancing Authority is defined by NERC as "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. Please refer to "Definitions used in the Rules Of Procedure," North American Electric Reliability Corporation, May 19, 2022, app. 2, p. 2, <https://www.nerc.com/AboutNERC/RulesOfProcedure/ROP_Appendix%202_20220519.pdf >
[39] "Regional Reliability Reference Directory # 5 Reserve," Northeast Power Coordinating Council, rev. September 27, 2019 (originally issued December 2, 2010, secs. 5.R1 and 5.R2, <https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-5-reserve-20200426.pdf>
[40] For additional information about the winter firm plant output of the Muskrat Falls Hydroelectric Generating Facility, please refer to "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 4.2.2.3.
[41] This is based on the per unit contribution to the firm plant output of the Muskrat Falls Hydroelectric Generating Facility (790 MW).

single unit (of the four in operation) at the Muskrat Falls Hydroelectric Generating Facility at winter firm plant output of 790 MW.

- **30-Minute Reserves:** Hydro shall have a 30-minute reserve available to it at least equal to 99 MW to cover one-half the magnitude of its second contingency loss (0.5 × 197.5 MW), where the second contingency loss is the loss of a second unit at the Muskrat Falls Hydroelectric Generating Facility at winter firm plant output of 790 MW.

In total, operational reserves of at least 296.5 MW will be maintained for the Newfoundland and Labrador Interconnected System.[42]

To provide a fulsome view of the impacts of LIL reliability on the Island Interconnected System, an additional case analysis was completed that considers the bipole loss of the LIL as a single contingency (i.e., energy-only line). Additional information on the reliability results considering the loss of the LIL bipole as a single contingency event, including implications to the 10-minute and 30-minute operational reserve requirement, is provided in Section 5.6 of the "Long-Term Resource Plan" included as part of the 2022 Update.

3.2.3 Energy Criterion

A review of the system's energy capability and forecasted load requirements has resulted in the extension of the existing energy planning criteria to cover the entire Newfoundland and Labrador Interconnected System, as follows.

- **Energy:** The Newfoundland and Labrador Interconnected System should have sufficient generating capability to supply all of its firm energy[43] requirements with firm system capability.

This analysis was completed for the 2018 Filing and the 2019 Update. At that time, the analysis showed no energy deficiencies were expected throughout the study period. However, with the increasing potential for industrial load growth on the Labrador Interconnected System and increased electrification and EV growth on the Island Interconnected System, the Newfoundland and Labrador Interconnected

[42] The addition of the 10-minute reserve requirement (197.5 MW) and the 30-minute reserve requirement (99 MW) yields a reserve requirement of 296.5 MW.
[43] Firm energy refers to the actual energy guaranteed to be available to meet customer requirements on an annual basis.

System may be at risk of violating this criterion by 2030 in the higher load growth scenarios. The results are presented in Section 6.0 of the "Long-Term Resource Plan" included as part of the 2022 Update.

4.0 Study Methodology

4.1 Modelling Assumptions

Figure 3 is a representation of the Newfoundland and Labrador Interconnected System. It is a simplified display of how each region is electrically connected within the provincial zone and to the external markets in Québec and Nova Scotia, with arrows indicating the flow of energy.

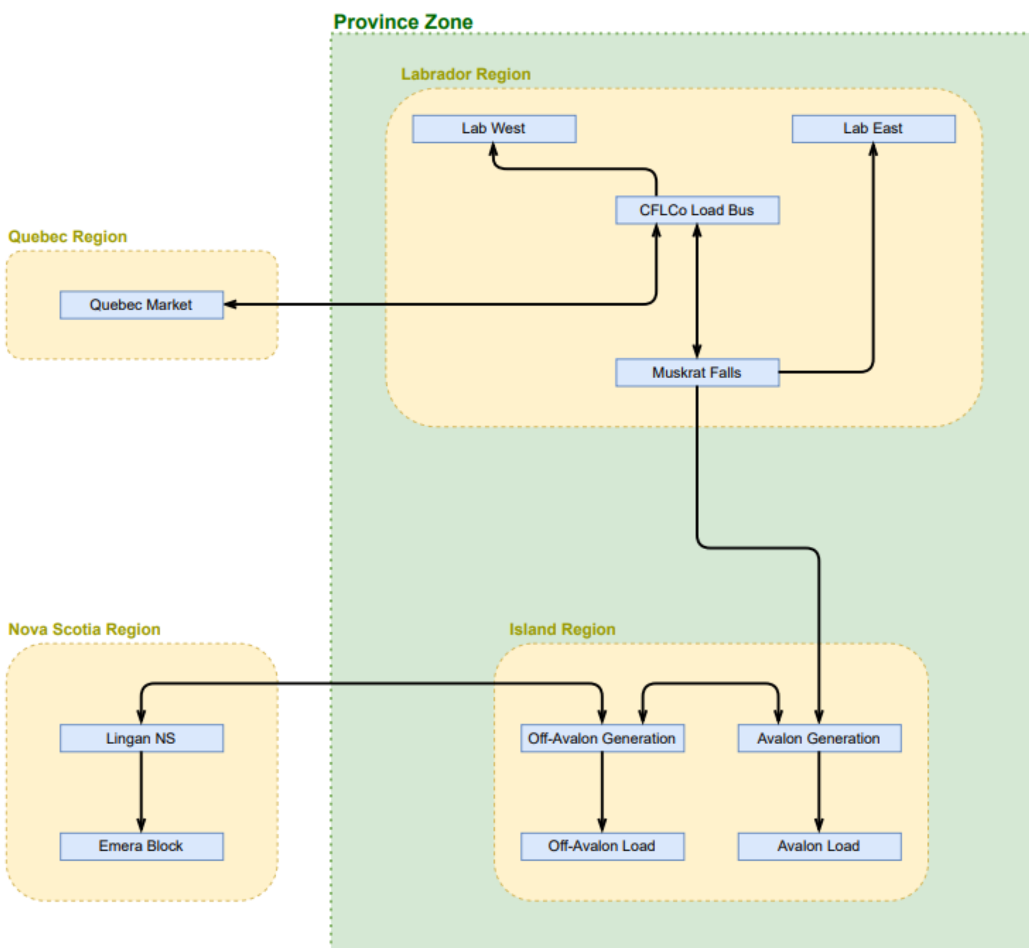

Figure 3: Newfoundland and Labrador Model Topography

4.2 Key Reliability Model Inputs

The methodology surrounding the development of each component of the Newfoundland and Labrador Interconnected System in the Reliability Model; including the load forecast, capacity by asset class, transmission, and the energy market; are all discussed extensively in the 2018 Filing[44] and updated in the 2019 Update.[45] Summaries of detail provided in the 2018 Filing are provided for sections with inputs and assumptions that have not had a material change in methodology. Sections that have been expanded on since the 2018 Filing and 2019 Update are discussed in detail.

- **Transmission System:** Update to system loss equations, transmission constraints, and LIL assumptions;
- **Load Forecast Modelling:** Update to the Newfoundland and Labrador Interconnected System coincidence factors and capacity assistance and curtailable load;
- **Capacity by Asset Class:** Update to reflect Newfoundland Power Inc. ("Newfoundland Power") retirements;
- **Variable Energy Resources:** No change in methodology from the 2019 Update;
- **Capacity Transfers:** Imports and Exports—no change in methodology from the 2019 Update; and
- **Emergency Operating Procedures:** No change in methodology from the 2019 Update.

4.2.1 Transmission System

Hydro's Reliability Model includes a simplified representation of the transmission system to ensure the system can deliver electricity to meet customer requirements and that all relevant constraints are appropriately considered as part of the resource planning process. Hydro's Reliability Model separates the Newfoundland and Labrador Interconnected System into two regions linked by transmission—the Island Interconnected System region and the Labrador Interconnected System region—with the LIL connecting the two. These regions are further divided into sub-regions (e.g., Avalon, Off-Avalon, Lab West, Lab East) linked by the transmission network for the purposes of calculating losses. There are also

[44] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 4.
[45] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, sec. 5.

two external regions modelled, representing the two connections to external markets via Québec and Nova Scotia. The transfer capability of each transmission line is included in the Reliability Model.

As part of the 2022 Update, system loss equations were revised based on recent analyses. For further details on transmission modelling, please refer to the 2018 Filing.[46]

A transmission constraint was revised for the Island Interconnected System and updated in the Reliability Model. From that analysis, it was determined that if the LIL experienced a bipole (i.e., total) outage, the eastward power flows from the Bay d'Espoir Hydroelectric Generating Facility would be limited to a maximum of approximately 750 MW.[47] In the 2018 Filing, the eastward power flows from the Bay d'Espoir Hydroelectric Generating Facility were limited to a maximum of approximately 650 MW.

The reason for the change was the adoption of emergency planning criteria by Hydro. These criteria were adopted in consideration of power flow constraints that limited power flow to the Avalon Peninsula from the Bay d'Espoir Hydroelectric Generating Facility. Specifically, under normal operations, power flows are limited to 650 MW to ensure that there is no risk of instability in the event of a three-phase fault at the Bay d'Espoir Terminal Station. Given the low probability of a three-phase fault, it was determined that this constraint could be lifted in the event of an emergency outage of the LIL bipole. As a result, power flows up to 750 MW may be permitted under the emergency criteria.

LIL Reliability

With the addition of the Muskrat Falls Hydroelectric Generating Facility, a large portion of the generation serving the Island load is in Labrador. Therefore, the reliability of the LIL continues to be a key driver of Newfoundland and Labrador Interconnected System reliability. Since the 2018 Filing and 2019 Update, the LIL has had periods of unavailability due to structural and software issues. In consideration of this unavailability, combined with the assessments completed by Haldar & Associates

[46] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 4.2.5.
[47] Further Avalon transmission constraints will be assessed during the next stage of the study.

Inc. ("Haldar & Associates")[48] and the information provided in the Emergency Response and Restoration Plan,[49] three separate analyses were performed to assess the impact of LIL reliability.

Absent any long-term operational experience with the LIL post-commissioning, Hydro recognizes that the previously-anticipated bipole forced outage rate of 0.0114% is no longer appropriate.[50,51] Until the LIL is fully commissioned with multiple years of operational experience to better inform the selection of a bipole forced outage rate, the LIL capacity and bipole forced outage rate will be addressed with a range of upper and lower limits. This range of values can then be used to assess the reserve margin effects that the LIL has on system reliability and overall system planning.[52] As LIL performance statistics become available in the coming years, the forced outage rate range can be narrowed in future filings.

A similar approach was taken with the LIL capacities. As the LIL is not yet fully commissioned to its rated 900 MW capacity but has currently been tested up to 475 MW, a range of capacities was also considered.

As such, the reliability of the LIL was modelled in three ways for the 2022 Update.

1) Reliability of the LIL

This method models the LIL reliability probabilistically using a forced outage rate range of 1% to 10% for the bipole (full link), in addition to a range of LIL capacities.

[48] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021) and "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[49] The "Labrador-Island Link Overhead Transmission Line Emergency Response Plan – Winter 2020-2021," Nalcor Energy - Power Supply was filed as Attachment 1 to the "Near-Term Reliability Report," Newfoundland and Labrador Hydro, May 15, 2020. An update, "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021, was filed as Attachment 2 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[50] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, att. 7 provided a technical note that discussed the robust nature of the design and construction of the LIL, the anticipated asset reliability, and the anticipated required maintenance.
[51] The monopole forced outage rate is not a driver for LIL reliability given the ability for each pole to be loaded to 1.5 times its rated capacity on a continuous basis (675 MW). Each pole can also be temporarily loaded to twice its rated capacity for ten minutes (900 MW), allowing for no interruption of supply for momentary pole trips.
[52] Attachment 2 to the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update provides considerations for HVdc outage and unavailability rates.

Table 1: LIL Capacity and Bipole Forced Outage Rates[53]

LIL Capacity (MW)	LIL FOR[54] (%)
900	1%
675	5%
675	10%
475	10%

2) Extended Outage of the LIL

This method models a probabilistic scenario where the LIL is unavailable for six weeks to quantify the resultant system reliability and identify the costs associated with providing incremental generation to reduce LOLP.

In 2019, Hydro undertook an exercise to determine the estimated time to restore power based on the location of the failure. At the time, it was determined that restoration could take up to seven weeks, depending on the circumstances of the failure. An additional analysis was undertaken in 2021 by a third party to assess the timelines for power restoration for seven discrete scenarios. This analysis resulted in a similar estimated restoration period of three to six weeks, depending on the scenario, including logistics and line location.[55] To account for this possibility, Hydro updated the extended LIL outage analysis from three weeks, as reported in the 2019 Update, to six weeks to align with the third-party assessment and Hydro's own determination of the estimated time to restore power.

3) LIL as an Energy-Only Line

This method models a scenario where the loss of the LIL is considered the first contingency[56] (i.e., energy-only line), rather than the loss of a single unit at the Muskrat Falls Hydroelectric Generating Facility, as is currently assumed.

[53] For reference, a bipole forced outage rate of 1% equates to approximately 3.5 days per year when the LIL is unavailable; a bipole forced outage rate of 5% represents approximately 18.25 days per year; a bipole forced outage rate of 10% represents approximately 36.5 days per year of unavailability.
[54] Forced outage rate ("FOR").
[55] "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[56] The first contingency is the unexpected failure or outage of a system's largest component, such as a generator or transmission line.

To provide a fulsome view of the impacts the LIL has on the reliability of the Island Interconnected System, an additional reliability case analysis was completed that considers the bipole loss of the LIL as the first contingency. As stated in the 2018 Filing and the 2019 Update, for the Newfoundland and Labrador Interconnected System, Hydro considered the first contingency loss to be the loss of a generating unit at the Muskrat Falls Hydroelectric Generating Facility and the second contingency to be the loss of a second unit at the Muskrat Falls Hydroelectric Generating Facility.[57] While this approach is reasonable on a provincial basis, it is subject to continued concerns over the consequences of a bipole LIL outage on the Island Interconnected System. If the largest contingency were determined to be the bipole outage, operational reserves would need to be significantly increased to support 10- and 30-minute reserves, as previously defined in Section 3.2.2. Additional information on the reliability results considering the loss of the bipole as the first contingency event, including implications to the 10- and 30-minute operational reserve requirement is provided in Section 5.6 of the "Long-Term Resource Plan" for the 2022 Update.

The reliability of the LIL analysis (Item 1) was completed using the Reliability Model, the results of which can be found in Section 5.0. Both the extended outage of the LIL (Item 2) and loss of the LIL as the first contingency (Item 3) analyses can be found in Sections 5.5 and 5.6 of the "Long-Term Resource Plan" included as part of the 2022 Update.

4.2.2 Load Forecast

The load forecast is a key input to the resource planning process that projects electric power demand and energy requirements through future periods. The Newfoundland and Labrador Interconnected System load forecast is segmented by the Island Interconnected System and Labrador Interconnected System and rural systems, as well as by utility load (i.e., Domestic and General Service loads of Newfoundland Power and Hydro) and Industrial load.[58] The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. The load forecasts for the Island Interconnected System and Labrador Interconnected System were prepared during the spring and summer of 2022.

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[57] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 3.3.1.2 and "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, sec. 4.2.2.
[58] Hydro has five Industrial customers on the Island and two Industrial customers in Labrador.

Utility load requirements are primarily dependent on the level of electrification and EV penetration during the period. Due to the level of uncertainty of this penetration, a range of potential forecast scenarios was considered, rather than a single forecast. This allows for evaluation of the sensitivity of results to differing economic conditions and load growth opportunities. For the 2022 Update, a range of forecasts was developed independently for the Island and Labrador. The combination of those forecasts resulted in the evaluation of four discrete load scenarios. A summary of each scenario follows.

Considered Potential Island Load Scenarios:

- **Case I: Base:** Representative of the base provincial economic forecast, a moderate growth forecast for EV adoption, and an electricity price forecast that has a built-in estimate of the potential rate impact due to generation additions required for reliability.[59,60]
- **Case II: High Growth:** Representative of a high growth provincial economic forecast and high growth forecasts for EV adoption and building electrification.

Considered Potential Labrador Load Scenarios:

- **Case I: Base:** Reflects Hydro's Rural Load Forecast Spring 2022, which includes existing data centre requirements and existing industrial loads.
- **Case II: High Growth:** Developed to include requests for service submitted to Hydro as part of the *Network Additions Policy*.[61] Specifically, some of the additional load requirements in Case II: High Growth are for the existing Industrial customers, such as the Department of National

[59] The forecast also takes into account the Government of Newfoundland and Labrador's current plan for electrification of their own buildings.
[60] The underlying electricity rate aligns with the Government of Newfoundland and Labrador's rate mitigation target of 14.7 cents per kWh, escalating at 2.25% per year, as referenced in the "Technical Briefing Rate Mitigation," Government of Newfoundland and Labrador, July 28, 2021 filed as part of the "Items Impacting the Delay of Hydro's Next General Rate Application – Further Update," Newfoundland and Labrador Hydro, August 27, 2021. An estimated rate impact of generation expansion builds was utilized to asses the impact on the Island Interconnected System load forecast. This is considered a high-level estimate of what the rate impact potential could be based on an estimate of the cost of builds over the ten-year forecast period.
[61] In *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 7(2021), Board of Commissioners of Public Utilities, March 17, 2020, the Board approved a *Network Additions Policy* for Labrador that laid out the rules for cost allocation to customers when transmission investments are triggered by customer load on the Labrador Interconnected System. Such a policy is standard practice in utilities and protects all customers from unfair cost allocation. "Labrador Interconnected System Network Additions Policy – Summary Report," Newfoundland and Labrador Hydro, December 14, 2018, <http://www.pub.nf.ca/applications/NLH2018NetworkAdditions/policy/From%20NLH%20-%20Labrador%20Interconnected%20System%20Network%20Additions%20Policy%20-%20Summary%20Report%20-%202018-12-14.PDF>

Defence at 5 Wing Goose Bay, and other firm requirements from non-data centre customers, totalling 330 MW.

Service requests from the *Network Additions Policy* currently total 1,300 MW, exceeding the amount noted in Case II: High Growth, and are further explained in Section 4.4 of the "Long-Term Resource Plan" included as part of the 2022 Update. As there remains a high level of uncertainty about the total service requests in Labrador, only requests from existing Industrial customers have been included in Case II: High Growth. As the *Network Additions Policy* process advances, Hydro will continue to assess the level of service requests to include in the load forecast or to assess sensitivities to the Case I: Base, as appropriate. Early discussions with various proponents interested in advancing new industries, such as hydrogen production, that would have a major impact on the system planning conclusions are not included in either Case I: Base or Case II: High Growth for the Island due to the unconfirmed nature of their needs. Should projects make a formal and final request for service that impacts the system planning forecast, Hydro will update the forecast. Significant loads not current in Case I: Base or Case II: High Growth either on the Island or in Labrador will have a material effect on the conclusions in the 2022 Update, including the timing and size of new resources required. More information on the development of the load forecast is contained in Section 4.0 of the "Long-Term Resource Plan" included as part of the 2022 Update.

Newfoundland and Labrador Interconnected System Coincidence

The assessed coincidence factors[62] in 2022 for the Newfoundland and Labrador Interconnected System peak have been estimated at 99.6% for the Island Interconnected System peak demand and 95.4% for the Labrador Interconnected System peak demand.[63] This means that at the time of the forecast Newfoundland and Labrador Interconnected System Peak, the Island Interconnected System is forecast to be 99.6% of its forecast peak demand and the Labrador Interconnected System is at 95.4% of its forecast peak demand. The coincidence or simultaneous occurrence of the Island Interconnected System and the Labrador Interconnected System demand is what drives the overall system peak.

[62] The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System, it provides a measure of the relative contribution of the Island Interconnected System and the Labrador Interconnected System peaks to the combined Newfoundland and Labrador Interconnected System Peak.

[63] The assessed coincidence factors in 2018 for the Newfoundland and Labrador Interconnected System peak were estimated to be 99.2% for the Island Interconnected System peak demand and 95.3% for the Labrador Interconnected System peak demand. These coincidence factors did not change during the 2019 Update.

Capacity Assistance and Curtailable Load

The current capacity assistance agreement with Corner Brook Pulp and Paper Limited (“CBPP”) is due to expire at the end of winter 2022–2023. In the Reliability Model, it was assumed that capacity assistance would continue to be available from CBPP beyond the expiry of the current contract. Since the winter of 2014–2015, CBPP has been willing to enter into mutually beneficial capacity assistance arrangements with Hydro. It is assumed that similar arrangements will continue.

Vale Newfoundland and Labrador Limited’s (“Vale”) increased requirements in the fourth quarter of 2024 are associated with the conversion of oil-fired boilers to electric heating. The additional electric load is included in the Island Interconnected System load forecast and is assumed 100% curtailable upon Hydro’s request as a planning assumption. However, the duration and extent of the load curtailment need to be negotiated with Vale.

Additional load requirements from the conversion of Memorial University of Newfoundland’s oil-fired boilers to electric heating are also included in the Island Interconnected System load forecast and are assumed 100% curtailable upon Hydro’s request as a planning assumption. However, the duration and extent of the load curtailment need to be confirmed with Newfoundland Power.

4.2.3 Capacity by Asset Class

To ensure accurate modelling of its supply resources, Hydro incorporated detailed modelling of its capacity resources and power purchase agreements, incorporating probabilistic analyses. Further details are contained in the 2018 Filing.[64]

Thermal and Gas Turbines

Hydro has confirmed with Newfoundland Power that their corporate plan includes retirements of both their Greenhill and Wesleyville Gas Turbines, as they are nearing the end of their service lives, and should be excluded from the supply forecast used in Hydro’s Reliability Model. The capacity of the Greenhill Gas Turbine is 20 MW and the Wesleyville Gas Turbine is 8 MW, totalling 28 MW of capacity that has been removed from the supply forecast. Newfoundland Power is currently in the process of assessing what, if any, capacity additions may be required following the retirement of these units. Hydro

[64] “Reliability and Resource Adequacy Study,” Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 4.2.2.

will continue to communicate with Newfoundland Power to make sure any future additions that would materially impact Hydro's resource planning analyses are included.

The Reliability Model includes the probabilistic modelling of forced outages. When considering future possible operations of the Holyrood TGS as a backup generating facility, a Derated Adjusted Utilization Forced Outage Probability ("DAUFOP")[65] was calculated. The methodology describing the approach taken can be found in Attachment 4 of the "Long-Term Resource Plan" included as part of the 2022 Update.

4.2.4 Variable Energy Resources

Analysis of Effective Wind Capacity

Hydro continues to assume the capacity contribution of existing and incremental wind generation sources at 22% of the nameplate. However, this capacity contribution is heavily dependent on the location and penetration of wind generation. The Effective Load Carrying Capability Study was based on a small penetration of wind farms. Hydro recommends the capacity contribution of 22% should not be extrapolated to larger capacity wind farms; however, Hydro remains committed to further evaluation of the capacity contribution of wind as penetrations increase and the technology continues to evolve.

In addition, Hydro is currently supporting the Government of Newfoundland and Labrador's Wind Development Process. This process will include a third-party analysis to assess the amount of wind that can be integrated into Hydro's system, including preliminary interconnection information for future potential self-supply customers. The grid implications of wind integration into the existing system have not been included in this analysis, as the Wind Development Process is ongoing. It is recognized that wind integration is likely to have a material impact on system operations and future resource additions. Hydro will include the outcomes of this process as part of the 2023 Update.

4.2.5 Capacity Transfers: Imports and Exports

Only firm imports and exports are considered as part of Hydro's modelling, consistent with NERC standard practice to ensure capacity is not double counted between jurisdictions. Firm exports are

[65] The probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

added as a load and firm imports are treated as a reduction in load. The contractual requirements are used to derive an hourly profile for the exports or imports.

There are two commitments for firm exports—a commitment for firm capacity (Nova Scotia Block) and a commitment for firm energy (Supplemental Energy). Delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery occurring on August 17, 2021.[66] Delivery of Supplemental Energy[67] commenced in November 2021, with the first physical delivery occurring on November 1, 2021. As per the Energy and Capacity Agreement, in instances where the LIL is fully unavailable, Hydro is not obligated to deliver the Nova Scotia Block or Supplemental Energy. In instances where the LIL is partially available, the Nova Scotia Block and Supplemental Energy are delivered on a *pro rata* basis.

Currently, there are no long-term firm import contracts in place, although there is a possibility that import contracts could become available at some point in the future. Non-firm imports are not considered in the reliability analysis. This is considered a prudent approach to maintaining the adequacy of provincial supply.

4.2.6 Emergency Operating Procedures – Proposed Emergency Transmission Limits

Resources are dispatched by the Newfoundland and Labrador System Operator (“NLSO”) in accordance with “Operations Standard Instruction BA-P-012 (T-001) Operating Reserves” (“BA-P-012”),[68] which outlines the requirements to assess and maintain sufficient operating reserves to meet current and anticipated customer needs under normal operating conditions and for specific contingency situations that result in reductions to resources.

In the event of a developing or sudden supply shortage, the NLSO follows a number of mitigating actions (as outlined in BA-P-012) based on the system conditions at the time. While some of the actions can provide system relief on a short-term basis (e.g., the implementation of voltage reduction), from a long-

[66] Pursuant to the Energy and Capacity Agreement between Nalcor Energy and Emera Inc. (“Emera”), the Nova Scotia Block is a firm annual commitment of 980 GWh, supplied from the Muskrat Falls Hydroelectric Generating Facility on peak.
[67] Supplemental Energy is an amount of energy delivered to Emera in equal annual amounts over each of the first five years of operation of the Muskrat Falls Hydroelectric Generating Facility during the months of January to March and November to December during off-peak hours.
[68] For Hydro’s “Operations Standard Instruction BA-P-012 Operating Reserves,” please refer to Hydro’s response to PUB-NLH-002 from the *Reliability and Resource Adequacy Study Review* proceeding, <http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/rfis/PUB-NLH-002.PDF>

term system planning perspective, Hydro has not included the associated capacity benefits explicitly in its Reliability Model.

5.0 Probabilistic Capacity Planning Results

5.1 Hydro's Approach to System Reliability

Hydro's approach to reliability modelling is focused on determining when system reliability violates the targeted planning criteria. Violations determine the timing and the magnitude of the need for additional resources. For the 2022 Update, the study period is separated into two distinct planning periods, with separate reliability criteria and modelling approaches for each.

As capacity additions and retirements occur, the required planning reserve margin may also change, particularly if the attributes of the new resources being considered are materially different from the retired resources. For this reason, the planning reserve margin used to assess the reliability of the system prior to the retirement of the Holyrood TGS and the Hardwoods Gas Turbine would not be the same as post-retirement. This is primarily due to the high forced outage rates associated with the Holyrood TGS and Hardwoods Gas Turbine, which impact a significant portion of the on-Island supply resources. Any new generation that would potentially be built to replace this capacity would likely be significantly more reliable, reducing the need for reserves. This necessitates taking a different approach to assessing reliability in the period from 2023 to 2030 (i.e., the year in which the Holyrood TGS and the Hardwoods Gas Turbine are assumed to be retired), referred to in the 2022 Update as the "Bridging Period." Information on extending the Holyrood TGS and the Hardwoods Gas Turbine in the interim as well as their suitability as standby options in the long-term is contained in Sections 5.3 and 5.4 of the "Long-Term Resource Plan" included as part of the 2022 Update.

5.2 Bridging Period: 2023–2030

During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.[69] Demand response would also be available by entering into new or renewing existing interruptible contracts or pursuing aggregate-type solutions in

[69] The Stephenville Gas Turbine will be retired on March 31, 2024, as previously communicated in the "Reliability and Resource Adequacy Study – 2022 Update – Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 16, 2022.

the residential system in the future. Reliability was assessed by directly calculating LOLH in each year and comparing it against the 2.8 LOLH planning criterion. This calculation was done for a range of load forecasts, LIL capacities, and LIL forced outage rates, similar to the methodology used in the Near-Term Generation Adequacy Reports. Section 4.2.1 includes the range of LIL forced outage rates and capacities that were considered with the intent of providing upper and lower limits on a range of possibilities when assessing the impacts of the LIL on Island Interconnected System reliability.

The Bridging Period has been tentatively selected as the period between 2023 through 2030. After 2030, it is assumed that both the Holyrood TGS and the Hardwoods Gas Turbine are retired. However, there will likely be some overlap between the Bridging Period and the Future Period[70] while the existing thermal generation is retired and the new generation is brought into service.

The seven scenarios analyzed to assess system reliability under a range of potential system conditions are summarized in Table 2.

Table 2: Summary of Assumptions for Bridging Period

Scenario	LIL Capacity (MW)	LIL Bipole FOR (%)	Island Load Case	Labrador Load Case
Scenario 1: Reliable LIL	900	1%	Base	Base
Scenario 2: Reduced Capacity LIL: Base Case	675	5%	Base	Base
Scenario 3: Reduced Capacity LIL: High Island Load	675	5%	High	Base
Scenario 4: Reduced Capacity LIL: High Labrador Load	675	5%	Base	High
Scenario 5: Reduced Capacity LIL: High Provincial Load	675	5%	High	High
Scenario 6: Reduced Capacity LIL: High FOR	675	10%	Base	Base
Scenario 7: Low Capacity LIL: High FOR	475	10%	Base	Base

Table 3 presents the LOLH per year for each scenario with the Holyrood TGS, the Hardwoods Gas Turbine, and the Stephenville Gas Turbine having all retired on April 1, 2024 with no new resources added to the Newfoundland and Labrador Interconnected System. Reliability criterion (i.e., > 2.8 LOLH) violations are shaded red.

[70] The "Future Period" is defined as the period beyond 2030 (the Bridging Period).

Table 3: LOLH Results – No Generation Capacity Additions through 2030
Holyrood TGS, Hardwoods Gas Turbine, and Stephenville Gas Turbine Retired

Scenario	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1: LIL 900 MW, FOR 1%, Base Island/Base Labrador	1.9	7.7	8.2	7.8	7.7	7.5	8.6	10.4
Scenario 2: LIL 675 MW, FOR 5%, Base Island/Base Labrador	9.7	38.1	41.0	38.5	38.9	37.6	43.0	52.6
Scenario 3: LIL 675 MW, FOR 5%, High Island/Base Labrador	9.6	38.5	42.5	40.5	42.1	41.8	49.6	66.5
Scenario 4: LIL 675 MW, FOR 5%, Base Island/High Labrador	9.6	38.0	41.0	38.7	39.1	37.8	43.3	57.0
Scenario 5: LIL 675 MW, FOR 5%, High Island/High Labrador	9.8	38.5	42.5	40.5	42.3	42.2	50.5	73.1
Scenario 6: LIL 675 MW, FOR 10%, Base Island/Base Labrador	19.1	75.6	81.6	76.2	77.2	74.4	84.8	103.3
Scenario 7: LIL 475 MW, FOR 10%, Base Island/Base Labrador	21.7	98.0	104.6	99.5	101.1	101.4	115.7	152.0

The results in Table 3 clearly show that backup generation is required even if the LIL bipole is highly reliable and the forced outage rate is on the low end of the range used in this analysis.

Table 4 presents the LOLH per year for each scenario with only the Holyrood TGS extended through 2030, with both the Hardwoods Gas Turbine and the Stephenville Gas Turbine having been retired on April 1, 2024, to determine if reliability criteria could be met with the extension of the Holyrood TGS only while continuing with the planned retirement of both the Hardwoods Gas Turbine and the Stephenville Gas Turbine on April 1, 2024.

Table 4: LOLH Results – No Generation Capacity Additions
Holyrood TGS Extended through 2030

Scenario	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1: LIL 900 MW, FOR 1%, Base Island/Base Labrador	0.2	0.3	0.3	0.3	0.4	0.3	0.4	0.5
Scenario 2: LIL 675 MW, FOR 5%, Base Island/Base Labrador	0.8	1.6	1.5	1.5	1.6	1.7	1.8	2.6
Scenario 3: LIL 675 MW, FOR 5%, High Island/Base Labrador	0.8	1.5	1.7	1.7	1.8	1.9	2.3	3.6
Scenario 4: LIL 675 MW, FOR 5%, Base Island/High Labrador	0.8	1.5	1.6	1.6	1.7	1.7	1.9	2.8
Scenario 5: LIL 675 MW, FOR 5%, High Island/High Labrador	0.8	1.6	1.7	1.7	1.8	2.0	2.4	3.7
Scenario 6: LIL 675 MW, FOR 10%, Base Island/Base Labrador	1.5	3.0	3.2	3.2	3.2	3.5	3.7	5.2
Scenario 7: LIL 475 MW, FOR 10%, Base Island/Base Labrador	1.7	3.3	3.6	3.4	3.5	3.7	4.0	5.8

The results of Table 4 indicate that the availability of the LIL at partial capability, backed up by the Holyrood TGS, mitigates the extent of lost load in the majority of these scenarios.[71,72] As expected, as the LIL bipole forced outage rate increases, the risk to system reliability increases as it is a key driver impacting Island Interconnected System reliability. Secondary drivers include the LIL capacity assumption and the load forecast sensitivities. Scenarios 3 and 5 both show that a combination of a LIL bipole forced outage rate of 5% and the high Island load forecast creates reserve criterion violations and the need for additional resources by 2030, despite the Holyrood TGS being available. Similarly, Scenario 4 with a high Labrador load assumption is right at criteria, on the edge of also requiring additional resources in 2030. Scenarios 6 and 7 show that if the LIL bipole forced outage rate is as high as 10%, the LOLH planning criteria are violated starting in 2024 and all subsequent years of the Bridging Period, despite the continued availability of the Holyrood TGS. Overall, the need for additional on-Island resources is far more sensitive to the LIL bipole forced outage rate and Island load forecast than Labrador load assumptions. This is because the new generation on the Island decreases reliance on the

[71] Information on extending the Holyrood TGS is contained in Section 5.3 of the "Long-Term Resource Plan" included as part of the 2022 Update.
[72] Holyrood TGS reliability assumptions are explained in Attachment 4 of the "Long-Term Resource Plan" included as part of the 2022 Update.

capacity of the LIL, potentially allowing the existing generation in Labrador to serve the Labrador Interconnected System.

Table 5 presents the LOLH per year for each scenario with both the Holyrood TGS and the Hardwoods Gas Turbine extended to 2030, and the Stephenville Gas Turbine retired in 2024.

Table 5: LOLH Results – No Generation Capacity Additions
Holyrood TGS and the Hardwoods Gas Turbine Extended through 2030

Scenario	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1: LIL 900 MW, FOR 1%, Base Island/Base Labrador	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.4
Scenario 2: LIL 675 MW, FOR 5%, Base Island/Base Labrador	0.7	1.0	1.1	1.1	1.1	1.1	1.3	1.8
Scenario 3: LIL 675 MW, FOR 5%, High Island/Base Labrador	0.7	1.1	1.1	1.2	1.3	1.4	1.6	2.7
Scenario 4: LIL 675 MW, FOR 5%, Base Island/High Labrador	0.7	1.0	1.1	1.1	1.1	1.2	1.3	1.9
Scenario 5: LIL 675 MW, FOR 5%, High Island/High Labrador	0.7	1.1	1.2	1.2	1.3	1.3	1.6	2.7
Scenario 6: LIL 675 MW, FOR 10%, Base Island/Base Labrador	1.4	2.0	2.2	2.1	2.2	2.3	2.6	3.7
Scenario 7: LIL 475 MW, FOR 10%, Base Island/Base Labrador	1.4	2.3	2.3	2.3	2.3	2.6	2.8	3.9

Table 5 shows that extending both the Holyrood TGS and the Hardwoods Gas Turbine through 2030, further mitigates the risk of lost load in nearly all these scenarios, deferring the need for additional resources until 2029 at the earliest even with an assumed 10% bipole forced outage rate for the LIL. These results support continued investment to maintain the Holyrood TGS and the Hardwoods Gas Turbine in the interim until new resources can be added to the system.[73] As new capacity is added, existing thermal generation can be retired, while closely monitoring system reliability in the interim to ensure that the Muskrat Falls Hydroelectric Generating Facility is fully integrated and reliable prior to proceeding with on-Island retirements.

[73] Information on extending the Holyrood TGS and the Hardwoods Gas Turbine is contained in Sections 5.3 and 5.4 of the "Long-Term Resource Plan" included as part of the 2022 Update.

5.3 Long-Term Reliability Criteria

The Future Period, beyond 2030,[74] represents the long-term requirements for the system. In this period, it is assumed that the Holyrood TGS and the Hardwoods Gas Turbine are retired on December 31, 2030 and new sources of generation have been integrated into the Island Interconnected System to maintain system reliability. To assess reliability during this period, a planning reserve margin was established.[75] The year 2032 was selected as the representative year since at that time it is assumed, for this analysis, that new sources of generation have been integrated and planned retirements will have occurred.[76] Reliability was assessed by comparing available generation to load requirements against the planning reserve margin developed for the 2022 Update over a range of Island Interconnected System load growth scenarios. To determine an appropriate planning reserve margin required to satisfy the move to an enhanced reliability criterion of 0.1 LOLE, it was assumed that the LIL would have a bipole forced outage rate of 5% and a capacity of 675 MW. A bipole forced outage rate of 5% was selected as the mid-point in the range of bipole forced outage rate considered in this analysis. Hydro recognizes that the selected bipole forced outage rate could be higher or lower than 5%, which would have a material impact on the reserve margin. A LIL capacity of 675 MW was also assumed as a mid-point assumption. Variations in LIL capacity between 675 MW and 900 MW do not have a material impact on the planning reserve margin; rather, it is the bipole forced outage rate that remains the key driver. Hydro will continue to revise its planning reserve margin as more operational data becomes available for the LIL.

The LOLE and resultant planning reserve margin for the Island Interconnected System result is presented in Table 6. The enhanced reliability criterion of 0.1 LOLE has been assumed to determine the required planning reserve margin.

Table 6: Planning Reserve Margin Results

	Island Interconnected System[77]
LOLE	0.1
Planning Reserve Margin	36%

[74] 2030 is the latest time frame that required generation to back up the LIL is expected to be approved, constructed, and placed in service. This includes approximately one to two years of a transition period to ensure all new assets have been integrated into the system successfully.
[75] This methodology is the same as per the 2018 Filing and 2019 Update. Additional details are contained in the "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, sec. 5.1.
[76] To ensure incremental investment is made prudently, it is important to select a representative year that most closely represents anticipated long-term system conditions.
[77] The Planning Reserve Margin represented is inclusive of losses.

An Island Interconnected System reserve margin of 36% equates to approximately 480 MW of new generation that may be required by 2032, assuming that the LIL operates at 675 MW with a bipole forced outage rate of 5%. The proposed planning reserve margin has increased by 20% compared to the 2019 Update, primarily due to the increase in the LIL bipole forced outage rate assumption from 0.0114% to 5%. Once the LIL is commissioned and operational data is obtained, it will allow for refinement of the bipole forced outage rate assumption and the resulting Island Interconnected System planning reserve margin.

In the 2018 Filing and the 2019 Update, Hydro proposed to plan on a Newfoundland and Labrador Interconnected System basis due to the expectation that the LIL would be commissioned with an expected bipole forced outage rate of 0.0114%. From a planning perspective, this allowed Hydro to plan for the Newfoundland and Labrador Interconnected System as a single integrated system. This meant that adding load on either the Labrador Interconnected System or the Island Interconnected System had approximately the same impact on Newfoundland and Labrador Interconnected System reliability. As the LIL bipole forced outage rate increases and bipole outages become the primary driver of generation shortfall on the Island Interconnected System, there is far less correlation between Labrador Interconnected System load and Newfoundland and Labrador Interconnected System reliability. Given the material increase of the LIL bipole forced outage rate assumption compared to the 2018 Filing and 2019 Update, it may be necessary to reassess this approach and instead adopt separate planning criteria for the Island Interconnected System and the Labrador Interconnected System. The LIL bipole forced outage rate is the primary driver of the generation shortfall on the Island Interconnected System and the bipole forced outage rate assumption has a material impact on the planning reserve margin. Hydro is committed to reassessing the required reserve margin as well as reliability criteria for both the Island Interconnected System and the Labrador Interconnected System once the LIL is commissioned and sufficient operational data is available.

Chart 1 depicts the Island Interconnected System firm capacity for both the Bridging Period and the Future Period against the base Island load forecast and planning reserve margin of 36%, assuming that the LIL is available at 675 MW with a bipole forced outage rate of 5%. It is important to note that additional load growth on the Island beyond 2032 would require new resources in addition to the potential 480 MW discussed herein.

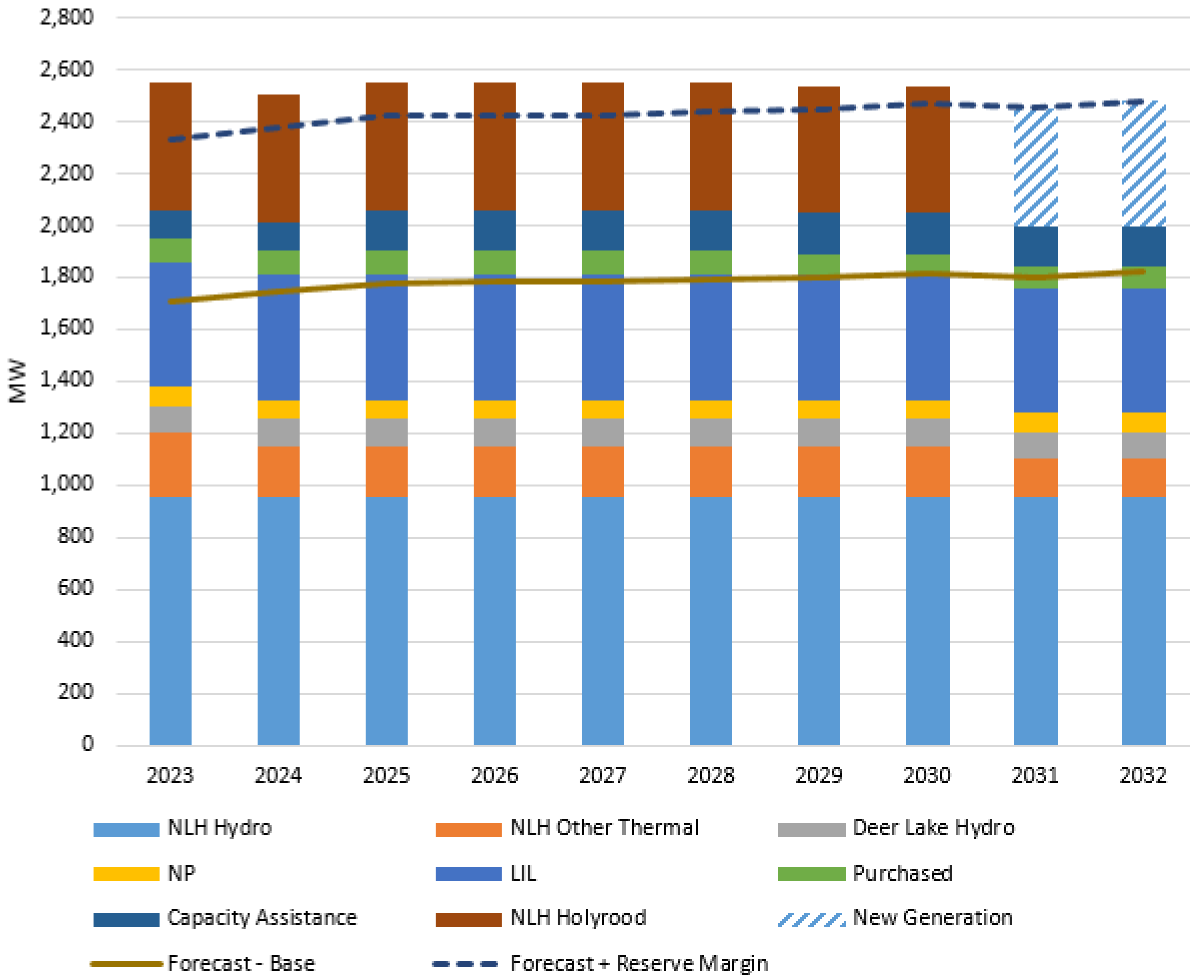


Chart 1: Firm Capacity versus Forecast Peak Demand[78,79,80]

1 ### 5.3.1 Operational Reserve Requirements Results

2 As detailed in Section 3.2.2, Table 7 presents operational reserves required to be available in accordance
3 with NPCC criteria.

[78] Forecast peak demand in graph includes losses.
[79] Explanation of Legend: "NLH" refers to Newfoundland and Labrador Hydro; "NP" refers to Newfoundland Power hydro and thermal; "Deer Lake Hydro" is modelled as the generation at Deer Lake and load out of CBPP; "Capacity Assistance" includes CBPP, Vale diesels, Vale curtailable, Memorial University of Newfoundland curtailable, and Newfoundland Power capacity assistance; "NLH Other Thermal" includes to Newfoundland and Labrador Hydro's combustion turbines and diesels. The LIL capacity is assumed 675 MW less losses and the Nova Scotia Block.
[80] Purchases reduce in 2031 due to the retirement of existing wind generation.

Table 7: Operational Reserve Requirements Results (MW)

	Operational Reserve Required
10-Minute Reserves	197.5
30-Minute Reserves	99
Total	**296.5**

By 2032, the peak load is estimated to be 1,822 MW.[81] Therefore, the total capacity requirement is estimated to be 1,822 MW plus the planning reserve margin of approximately 657 MW for a total potential requirement of 2,479 MW by 2032, which may require the addition of at least 480 MW of firm generating capacity. For reference, the available capacity in 2032, without the addition of new resources and including the retirement of the Holyrood TGS, the Hardwoods Gas Turbine, and the Stephenville Gas Turbine, is approximately 1,998 MW.[82] Both the probabilistic criteria (the planning reserve margin) and the deterministic criteria (the operational reserve requirement) must be met; however, the resultant reserve margin is sufficient to meet the operational reserve requirements presented in Table 7. Hydro recognizes that the driver for the high planning reserve margin is an estimated LIL bipole forced outage rate in the absence of operational data post-commissioning. Hydro agrees that new resource additions are necessary; however, Hydro expects the planning reserve margin to change, as operational data becomes available, hence recommending resource additions in a phased approach as more information becomes available in the coming years.

As noted in the 2018 Filing, the assessment of the firm plant output of the Muskrat Falls Hydroelectric Generating Facility will continue to be analyzed as it continues to operate.[83] If it is determined that the Muskrat Falls Hydroelectric Generating Facility is proven capable of rated output (i.e., 824 MW) through the winter, the operational reserve requirements will increase from 296.5 MW to 309 MW.[84] Further information on the operational reserve required in the case where the LIL is treated as the loss of the first contingency (i.e., energy-only line) is contained in Section 5.6 of the "Long-Term Resource Plan" included as part of the 2022 Update.

[81] The peak load of 1,822 MW in the base case is inclusive of losses.
[82] The total capacity of 1,998 MW includes 675 MW of LIL capacity, less losses and the Nova Scotia Block.
[83] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 5.2.
[84] The addition of the 10-minute reserve requirement (206 MW) and the 30-minute reserve requirement (103 MW) yields a reserve requirement of 309 MW.

6.0 Conclusion

A comprehensive set of results and the supporting analysis from Hydro's resource planning process was previously filed with the Board as part of the 2018 Filing. That analysis proposed changes to resource planning criteria stemming from system changes resulting from new interconnections. Proposed changes included:

- The migration to planning on a regional and sub-regional basis; and
- The migration to the adoption of the LOLE target of 0.1.[85]

The 2019 Update and the 2022 Update are filed as a complement to the 2018 Filing. The 2022 Update is intended to provide additional detail on matters Hydro has continued to investigate. The LIL reliability remains a key factor in the ability to economically achieve proposed planning criteria. Given the level of uncertainty that remains, Hydro continues to recommend the following:

- Continuing the evaluation of supply adequacy, both probabilistically and deterministically; and
- Maintaining sufficient operating reserves to align with NPCC operational reserve requirements.

Hydro continues to recommend the following, but is committed to reassessing these recommendations in the 2023 Update as Hydro continues to gather information while working with stakeholders to advance associated files:

- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Newfoundland and Labrador Interconnected System;
- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System;
- Planning for the Newfoundland and Labrador Interconnected System on a regional and sub-regional basis; and
- Extending pre-existing Island Interconnected System energy criteria to the Newfoundland and Labrador Interconnected System.

[85] Once the Muskrat Falls Project Assets are fulling integrated and considered reliable.

Volume I, Attachment 1

2022 Reliability & Resource Adequacy Process Review

MEMORANDUM

TO: Newfoundland & Labrador Hydro

FROM: Daymark Energy Advisors

DATE: October 3, 2022

SUBJECT: 2022 Reliability & Resource Adequacy Process Review

In preparation for the 2022 Reliability and Resource Adequacy ("R&RA") filing with the PUB, Daymark Energy Advisors ("Daymark") was engaged to provide an independent review of Newfoundland and Labrador Hydro's ("Hydro") ongoing efforts into how to meet the reliability and resource adequacy requirements of the provincial electric system considering the additions of the Labrador-Island Link ("LIL"), the Maritime Link ("ML"), and the Muskrat Falls Generating Station. Hydro seeks to ensure that it continues to provide acceptable levels of reliability, while balancing the overall cost of the system.

This memorandum is a high-level overview of the advisory support provided by Daymark to Hydro in the overall approach to the evaluation of its reliability criteria.

As part of this effort, as documented in detail in separate Daymark memos, Daymark has provided Hydro with:

1) Research related to historical DC transmission forced outage rates[1] and,

2) a review of Hydro's approach to load forecasting[2].

These efforts are further summarized in the following sections.

DC TRANSMISSION FORCED OUTAGE RATE REVIEW SUMMARY

Daymark gathered information pertaining to metrics, methodologies, experience, and issues that utilities or other energy industry participants utilize or have witnessed relevant to outages of high voltage direct current (HVDC) paths.

Focusing on the Nordic areas of Europe, with coastal conditions of a similar latitudinal plane as the LIL and use of land and undersea cables, history shows HVDC link capacity unavailability rates (considering

[1] Daymark memo, "Considerations for HVDC Outage/Unavailability Rates", dated 9/19/2022
[2] Daymark memo, "Independent Review of Hydro's Load Forecast 2022", dated 9/23/2022

total outages and limitations) as high as 35% per year. In 2020, unavailability rates ranged from 0.3% to 30%. On average, the HVDC links in the Nordic region have an average capacity unavailability of over 10% for the years of 2018, 2019, and 2020. Over the last few years, unavailability has been caused in nearly equal parts by maintenance outages, disturbance outages, and limitations.

The reported experience of the Swedish utility that owns the SouthWest Link HVDC path provides an example of potential complication and risk of getting a large-scale HVDC project fully operational. The SouthWest Link project suffered a delay in commercial operation of seven years. That seven-year delay was caused by 22 separate attempts/postponements of full commercial operation.

LOAD FORECASTING PROCESS REVIEW SUMMARY

As part of our independent review of the Reliability and Resource Adequacy Study ("R&RA") methodologies, Daymark reviewed the load forecast methodology to assess its base and alternative futures forecasting methodology and potential for load requirements. Daymark also investigated how Hydro addresses the many uncertainties and brackets the scenarios to address potential energy need to better inform planning and actions recommended.

Daymark concludes that Hydro's forecasting is sound and incorporates the ability to analyze multiple potential futures, while addressing the many uncertainties in the industry; Hydro's multiple future options supports the evaluation of R&RA as the local economy and industry changes move ahead.

Although we conclude that the methodologies used by Hydro are consistent with industry practice, we recommend Hydro address, in each planning cycle, the continuing need to enhance its ability to incorporate significant industry change into the forecast to assess the implications and speed of policy changes to address decarbonization, adoption of additional renewable resources such as wind and off shore wind, and adoption of new technologies that drive industrial business increases in the region.

RELIABILITY ANALYSIS

In 2018 Daymark was engaged to assist Hydro in a review of alternative industry approaches to resource adequacy. At that time our review identified the 1 day-in-10 years (0.1 days per year) LOLE standard as the most prevalent approach. However, we also noted that while the adoption of the criteria itself prevailed in the industry, the method by which modelling, and determination of supply adequacy was conducted is subjective and varies between utilities.

Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications. For Hydro, the economics of resource adequacy is a critical consideration given the recent investments in Muskrat Falls and the associated transmission infrastructure.

In most U.S. and Canadian power systems, the 0.1 LOLE standard is interpreted to mean that planning reserve margins need to be high enough that involuntary load shedding due to inadequate supply would occur only once in ten years. One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events.

Further, the manner in which transmission interconnections, interruptible loads, voltage reductions, and load uncertainty are treated, all add to the potential variability in the level of planning reserve margin required. There is no one-size-fits-all approach to the determination of resource adequacy. The approach taken to developing a planning reserve margin is dependent on the specific circumstances and needs of a given utility. The difference between these interpretations of the 1-in-10 standard and generation planning assumptions can translate to potentially significant differences in required planning reserve margins.

Hydro is currently planning to an LOLH of 2.8. As previously stated in Section 7.2.1, Volume II of the 2019 RRA Update, Hydro intends to move to a 0.1 LOLE once the Muskrat Falls supply and the related transmission infrastructure are fully integrated into the Newfoundland and Labrador Interconnected System and the thermal generation at the Holyrood TGS, the Hardwoods GT, and the Stephenville GT have all been retired, currently anticipated by no later than 2030.

For the 2022 R&RA assessment, Hydro's key assumptions include the continued operation of Holyrood TGS and Hardwoods GT through 2030 (or until an adequate replacement is in place), treating the LIL as 675 MW of firm capacity with a 5% forced outage rate, load forecast variations (discussed in Daymark's Load Forecast memo dated September 23, 2022), and an on-island interruptible load of 158 MW. No other capacity contribution is assumed available from voltage reductions or transmission interties. The full list of assumptions is documented in 2022 RRA filing.

To better understand and plan for the resource adequacy implications of varying the key assumptions, Hydro has created several alternative scenarios to test the sensitivity of the resulting reserve margin to varying key assumptions. Specifically, Table 1 that follows shows the variable sensitivities tested.

Table 1. Sensitivity Analysis

Scenario	LIL Capacity	LIL FOR	Island Load	Labrador Load
S1: Reliable LIL	900 MW	1%	Base	Base
S2: Reduced Capacity LIL: Base Case	675 MW	5%	Base	Base
S3: Reduced Capacity LIL: High Island Load	675 MW	5%	High	Base
S4: Reduced Capacity LIL: High Labrador Load	675 MW	5%	Base	High
S5: Reduced Capacity LIL: High Provincial Load	675 MW	5%	High	High
S6: Reduced Capacity LIL: High FOR	675 MW	10%	Base	Base
S7: Low Capacity LIL: High FOR	475 MW	10%	Base	Base

The use of this type of bandwidth or sensitivity analysis is standard practice in the development resource adequacy assessments.

Beyond the sensitivity analysis, Hydro has also investigated the implications of the LIL not being available for six-week period during a peak load winter period. Given the distance, rugged terrain, remoteness as well as overhead and undersea nature of the LIL, and response for repair time, we believe it is prudent to assess the implications of not having the LIL for an extended period. In the event of an outage a six-week repair time was assumed based on studies that were performed by external consulting firms[1].

To further identify any possible deficiencies in Hydro's ability to meet its customers' energy requirements Hydro also performs a Firm Energy Analysis. Using Firm Energy as a planning criteria was used previously in the 2018 and 2019 R&RA analyses, however it was not reported because the available energy well exceeded the projected supply. Hydro completed the current assessment of its ability to meet firm energy requirements in consideration of historic hydraulic availability consistent with the planning practices of other utilities with major hydraulic resources.

[1] Reliability and Resource Adequacy Study - Additional Considerations of the Labrador-Island Link - Reliability Assessment and Outcomes of the Failure Investigation Findings – NL Hydro, December 22, 2021

OVERALL PLANNING PROCESS ASSESSMENT

Overall, Hydro's planning process as it relates to assessing resource adequacy is generally consistent with approaches used in the industry. Hydro's assumptions and rationale as they relate to transmission interconnections, interruptible loads, voltage reductions, and load uncertainty are all documented in the 2022 RRA filing and are consistent with Hydro's stated goal of providing reasonable reliability at the lowest cost. Reasonable being defined by Hydro as a) consistent with past practice and b) supportive of provincial decarbonization goals.

Future Considerations

Consistent with Hydro's intent to evolving to a higher standard of reliability (i.e., LOLE 0.1) once the LIL is fully commissioned and integrated into the Newfoundland and Labrador Interconnected System and the Holyrood TGS, the Hardwoods GT, and the Stephenville GT have all been retired, Daymark offers the following considerations as Hydro continues to evolve its Resource Planning Process to be more consistent with industry norms.

To address an immediate need to back-up the LIL on an interim basis, Hydro is planning to extend the operation of Holyrood GTS and Hardwoods GT, potentially through 2030. This decision is based on the lack of readily available options for backing up the LIL.

Continuing to rely on aging thermal facilities (i.e., Holyrood TGS and Hardwoods GT) as critical to reliably meet Hydro's on-Island electricity needs is a growing concern that bears close monitoring. Holyrood TGS was designed as a base load unit, and as such it is ill-equipped to reliably handle the thermal cycling and fast starting requirements to serve as a backup for the LIL, as Hydro has acknowledged. To better position Holyrood TGS in this backup role, Hydro intends to invest in capital improvements to the facility. In addition, operational changes are being made to how the units are dispatched to hopefully improve Holyrood's reliability and responsiveness. During periods of anticipated high demand Holyrood TGS will be placed online prematurely in anticipation of a potential need. Hydro will continue to look to develop operational strategies to optimize the dispatch of the units to manage startup challenges while minimizing cost. While these strategies may be effective in improving Holyrood TGS reliability, actual experience is needed to properly evaluate their effectiveness.

Strong consideration should be given accelerating their replacement prior to 2030. Daymark is aware and very much supportive of Hydro's ongoing efforts to study what would be required to accelerate the integration of renewable energy into the electrical grid.

Given the remote location of the Muskrat Falls units and the rugged and remote nature of the transmission path connecting it to the Island, combined with growing local load requirements in

Labrador, treating Muskrat Falls as firm capacity and a direct replacement for on-Island generation merits further analysis.

Operational (30- and 10-minute reserves) are driven by what constitutes the largest and second largest single contingency events on the Newfoundland and Labrador Interconnected System. The loss of individual units at Holyrood TGS have historically been considered the largest contingency events. Once the LIL is fully integrated the Holyrood TGS will be replaced by the individual units at MFGS as the largest contingency events. Once fully integrated, the loss of a LIL tower technically represents the largest single contingency, double element risk to the NLIS. However, during the conceptual and planning phases of the Muskrat Falls project, Hydro specified that the loss of the LIL not be considered as a single contingency given the robust nature of the tower design.

Daymark believes excluding the loss of the LIL as the largest single contingency on the Newfoundland and Labrador Interconnected System merits further review, especially considering the absence of any meaningful operational history for the LIL. Given that a tower failure alone (a software failure could also trigger the same result) would result in a complete bipole outage, Hydro may be better served to treat the LIL as energy only and not as firm capacity or the equivalent of on-Island capacity as is currently the case.

As part of the 2022 RRA, Hydro has studied the implications of treating the LIL as an energy-only line for informational purposes only. Currently, the closest Hydro comes to full alignment with the above concern is the “Shortfall Analysis” with the assumed total bipole loss of the LIL for 6-weeks during a winter peak period. Daymark recognizes the potentially significant cost implications that need to be balanced with the reliability gained from such a shift in planning philosophy.

Volume I, Attachment 2

Considerations for HVDC Outage/Unavailability Rates

DAYMARK ENERGY ADVISORS

MEMORANDUM

TO: Newfoundland and Labrador Hydro

FROM: Daymark Energy Advisors

DATE: September 19, 2022

SUBJECT: Considerations for HVDC Outage/Unavailability Rates

As part of the Reliability & Resource Adequacy Review scope of services agreed upon between Newfoundland and Labrador Hydro (NLH) and Daymark Energy Advisors (Daymark) dated April 22, 2022, Daymark has gathered the following information pertaining to metrics, methodologies, experience and issues that utilities or other energy industry participants utilize or have witnessed relevant to outages of high voltage direct current (HVDC) paths. The process for data gathering included:

1. Identifying other HVDC paths in other regions of the world where environmental conditions may be like those of NLH – specifically conditions perilous to transmission infrastructure (e.g., freezing temperatures, snowfall, wind speeds). An inventory of international HVDC paths was developed from multiple data sources including CIGRE, a global community of power system experts; cable manufacturer ABB (now Hitachi); and the Wikipedia web page for "List of HVDC projects".
2. Researching metrics and methodologies used by operators/regulators governing those HVDC paths identified from the inventory of HVDC data – specifically information from the European Network of Transmission System Operators for Electricity (ENTSO-E).
3. Identifying historical unavailability rates of HVDC links in the coastal, Nordic regions of Europe where environmental threats to transmission infrastructure (on land and undersea), in part, mimic those of the NLH landscape.
4. Researching HVDC paths in the Nordic region of Europe that have experienced delays in commercial operations/availability due to issues with control systems, specifically those related to implementation of software systems.

INVENTORY OF WORLDWIDE HVDC PATHS

Using simple internet searches and resources such as CIGRE, a list of existing, internationally located HVDC paths was developed. This list, while perhaps not exhaustive, included over 100 HVDC paths in the northern hemisphere and about 10 in the southern hemisphere.

Looking at other land areas in the same approximate latitudinal plane as the NLH Labrador Island Link (LIL) HVDC path, with coastal conditions and opportunities for undersea cables, attentions focused around the Nordic areas of Europe.

Figure 1 shows a map of the earth including latitudes and longitudes. The approximate location of the LIL is shown with a red star and Nordic countries of Europe (including Norway, Sweden, Finland, etc.) are highlighted in blue.

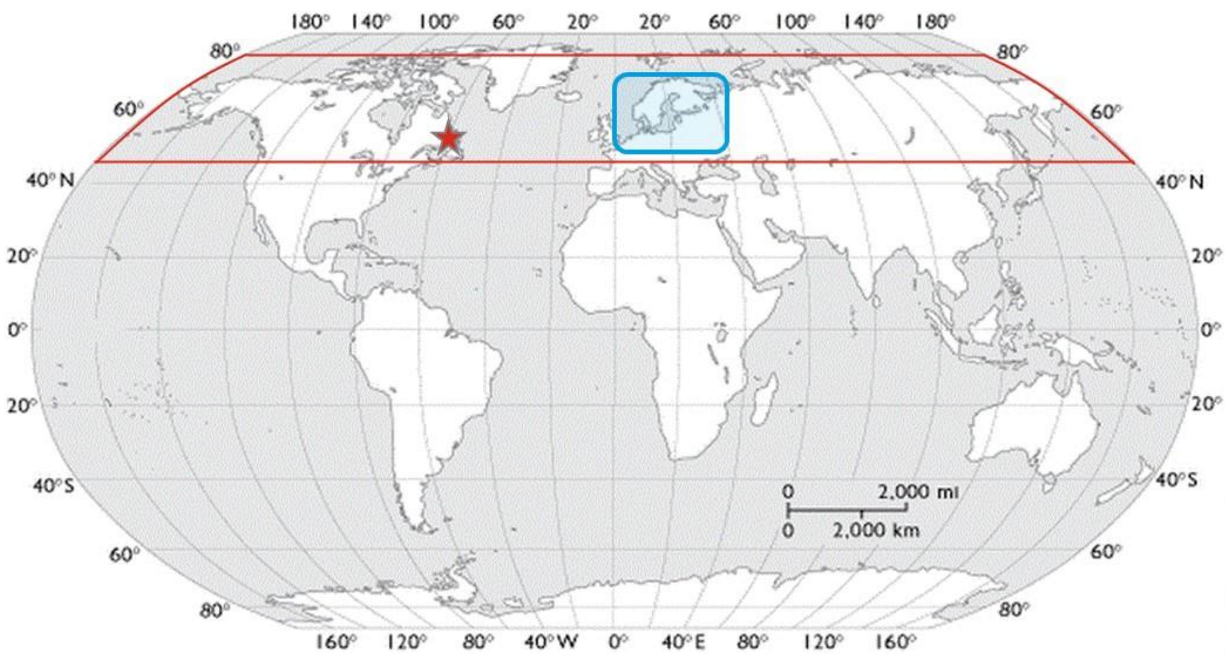
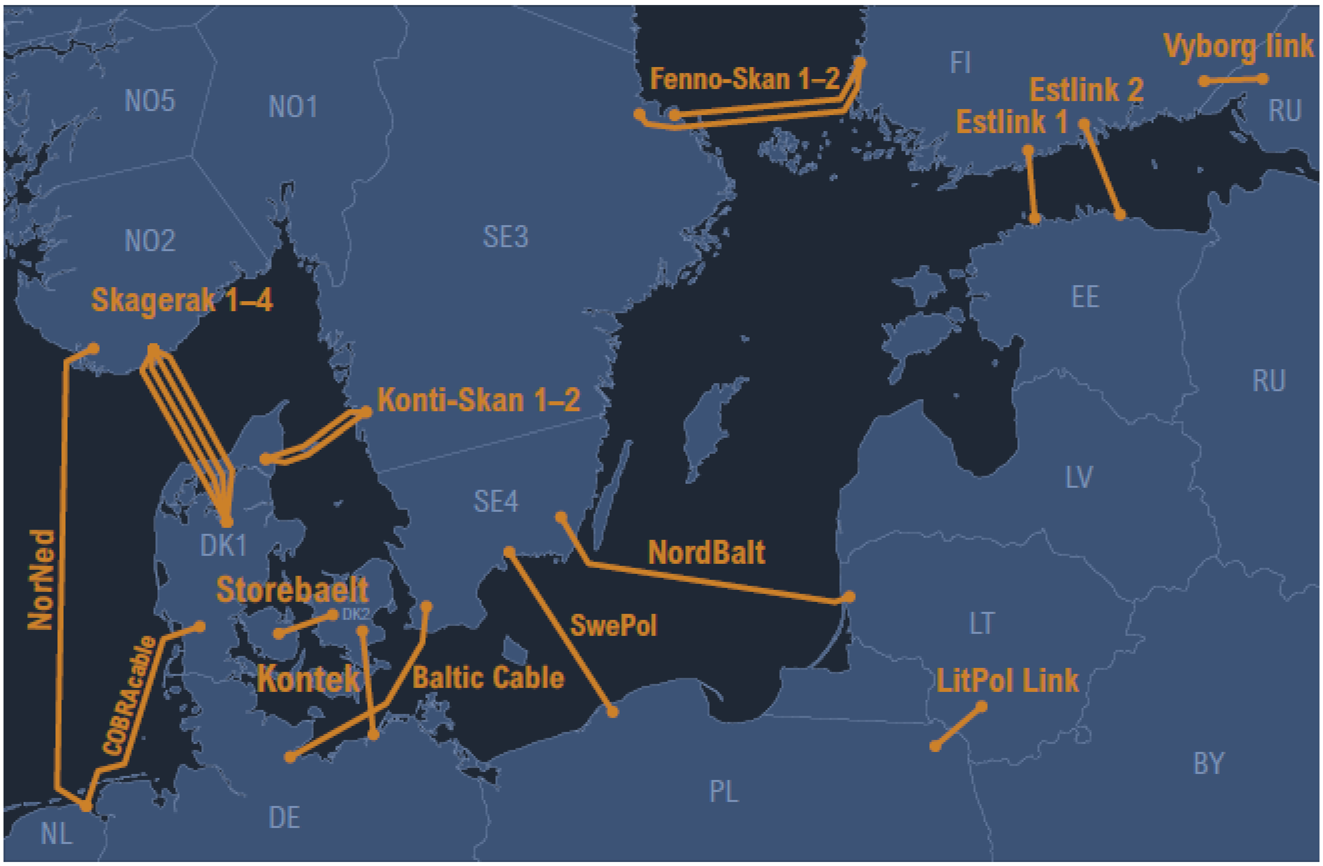


Figure 1. Latitudinal Comparison of LIL and Nordic Europe

There are nearly 20 HVDC lines spanning areas around northwestern Europe. The ENTSO-E's system operations committee puts out an annual report of HVDC utilization and unavailability statistics for the region.

ENTSO-E HVDC UTILIZATION AND UNAVAILABILITY STATISTICS

Figure 2 shows the locations of HVDC paths and bidding zones discussed in the ENTSO-E's *HVDC Utilisation and Unavailability Statistics 2020* report published on June 24, 2021.

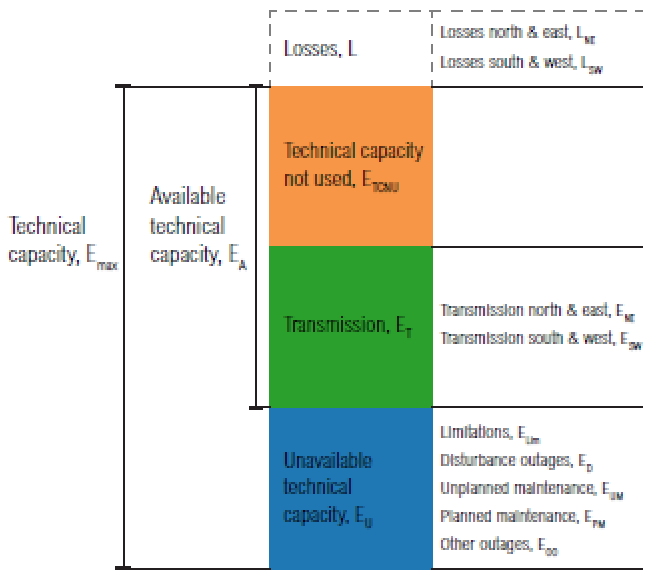


Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 2. Locations of HVDC Paths, Northwestern Europe

Many of these HVDC paths are, in large proportion, undersea cables with smaller portions of routing on-land. The LitPol and Vyborg links are purely land-based. The majority of NLH's LIL path is on-land with a small portion traversing undersea.

Figure 3 shows the metrics used by the ENTSO-E when presenting historical HVDC utilization and unavailability data. In this report, an HVDC path is considered to have a certain technical capacity. At any given time, however, all or some portion of that capacity may become unavailable. This could happen due to a total outage for maintenance or some disturbance (e.g., weather disturbance causing a fault limiting energy transfer to zero) or a partial outage (i.e., limitation or derate) wherein energy may still flow, but at a lesser quantity than the full technical capacity of the path. As such, this report considers the full technical capacity of an HVDC path to comprise a portion of available technical capacity and a portion of unavailable technical capacity. The available technical capacity is further divided into categories of transmission (i.e., the amount of energy that actually flows) and technical capacity not used (i.e., capacity that is available but not needed for system operations). Losses across path components are not considered in this context.



Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 3. ENTSO-E Metrics Used in HVDC Utilization and Unavailability

In this report, the term "utilization" refers to the green portion shown in Figure 3 which is the available technical capacity that is used. The term "unavailability" refers to the blue portion shown in Figure 3 which represents capacity that cannot be used due to a limitation or total outage.

Figure 4 shows a table from the ENTSO-E report. This table presents annual unavailability percentages of HVDC links by bidding zones.

	2012	2013	2014	2015	2016	2017	2018	2019	2020
DK1–DK2	2.9%	9.9%	4.6%	2.4%	2.8%	1.6%	2.2%	2.5%	0.3%
DK1–NL								5.1%	29.3%
DK2–DE	5.8%	3.9%	3.5%	5.2%	10.4%	14.3%	25.9%	3.8%	30.0%
FI–EE	2.6%	5.0%	14.7%	5.8%	3.6%	0.6%	3.6%	2.2%	2.7%
FI–SE3	27.3%	17.2%	5.4%	9.5%	1.5%	1.2%	1.1%	4.7%	0.9%
LT–PL					14.0%	10.1%	6.1%	3.6%	8.6%
NO2–DK1	2.4%	7.9%	10.5%	6.5%	4.8%	18.0%	12.7%	27.0%	23.6%
NO2–NL	3.4%	19.3%	4.5%	4.2%	8.1%	8.4%	13.8%	13.0%	16.9%
RU–FI	9.8%	1.3%	0.4%	0.0%	1.5%	2.3%	5.2%	5.4%	11.5%
SE3–DK1	4.7%	10.7%	16.1%	16.7%	5.5%	6.7%	4.3%	15.8%	16.6%
SE4–DE	22.1%	18.1%	6.6%	12.5%	20.4%	27.1%	35.0%	26.2%	18.7%
SE4–LT					25.7%	16.5%	22.0%	7.6%	5.5%
SE4–PL	0.2%	3.3%	7.1%	7.3%	15.3%	5.9%	4.2%	14.0%	12.8%
Grand Total	9.8%	9.9%	7.2%	6.7%	7.8%	8.9%	10.2%	11.2%	13.5%

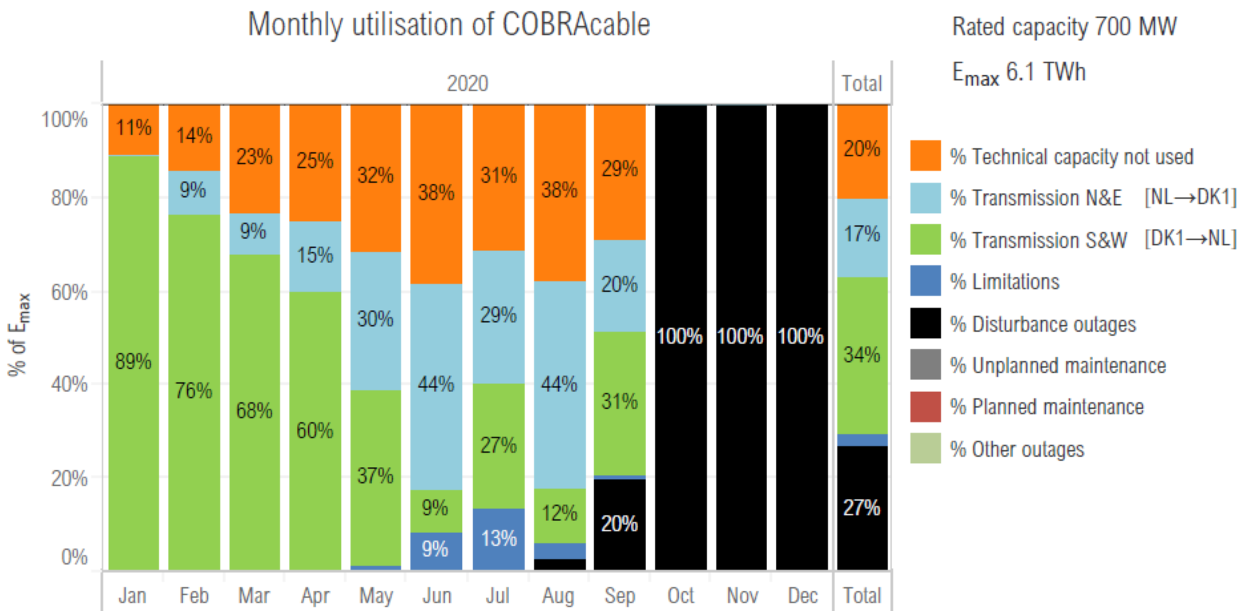
Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 4. ENTSO-E Annual Unavailability Rates by % Capacity, HVDC Paths by Zone 2012-2020

This collection of HVDC links have experienced annual unavailability rates as high as 35%. The Vyborg link between the bidding zones of RU and FI had a 0% unavailability rate in 2015, but 65% of its availability was unused. In 2020, unavailability rates for all reported links ranged from 0.3% to 30%. In aggregate, annual outage rates have been over 10% for each of the years from 2018 to 2020.

While planned maintenance outages were commonly reported across most of the HVDC paths, some of the larger outages and limitations were attributable to submarine cable faults, weather impacts (e.g., fallen tree during storm), and equipment issues (e.g., pumps, oil flow relay, cooling and auxiliary systems, smoothing reactor, AC filter problems, and one fire in an AC filter).

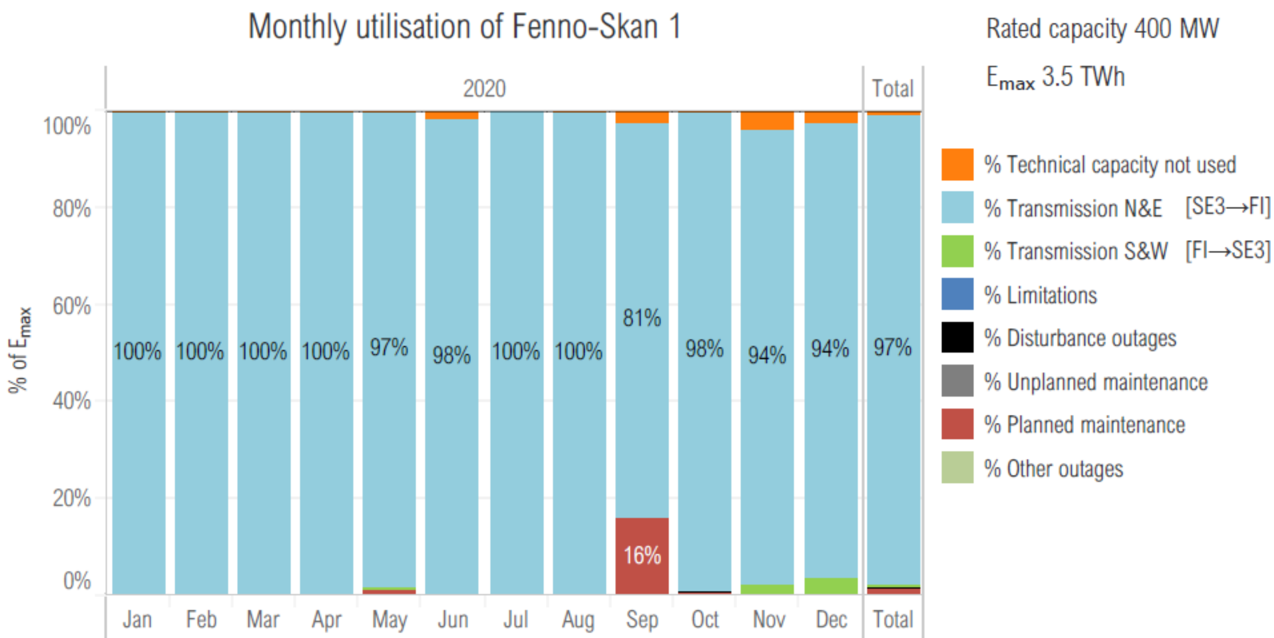
The following figures show specific metric values for the two HVDC links –the COBRAcable tie between Denmark and Netherlands and the Fenno-Skan 1 tie between Sweden and Finland. Details of these two paths are shown as examples as the COBRAcable is an example of the largest of disturbance outages and limitation and Fenno-Skan 1 represents the tie with the largest utilization rate.



Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 5. ENTSO-E 2020 Monthly Utilization of the COBRAcable HVDC Path

The COBRAcable 2020 utilization data shows major disturbance outage(s) spanning from September through December 2020 contributing to an annual total unavailability rate of 27%. Per the ENTSO-E report, there was a minor outage to a glycol pump in August and a submarine cable fault in September that lasted into January 2021.

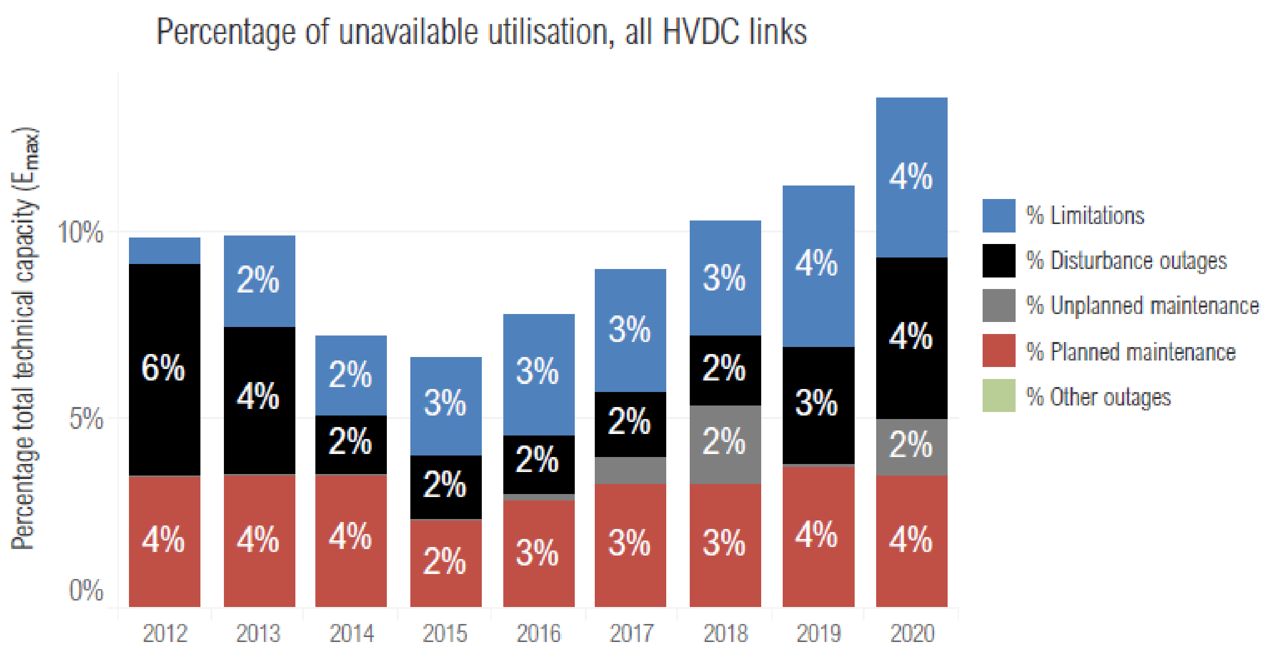


Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 6. ENTSO-E 2020 Monthly Utilization of the Fenno-Skan 1 HVDC Path

The Fenno-Skan 1 2020 utilization data shows planned maintenance that occurred in September. Very few other interruptions were seen. The report indicates the annual maintenance lasted for four days. There were three additional planned maintenance outages for correcting purposes and three disturbance outages with minimal impact due to faults in the cooling and auxiliary systems and DC measurement. In total for 2020, Fenno-Skan 1 was a little more than 97% utilized, 1% of the technical capacity was not used, 1.5% attributed to planned maintenance, and about 0.1% to disturbance outages.

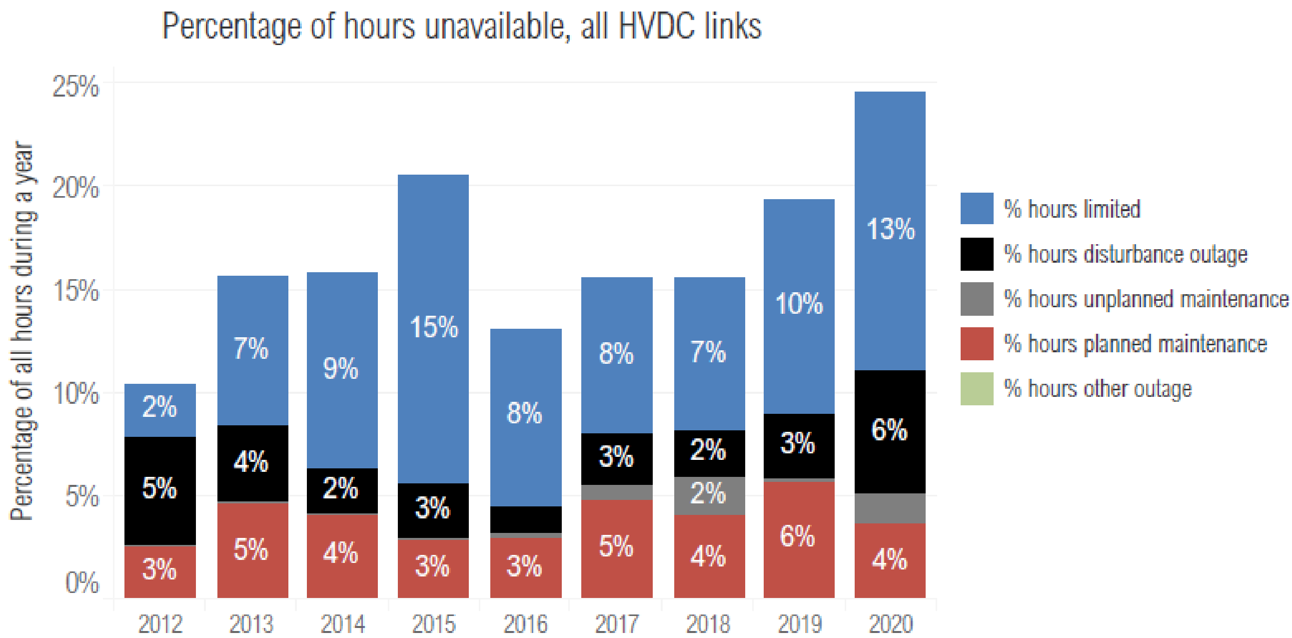
Figure 7 shows the aggregate annual unavailability rates (for the 19 HVDC paths reported) from 2012 through 2020.



Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 7. ENTSO-E Annual Unavailability Rates by % Capacity, All HVDC Paths 2012-2020

Figure 8 shows the aggregate unavailability of the HVDC paths as a percentage of hours.



Source: ENTSO-E HVDC Utilisation and Unavailability Statistics 2020, June 24, 2021.

Figure 8. ENTSO-E Annual Unavailability Rates by % Hours, All HVDC Paths 2012-2020

SWEDEN'S SOUTHWEST LINK

Sweden's SouthWest Link is a transmission project authorized in 2005 to strengthen the transmission capacity between mid- and southern-Sweden and to strengthen operational reliability in southern Sweden. The project includes a 250 km HVDC path – 60 km of which is overhead line and 190 km of which is underground cable. The HVDC path has a capacity of 2 x 600 MW. The HVDC section of the SouthWest Link was scheduled for commercial operation in 2014 but did not achieve commercial operation until July 2021[1].

According to a September 2021 article in Elinstallatäleren (a Swedish industry magazine focused on electrical engineering)[1] the project suffered 22 delays. The project's owner, Svenska kraftnät, stated in its 2020 Annual Report[2], that the delays were "because the supplier had difficulties in completing the

[1] Granmar, M. (2021, September 13). Hela historien om sydvästlänken. Elinstallatören. Retrieved July 28, 2022, from https://www.elinstallatoren.se/2021/09/hela-historien-om-sydvastlanken/
[2] Svenska kraftnät. (2021). (rep.). Annual Report 2020 (Case No. SVK 2020/3721). Sundbyberg, Sweden. https://www.svk.se/siteassets/om-oss/organisation/finansiell-information/arkiv/arsredovisning-affarsverket-svenska-kraftnat-2020.pdf

converter stations, which convert overhead lines' alternating current to direct current in cables." The supplier of the converter stations was originally Alstom which later became GE Grid Solutions.

KEY TAKEAWAYS

The ENTSO-E data shows consideration of limitations (i.e., ability to deliver something more than 0% but less than 100% of total capability) in addition to complete outages from disturbances, maintenance, and the like.

Focusing on the Nordic areas of Europe, with coastal conditions of a similar latitudinal plane as the LIL and use of land and undersea cables, history shows HVDC link capacity unavailability rates (considering total outages and limitations) as high as 35% per year. In 2020, unavailability rates ranged from 0.3% to 30%. On average, the HVDC links in the ENTSO-E report have an average capacity unavailability of over 10% for the years of 2018, 2019, and 2020. Over the last few years, unavailability has been caused in nearly equal parts by maintenance outages, disturbance outages, and limitations.

The reported experience of the Swedish utility that owns the SouthWest Link HVDC path provides an example of potential complication and risk of getting a large-scale HVDC project fully operational. The SouthWest Link project suffered a delay in commercial operation of seven years. That seven-year delay was caused by 22 separate attempts/postponements of full commercial operation.

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Reliability and Resource Adequacy Study 2022 Update

Volume III: Long-Term Resource Plan

newfoundland labrador hydro

Contents

List of Attachments

1.0 Introduction

Newfoundland and Labrador Hydro's ("Hydro") "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update") is filed as a complement to the Reliability and Resource Adequacy Study ("2018 Filing")[1] and the "Reliability and Resource Adequacy Study – 2019 Update" ("2019 Update").[2] The "Long-Term Resource Plan" (Volume III) of the 2022 Update addresses Labrador Island Link ("LIL") reliability, the Holyrood Thermal Generating Station ("Holyrood TGS") as a long-term standby option for the LIL, and the long-term resource plan that is required to meet the reliability expectations defined in the "Study Methodology and Planning Criteria" (Volume I) of the 2022 Update. The planning reserve margin, detailed in the "Study Methodology and Planning Criteria" of the 2022 Update, forms the basis for the addition of incremental resources identified in the resource planning process. Another case, which contemplates the investment required to partially mitigate the loss of the LIL bipole for up to six weeks, is further discussed in the 2022 Update.

There remains a high level of uncertainty regarding the potential load growth on the Labrador Interconnected System, due to significant customer requests following the implementation of the *Network Additions Policy – Labrador Interconnected System* ("*Network Additions P*olicy"),[3] and on the Island Interconnected System, due to electrification and electric vehicle ("EV") adoption and the possibility of new mines and wind/hydrogen projects. The grid implications of wind integration into the existing system have not been included in this analysis, as the Wind Development Process[4] is ongoing; however, it is recognized that wind integration is likely to have a material impact on system operations and future resource additions.

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[1] Reliability and Resource Adequacy Study, Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] Reliability and Resource Adequacy Study – 2019 Update, Newfoundland and Labrador Hydro, November 15, 2019.
[3] Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*, <https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf>
[4] The Wind Development Process is an ongoing process that is being led by the Government of Newfoundland and Labrador and supported by Hydro to enable wind generation in the province. As part of this process, Hydro is undertaking a third-party study with the goal of determining the amount of wind that can be integrated into Hydro's system, including preliminary interconnection information for future potential self-supply customers.

Furthermore, the proposed Clean Electricity Standard[5] has brought into question resource options that would traditionally have been recommended but are now uncertain as a future resource option (i.e., fossil fuel-burning combustion turbines). Therefore, the 2022 Update does not include an expansion plan that contemplates all these uncertainties; rather, it identifies capacity shortfalls in the year they are forecast to occur based on a range of possibilities. Hydro is committed to assessing the impact of the Wind Development Process, the outcome of the *Network Addition Policy* process, other pending system growth possibilities, and further review of the Clean Electricity Standard and its impact on resource options as part of the "Reliability and Resource Adequacy Study – 2023 Update" ("2023 Update").[6]

Resource planning is inherently an imprecise process. While many variables, such as load forecast, forecasted retirements and asset reliability, are analyzed to understand the implications on costs and rates, these variables are not precise. As such, the results of this analysis provide an opportunity for discussion with stakeholders on key decision inputs to be used in the future planning of the Newfoundland and Labrador Interconnected System.

2.0 Existing Assets and Infrastructure

2.1 Summary of Existing Assets and Infrastructure

Hydro's existing assets and infrastructure continue to play a key role in its supply mix. The existing assets and infrastructure that are part of the Newfoundland and Labrador Interconnected System are integrated into the Resource Planning Model. The Resource Planning Model uses criteria from the Reliability Model to determine cost-effective alternatives to meet system reliability expectations. The assumptions made in the Resource Planning Model are consistent with those made in the Reliability Model.[7] Detailed information on revised forced outage rates and forced outage rate assumptions used in the 2022 Update can be found in Attachment 1 to the "Long-Term Resource Plan" included in the 2022 Update.

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[5] "Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035," Environment and Climate Change Canada, March 15, 2022, <https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html>

[6] Hydro intends to file its 2023 Update in the fall of 2023.

[7] Detailed information of the existing assets and infrastructure that are part of the Newfoundland and Labrador Interconnected System generation resources are contained in the "Reliability and Resource Adequacy Study - 2022 Update - Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 16, 2022.

1 A summary of the firm capacity[8] of Hydro's existing generation assets is listed in Table 1.

Table 1: Summary of Existing Generation Assets (MW)[9,10]

Generation Assets	Firm Capacity
Hydraulic Generation	
Muskrat Falls[11]	
Unit 1	196.2
Unit 2	196.2
Unit 3	196.2
Unit 4	196.2
Subtotal Muskrat Falls[12]	784.6
Bay d'Espoir[13]	
Unit 1	76.5
Unit 2	76.5
Unit 3	76.5
Unit 4	76.5
Unit 5	76.5
Unit 6	76.5
Unit 7	154.4
Subtotal Bay d'Espoir	613.4
Cat Arm[14]	
Unit 1	67.0
Unit 2	67.0
Subtotal Cat Arm[15]	134.0
Other Hydro	
Hinds Lake[16]	75.0
Granite Canal[17]	40.0
Paradise River[18]	8.0
Upper Salmon[19]	84.0
Mini Hydro	-
Subtotal Other Hydro	207.0
Total Hydraulic Generation	**1,739.0**

[8] Firm capacity refers to the amount of generation capacity available for production or transmission expected to be available at the annual peak when the unit is fully operational.
[9] Totals may not add due to rounding.
[10] As of January 2023.
[11] Muskrat Falls Hydroelectric Generating Facility ("Muskrat Falls").
[12] Difference in Installed Capacity and Gross Capacity is related to potential tailrace icing conditions in the Lower Churchill River in the winter period. This is based on preliminary analysis and will be evaluated as operating data is obtained with the dam and plant is in place.
[13] Bay d'Espoir Hydroelectric Generating Facility (Bay d'Espoir").
[14] Cat Arm Hydroelectric Generating Station ("Cat Arm").
[15] The installed capacity of the units at Cat Arm Units 1 and 2 are 68.5 MW each; however, combined they are derated to 67 MW due to penstock limitations
[16] Hinds Lake Hydroelectric Generating Station ("Hinds Lake").
[17] Granite Canal Hydroelectric Generating Station ("Granite Canal").
[18] Paradise River Hydroelectric Generating Station ("Paradise River").
[19] Upper Salmon Hydroelectric Generating Station ("Upper Salmon").

Generation Assets	**Firm Capacity**
Thermal Generation	
Holyrood TGS	490.0
Gas Turbines	
Happy Valley Gas Turbine	25.0
Hardwoods Gas Turbine	50.0
Holyrood Gas Turbine	123.5
Stephenville Gas Turbine	50.0
Subtotal Gas Turbine	738.5
Diesels	
Holyrood Diesels[20]	8.5
Hawkes Bay Diesel Generating Station	5.0
St. Anthony Diesel Generating Station	9.7
Subtotal Diesels	23.2
Total Thermal Generation	**761.7**
Power Purchases	
Exploits Grand Falls and Bishop's Falls[21]	63.0
Star Lake	18.0
CF(L)Co[22]	
Recapture Energy	300.0
TwinCo[23] Block	225.0
St. Lawrence Wind	6.0
Fermeuse Wind	6.0
Rattle Brook	-
New World Dairies	-
Total Power Purchases	**618.0**
Total NLH[24] System Supply	**3,118.7**
Other Island Generation Sources	
Newfoundland Power[25] (Hydro)	58.0
Newfoundland Power (Standby)	16.5
Total Other Island Generation Sources	**74.5**
Total Deer Lake Power Owned	**104.0**
Total System Supply	**3,297.2**

[20] Following environmental assessment, the Holyrood Diesels are rated to produce 8.5 MW on a continuous basis for long-term planning.
[21] The Exploits facility has an installed capacity of 95.6 MW.
[22] Churchill Falls (Labrador) Corporation ("CF(L)Co").
[23] Twin Falls Power Corporation Limited ('TwinCo").
[24] Newfoundland and Labrador Hydro ("Hydro").
[25] Newfoundland Power Inc. ("Newfoundland Power").

3.0 Stakeholder Engagement

The energy landscape has changed significantly since the stakeholder engagement work in support of the 2018 Filing. Planning is underway for additional stakeholder engagement actions, including an additional digital engagement exercise launching in 2023. This opportunity will be open to all electricity customers in the province and will help us understand current perspectives on cost and reliability in our province.

Hydro's ongoing stakeholder outreach activities with commercial and industrial customers will continue through the fall of 2022 and beyond as planning, research, and decision-making is advanced with respect to the reliability of our energy system.

4.0 Load Forecasts

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. This is a key input to the resource planning process, which ensures sufficient resources are available consistent with applied reliability standards. For the Newfoundland and Labrador Interconnected System, the load forecast is segmented into the Island Interconnected System and Labrador Interconnected System, as well as utility load (i.e., Domestic and General Service loads of Newfoundland Power Inc. ("Newfoundland Power") and Hydro) and industrial load.[26] The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems.[27,28] It also involves the development and analysis of potential new loads associated with electrification (e.g., EV adoption[29] and conversions of heating systems to electric heat).

The resource planning process considers a range of potential load forecast scenarios, rather than a single forecast. This allows for the evaluation of the sensitivity of results under differing economic conditions and growth opportunities. For the 2022 Update, a range of forecasts was developed independently for the

[26] Hydro has five industrial customers on the Island and two Industrial customers in Labrador.
[27] Long-term economic forecast for the province is taken from "Budget 2022 Change is in the air" Government of Newfoundland and Labrador, April 7, 2022, <https://www.gov.nl.ca/budget/2022/wp-content/uploads/sites/6/2022/04/Budget-2022-Speech.pdf>
[28] Local fuel price projection derived from S&P Global's long-term oil price forecast, May 2022.
[29] A study on EV adoption and impacts is included as Attachment 2 to the "Long-Term Resource Plan" included as part of the 2022 Update.

Island and Labrador; specifically, two load scenarios for each. In combination, those forecasts resulted in the evaluation of four discrete load scenarios.[30,31]

4.1 Economic Variability based on Provincial Economic Overview

Newfoundland and Labrador showed signs of economic recovery in 2021. Consumer spending and the real estate market surpassed pre-COVID-19-pandemic levels, while other economic indicators, such as the labour market and household disposable income, improved throughout the year.

Significant increases in the prices of iron ore, copper, and nickel, along with increased production, resulted in a 36.4% increase in the value of mineral shipments from Newfoundland and Labrador in 2021 compared to 2020. The value of oil production also increased by 43.2%—largely due to significantly higher oil prices. The seafood sector continued to remain a significant contributor to the provincial rural economy, with the value of fish landings reaching a record high in 2021.

Tourism activity also rebounded in 2021 when the province reopened to non-essential travel from within Canada. Overall economic activity in the province increased, with real GDP[32] increasing by 3.5% from 2020. Employment levels also experienced a small gain, increasing by 2.9% compared to 2020.

Looking forward through the medium term (i.e., one to five years), there are several developments that will positively influence provincial economic activity, in both Labrador and the Island. Several major oil projects (i.e., Bay du Nord and West White Rose) could increase investment and contribute to employment gains. In 2018, Grieg NL's Placentia Bay Aquaculture Project was released from environmental assessment and is expected to be fully operational by 2025. Continued increased interest in aquaculture is expected to expand the overall fishing and aquaculture industry.

The mining sector continues to have encouraging developments, with 2021 setting a nine-year high for exploration expenditures. Marathon Gold Corporation continues to advance its Valentine Gold Project,

[30] As noted within the "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019, vol. I, sec. 4.2.4, Hydro continues to use P50 weather conditions as the basis of its modelling exercises and the baseline for its planning analysis. At this time, Hydro is not including additional forecast combinations for P90 weather conditions; however, Hydro continues to assess the impact P90 conditions may have on the demand forecast. For further information, please refer to Section 4.5.
[31] An independent review of Hydro's load forecast is included as Attachment 3 to the "Long-Term Resource Plan" included as part of the 2022 Update.
[32] Gross domestic product ("GDP").

with construction scheduled to commence late in 2022 and first production expected in 2024. Vale Newfoundland and Labrador Limited ("Vale") continues to proceed with the development of two underground mines at the Voisey's Bay Mine, with first production from one of the underground mines in 2021. This project is a large capital investment and a long-term source of nickel concentrate for the Long Harbour Processing Plant.

Over the medium term, adjusted real GDP is forecast to increase, with increases in exports being driven by iron ore production and the expected restart of operations at the refinery in Come by Chance. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that lower oil production and lower mineral prices will hinder overall economic growth in 2022; however, non-residential activity in the near term, stemming from major projects, will contribute to positive economic growth.[33,34]

While the current provincial government's fiscal situation remains relatively challenging, the underlying local market conditions for electric power operations through the medium and long term in the context of provincial energy requirements suggest modest increases in energy requirements throughout the forecast period.[35] Table 2 provides the provincial economic assumptions, as forecast by the Department of Finance, Government of Newfoundland and Labrador.[36] These inputs form the basis of Hydro's load forecast models.

Table 2: Provincial Economic Indicators – 2022 Planning Load Forecast

Economic Indicators	2021–2027	2021–2032
Adjusted Real GDP at Basic Prices[37] (% per year)	1.3%	0.9%
Real Disposable Income (% per year)	0.4%	0.5%
Average Housing Starts (Number per year)	1,115	1,133
End of Period Population (Thousands)	524.8	525.2

[33] "Provincial Economic Forecast," TD Economics, June 22, 2022, <https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Jun2022.pdf>
[34] "Provincial Outlook," Royal Bank of Canada, June 7, 2022, <https://royal-bank-of-canada-2124.docs.contently.com/v/provincial-outlook-june-2022-final-pdf>
[35] The energy outlook is conditioned by electricity prices in which the customer rate impacts of the Muskrat Falls Project are assumed mitigated.
[36] "Budget 2022 Change is in the air," Government of Newfoundland and Labrador, April 7, 2022, <https://www.gov.nl.ca/budget/2022/wp-content/uploads/sites/6/2022/04/The-Economy-2022.pdf>
[37] Adjusted GDP excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for residents.

4.2 Island Load Forecast Scenarios

Total Island Interconnected System load is the summation of interconnected utility load and industrial customer loads as well as bulk transmission and distribution losses incurred serving the customer load requirements on the system.

Two scenarios were developed for the Island Interconnected System based on potential retail electricity rates, provincial economic growth, and a shift towards electrification. Table 3 presents the forecast scenarios for utility load growth on the Island Interconnected System that includes the load requirements for Newfoundland Power and for Hydro's Rural customers. Of note are the potential load possibilities for the Island Interconnected System, which are driven by the provincial economic outlook and the uncertainty of electrification and EV penetration.

- **Case I: Base:** Representative of the base provincial economic forecast, a moderate growth forecast for EV adoption, and an electricity price forecast that has a built-in estimate of the potential rate impact due to generation additions required for reliability.[38,39]
- **Case II: High Growth:** Representative of a high-growth provincial economic forecast and high-growth forecasts for EV adoption and building electrification.

The rate forecast is consistent with Case I: Base. Through the medium term, the economic growth expectations for the province coupled with the alternate electrification outlook indicate utility load requirements are primarily dependent on the level of electrification during the period. The load forecast results also indicate that the extent of positive growth in the longer term can be expected to be influenced by the level of provincial economic growth.

[38] The forecast also takes into account the Government of Newfoundland and Labrador's current plan for electrification of its own buildings.

[39] The underlying electricity rate aligns with The Government of Newfoundland and Labrador's rate mitigation target of 14.7 cents per kWh, escalating at 2.25% per year, as referenced in the "Technical Briefing Rate Mitigation," Government of Newfoundland and Labrador, July 28, 2021 filed as part of the "Items Impacting the Delay of Hydro's Next General Rate Application – Further Update," Newfoundland and Labrador Hydro, August 27, 2021. An estimated rate impact of generation expansion builds was utilized to asses the impact on the Island Interconnected System load forecast. This is considered a high-level estimate of what the rate impact potential could be based on an estimate of the cost of builds over the ten-year forecast period.

Table 3: Island Utility Electricity Load Growth Summary – 2022 Load Forecast[40]

		2021–2027[41,42,43]	2021–2032[44]
Case I: Base	MW	11.9%	15.8%
	GWh	6.9%	11.0%
Case II: High Growth	MW	12.9%	19.4%
	GWh	8.2%	15.3%

1 Chart 1 highlights that the load forecasts largely move together in the early part of the study period.
2 Following 2027, divergence in load forecasts can be observed as the difference in the electrification and
3 provincial economy outlook between cases increases. By the end of 2032, the forecast period, a variance
4 of 67 MW is observed between Case II: High Growth Case and Case I: Base.

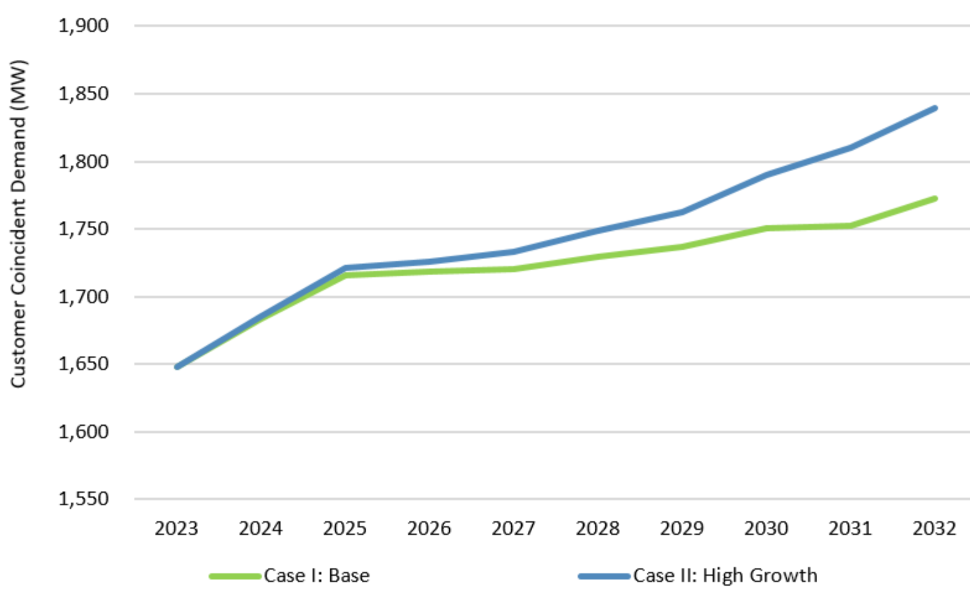

Chart 1: Island Interconnected System Forecast Annual Peak Demand Requirements[45,46]

[40] Utility load is the summation of Newfoundland Power and Hydro Rural requirements.
[41] The 2021 peak is not weather adjusted, contributing to some of the increase in in peak requirements.
[42] The Utility demand forecast includes approximately 22 MW of potential interruptible load in 2027.
[43] Interruptible load is a load, typically commercial or industrial, that can be interrupted in the event of a capacity deficiency in the supplying system.
[44] The utility demand forecast includes approximately 49 MW of potential interruptible load in 2032.
[45] The forecast values exclude transmission losses and station service.
[46] The customer coincident demand forecasts include approximately 22 MW of potential interruptible load in 2024 and 49 MW of potential interruptible load in 2025 to 2032.

Existing Industrial customer load requirements for the Island Interconnected System for 2023 through 2032 reflect the peak load requirements indicated by the customers. Additional forecast industrial loads for Case I: Base and Case II: High Growth include new mining load for the Valentine Gold Project and load requirements associated with the conversion of commercial and industrial customer's heating systems to electric heat. Case II: High Growth also includes modest additional industrial load growth associated with prospective mining sector growth. Chart 2 provides the annual energy requirements for both Case I: Base and Case II: High Growth.

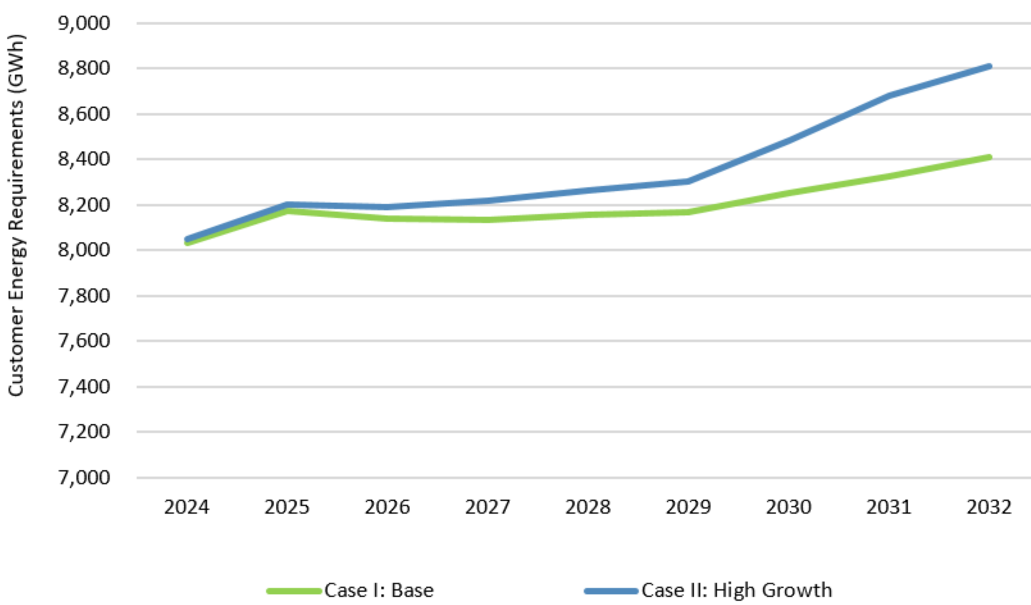

Chart 2: Island Interconnected System Forecast Annual Energy Requirements[47]

4.3 Labrador Load Forecast Scenarios

The Labrador Interconnected System load includes the power and energy requirements of the iron ore industry in western Labrador and Hydro's Rural customers. The communities include Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and the Churchill Falls town site.

Table 4 presents Case I: Base Case and Case II: High Growth for the total Labrador Interconnected System over the study period. The base forecast reflects Hydro's Rural Load Forecast Spring 2022, which includes existing data centre requirements and existing industrial loads. Case II: High Growth was developed to

[47] The forecast values exclude transmission losses and station service.

include requests for service submitted to Hydro under evaluation in the context of the *Network Additions Policy*.[48] Specifically, some of the additional load requirements in Case II: High Growth are for the existing Industrial customers, such as the Department of National Defence at 5 Wing Goose Bay, and other firm requirements from non-data centre customers, totalling 330 MW. Service requests from the I currently total 1,300 MW, exceeding the amount included in Case II: High Growth, and are further explained in Section 4.4. As there remains a high level of uncertainty about the total service requests in Labrador, only requests from existing Industrial customers have been included in Case II: High Growth. As the *Network Additions Policy* process advances, Hydro will continue to assess the level of service requests to include in the load forecast or to assess as sensitivities to the base case as appropriate.

Table 4: Labrador Interconnected System Electricity Load Growth Summary – 2022 Load Forecast[49,50,51]

		2021–2027	**2021–2032**
Case I: Base	MW	12.0%	13.5%
	GWh	9.2%	10.1%
Case II: High Growth	MW	33.5%	79.5%
	GWh	31.3%	83.3%

Chart 3 highlights that the load forecasts largely move together in the first years of the study period. Following 2025, divergence in load forecasts occurs as load addition requests in Labrador are approved and connected. There is uncertainty on the timing of these additions with new connections being dependent upon the outcome of the *Network Additions Policy* process (see Section 4.4). Chart 4 provides the annual energy requirements for Case I: Base and Case II: High Growth for the Labrador Interconnected System.

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[48] In *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 7(2021), Board of Commissioners of Public Utilities, March 17, 2021, the Board approved a *Network Additions Policy* for Labrador that laid out the rules for cost allocation to customers when transmission investments are triggered by customer load on the Labrador Interconnected System. Such a policy is standard practice in utilities and protects all customers from unfair cost allocation. "Labrador Interconnected System Network Additions Policy – Summary Report," Newfoundland and Labrador Hydro, December 14, 2018, <http://www.pub.nf.ca/applications/NLH2018NetworkAdditions/policy/From%20NLH%20-%20Labrador%20Interconnected%20System%20Network%20Additions%20Policy%20-%20Summary%20Report%20-%202018-12-14.PDF>

[49] Electricity load includes the summation of Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and Industrial customers.

[50] Peaks (MW) are from terminal station delivery points and are coincident with the Labrador Interconnected System peak. These peaks are presented on an annual peak basis and include firm requirements for Industrial customers as well as 7.4 MW of non-firm customer demand.

[51] Electricity loads do not include retails sales for Churchill Falls, which has an annual energy load of 3.0 GWh and a non-coincident peak of 0.3 MW.

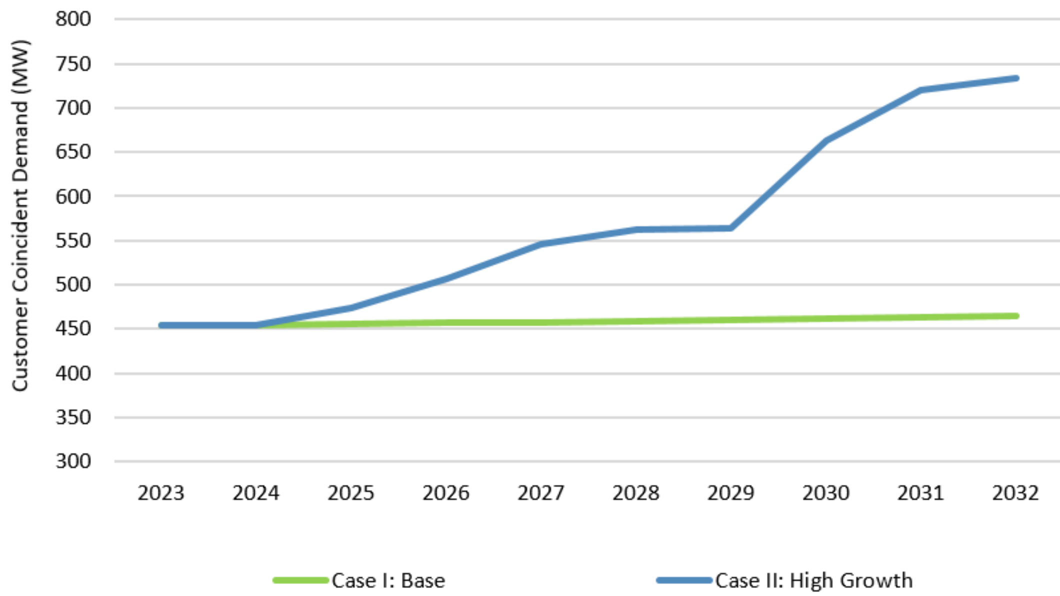

Chart 3: Labrador Interconnected System Forecast Annual Peak Demand Requirements[52,53]

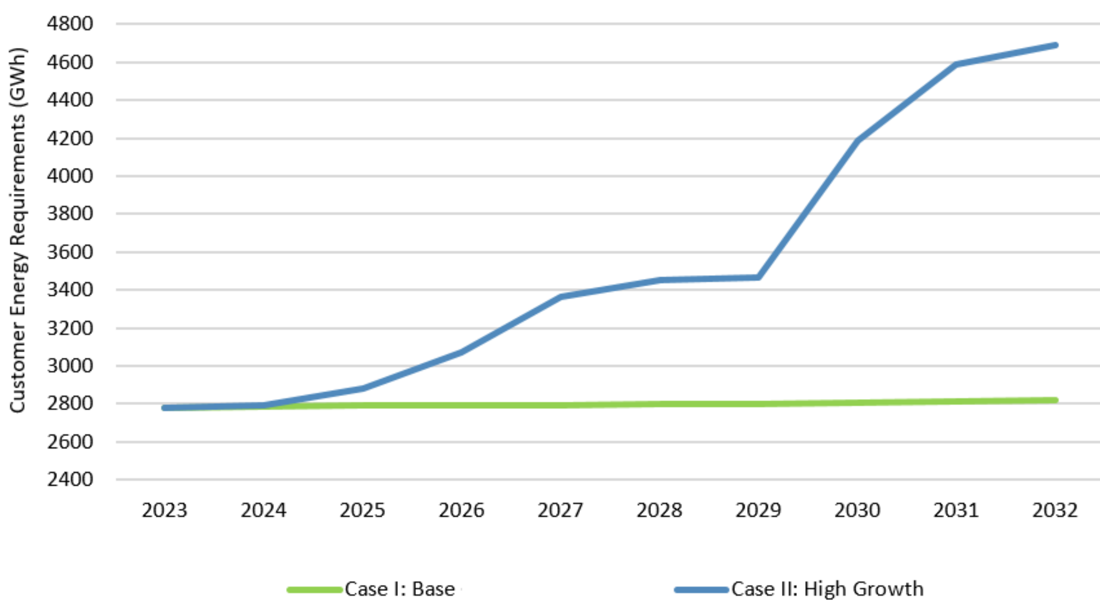

Chart 4: Labrador Interconnected System Forecast Annual Energy Requirements[54]

[52] The forecast values exclude transmission losses and station service.
[53] The customer coincident demand forecasts include approximately 6.5 MW of interruptible load.
[54] The forecast values exclude transmission losses and station service.

4.4 Network Additions Policy – Labrador Interconnected System

In March 2021, Hydro received formalized customer requests for incremental firm load in Labrador, following the implementation of the *Network Additions Policy*. Initially, Hydro reached out to all potential proponents asking them to submit applications indicating their projected load and location requirements. In response, Hydro received requests for approximately 8,000 MW of firm load on the Labrador Interconnected System.

During the fourth quarter of 2021, Hydro completed a high-level system impact analysis to determine indicative cost estimates of the transmission and generation additions required to serve incremental loads of 300 MW, 650 MW, and 1,000 MW for each of the three regions in Labrador (east, central, and west). After sharing the results of the high-level system impact analysis with the potential customers, 25 customers representing approximately 2,000 MW of load, confirmed their interest in proceeding with the interconnection process.

This level of load requests far exceed existing generation available on the Labrador Interconnected System and would trigger the need for significant incremental generation. Therefore, prior to progressing with the interconnection process, Hydro opted to communicate further information to the applicants on the projected cost of supply, associated rates, and estimated timeline to supply these large incremental load requests. The intent was to be transparent with such costs and offer the opportunity for applicants to confirm their continued interest.

In March 2022, Hydro met with all applicants and provided the projected cost of supply, possible associated rates, and estimated timeline to supply. Following this, 21 customers, representing approximately 1,300 MW of load, confirmed their continued interest in proceeding with the interconnection process.[55]

The next step in the interconnection process is a gated design process involving up to four distinct stages:

- Stage 1: Preliminary Assessment;
- Stage 2: System Impact Study;

[55] Service requests from crypto currency companies and data center customers represent 840 MW of the remaining requests.

- Stage 3: Facilities Study; and
- Stage 4: Implementation.

The process of interconnecting a large customer begins with a formal request for interconnection by the customer. Hydro has met with each of the applicants and progress has been made in defining the required study details. However, this process has been complicated by the multitude of large customers requesting interconnection, which generates requirements for upgrades to the bulk electrical system in each region. Since the number of applicants, the magnitude of the load requests, and the existing bulk electrical system infrastructure vary greatly in each region, the progress of the interconnection study process also varies for each region. Currently, in eastern and central Labrador, the process continues to progress in Stage 1, while in western Labrador, the process is progressing in Stage 2.

During Stage 3, design is advanced from the conclusions reached in Stage 2 and Class 3[56] cost estimates and Level 2 schedules[57] are prepared. At Stage 3, the customer will be presented with a formal quote for the Upstream Capacity Charge.[58] While the *Network Additions Policy* studies the need for transmission expansion, given the likely need for new generation resources, an assessment of Hydro's ability to supply the loads will also be completed at this stage. If the remaining load requests cannot be served with existing generation, a generation expansion plan will be developed and any cost impacts will be communicated. A tentative schedule for service that incorporates transmission upgrades and, if required, generation builds will be presented to the customer. Formal interconnection agreements would then be established. Hydro would proceed to seek approval from the Board of Commissioners of Public Utilities ("Board") of any capital upgrades that may be required. At that time, the load additions would be included in Hydro's base load forecast.

At each stage of study,[59] customers are provided with information upon which to decide whether to proceed further with their interconnection application. As such, the final number of customers and final

[56] The Association for Advancement of Cost Engineering ("AACE") Class 3 cost estimate is an estimate based on preliminary design documentation. The accuracy of the cost estimate varies between less than 20% or more than 30% of the estimated cost.
[57] A Level 2 schedule is the first level of scheduled detail where logical task relationships may be shown. It often includes a breakout of the various disciplines responsible for the activities in each phase, the critical engineering and procurement activities, and the major elements of construction by work area.
[58] Upstream Capacity Charge means the contribution required from an applicant requesting an increase in access to Capacity on Common Assets. The Upstream Capacity Charge cannot be less than zero.
[59] The study is funded by the applicant.

magnitude of the load requests will not be known until the Facilities Studies (Stage 3) are completed for each region and interconnection agreements are established. It is expected that Stage 3 will be completed by year-end 2023. The extent to which resource builds are required to support the interconnection agreements may delay this timeline. As the load requests are advanced, sensitivity forecasts will continue to be developed for use in various planning studies.

4.5 Island Interconnected System Winter 2021–2022 Peak Demand

Weather conditions across the Island Interconnected System for the winter 2021–2022[60] were relatively mild compared to average, as weather conditions during the period were less severe than the historically measured average (P50)[61] conditions. The maximum peak demand for the Island Interconnected System for winter 2021–2022 occurred during the morning of February 16, 2022.

Table 5 provides the summarized coincident customer peak demands as experienced at the time of peak as well as the P50 and P90 expected coincident customer class demands for the winter peak period of 2021–2022 as forecast in the fall of 2021.

Table 5: Coincident Customer Peak Demands for Winter 2021–2022 Exclusive of Transmission Losses and Station Service Requirements (MW)[62]

	P50 Peak Demand Forecast	P90 Peak Demand Forecast	Actual[63] Peak Demand	Weather-Adjusted[64] Peak Demand[65]
Utility[66]	1,474	1,534	1,417	1,450
Industrial[67]	154	154	146	146
IIS[68] Coincident Customer Demand[69]	1,628	1,688	1,563	1,596

60 December 1, 2021 through March 31, 2022.
61 A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time (i.e., the average forecast). A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time.
62 Forecast as per "Reliability and Resource Adequacy Study – 2021 Update – Volume II: Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2021.
63 February 16, 2022 actual peak loads for time interval 0745 to 0800 hours; peak occurred at 0756 hours.
64 Weather adjustment is a process that adjusts actual peak outcomes to what would have happened under normal or average weather conditions. The weather adjustment is derived from Hydro's Newfoundland Power Native Peak Demand model and the results are extrapolated to adjust Hydro's Island Rural peak.
65 Weather-adjusted utility peak demand estimates are at average historical peak weather conditions.
66 The coincident demand of Newfoundland Power and Hydro Rural retail.
67 The coincident demand of Island Industrial customers.
68 Island Interconnected System ("IIS").
69 Island Interconnected System customer demand exclusive of transmission losses and station service.

The Island Interconnected System coincident customer demand that occurred during the February 16, 2022 system peak was less than the P50 forecast (average) due to milder than average weather conditions on the peak day. Hence the actual Utility and Industrial demands were lower than forecast.

5.0 Labrador-Island Link Reliability

The LIL transmission project is a 900 MW, 350 kV HVdc transmission line that runs 1,100 kilometres from the Muskrat Falls Hydroelectric Generating Facility in Labrador to the Soldiers Pond Terminal Station on the Avalon Peninsula. The line includes a 30-kilometre underwater segment beneath the Strait of Belle Isle. As of the filing of the 2022 Update, the LIL has been successfully tested and operated at 475 MW.

While power has flowed on the line intermittently since 2018, the LIL has met numerous challenges that have prevented the completion of commissioning activities. In consideration of this, assessments completed by Haldar & Associates Inc. ("Haldar & Associates"),[70] in combination with information provided in the Emergency Response and Restoration Plans,[71] three separate analyses were performed to assess the impact of LIL reliability on resource adequacy.

The results of the LIL reliability analyses are documented in Section 5.0 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update. An analysis of an extended LIL outage and the loss of the LIL as the first contingency (i.e., energy-only line) can be found in Sections 5.5 and 5.6. In addition, the viability and suitability of the Holyrood TGS as an interim solution for a "Bridging Period"[72] is addressed in Section 5.3.

[70] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021) and "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[71] The "Labrador-Island Link Overhead Transmission Line Emergency Response Plan – Winter 2020-2021," Nalcor Energy - Power Supply was filed as Attachment 1 to the "Near-Term Reliability Report," Newfoundland and Labrador Hydro, May 15, 2020. An update, "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021, was filed as Attachment 2 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[72] The Bridging Period is defined as the period from 2023 to 2030. Further information regarding the Bridging Period can be found in Section 5.2 of the "Study Methodology and Planning Criteria" included as part of the 2022 Update.

5.1 Software Reliability

Hydro continues to collaborate and focus efforts with GE Grid Solutions ("GE") to provide successful Full Function Bipole software. Hydro's HVdc specialists participate in the factory acceptance testing to confirm performance and approve the release of software. Findings are documented and submitted to the Newfoundland and Labrador System Operator ("NLSO") to permit the operation of new software on the power system for Static and Dynamic Commissioning and then Trial Operations. Findings from this process are also documented are submitted to the NLSO as a basis for the operation and capacity of the LIL. Any punchlist[73] items that do not result in operational risk will be resolved after Trial Operations. In accordance with the contract, GE has six months after Trial Operations to resolve all outstanding punchlist items and release a final version of software.

The LIL has been successfully energized and operated for a 30-day trial operation period, completed on May 1, 2021, albeit at low power.[74] The next Trial Operations period will assist in verifying components under continuous operation at a higher power level and is expected to start following Dynamic Commissioning in the fall of 2022. Trial Operations will be deemed successful after 30 consecutive days without a trip attributed to the HVdc system.

GE has communicated that they are committed to delivering fully functional bipole software. Once the LIL is operational with the Full Function Bipole software, it could require multiple years of operational experience before the reliability of the link is determined.

5.2 Structural Reliability

The LIL is a key driver of the reliability of the Island Interconnected System. In early 2020, Hydro commissioned Haldar & Associates to assess the structural reliability of the LIL considering the climatological conditions which could potentially result in an extended bipole outage.[75,]

[73] Punchlist items are a list of incomplete scope and/or deficiencies agreed between the contractor offering the equipment, system, or part system and the owner receiving the equipment, system, or part system.
[74] During the Trial Operations period, the LIL was operated at various power transfer levels based on grid conditions. Maximum power transfer during the period was 225 MW, as per the Interim Bipole Software testing requirements.
[75] For the purpose of this report, an extended bipole outage is defined as a forced outage that would result in the inability of the utility to supply customers with power via the LIL for multiple days.

The Haldar & Associates report, "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads" ("Original LIL Reliability Report"),[76] considered the LIL design with respect to CSA 22.3 No. 60826-10[77] and the overall likelihood of failure of the LIL with respect to both glaze[78] and rime[79] icing events. Scenarios not directly following the guidance of CSA 22.3 No. 60826-10 (such as effective line lengths and wind speedup) were also considered to provide a fully informed assessment. The Original LIL Reliability Report also included a qualitative review of local conditions based on past operational experience. As part of the Original LIL Reliability Report, LIL return periods were defined to be in the range of 1:72 to 1:160 years.[80,81] A revised reliability analysis ("Phase II LIL Reliability Report") that was based on more extreme loading considerations,[82] indicates an annual probability of full bipole failure of 10% and a return period of 1:10 years due to structural failure. Other outcomes include consideration of regional correlation[83] and line length where the return period could be as low as 1:6 years with an associated annual failure rate of 16%. [84]

In response to the Phase II LIL Reliability Report, Hydro authored the "Reliability and Resource Adequacy Study Review – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings" ("Additional Considerations Report"),[85] which provides a high-level summary and response to the findings.[86] In summary, Hydro agrees with the concepts presented with respect to weather monitoring and the potential for improved reliability of the LIL and will continue to

[76] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., rev. April 11, 2021 (originally issued March 10, 2021).
[77] CSA 22.3 No. 60826-10: "Design Criteria of Overhead Transmission Lines" is a national standard that specifies the loading and strength requirements of overhead lines derived from reliability-based design principles.
[78] Glaze icing refers to freezing rain.
[79] Rime ice refers to in-cloud icing that occurs at higher elevations.
[80] The basis of design for the LIL from an overhead line perspective was 1:50 years as per Hydro's operational experience and stated in the basis of design report, "Basis of Design," Nalcor Energy – Lower Churchill Project, October 4, 2012, <https://www.muskratfallsinquiry.ca/files/P-04267.pdf>
[81] Return period, also known as recurrence interval, is an estimate of the likelihood of a climatological event to occur. It is usually used for risk analysis (e.g., to design structures to withstand an event with a certain return period).
[82] These extreme loading considerations are outside of the guidance of the CSA 22.3 No. 60826-10.
[83] Regional correlation refers to the frequency of storm impacts on multiple subsections of the LIL.
[84] Regional correlation and line length considerations are outside of the guidance of the CSA 22.3 No. 60826-10.
[85] "Reliability and Resource Adequacy Study Review – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.
[86] The "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021 includes the "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc., December 21, 2021 (Attachment 1) and updates to the "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021 (Attachment 2), including the "Emergency Response Timeline Report Labrador Island Link," Locke's Electrical Limited, November 25, 2021 (Appendix B).

take action on this initiative based on the recommendations put forth in the Additional Considerations Report. However, it is Hydro's view that the exact extreme combined wind and ice load scenarios suggested by Haldar & Associates are not supported by historical data at this time. In response, Hydro has invested in the installation of weather stations in these zones to monitor these conditions to inform if any structural investments are required. Further, concepts relating to line length and regional correlation have not been widely validated or utilized within the utility industry. As such, Hydro does not have a basis to definitively accept such considerations; rather, Hydro will consider the impacts of a significant failure of the LIL, independent of the frequency of such an event occurring, as part of the extended LIL outage analysis discussed in Section 5.5. The sensitivities associated with this wide range of reliability considerations will be assessed as part of the reliability analysis of the system.

Through operational experience and strategic monitoring, Hydro will also gain an understanding of the effectiveness of potential investments to upgrade LIL structures. Such investments (i.e., weather monitoring stations) have and will be made in consideration of risk and value-based assessments that will be better informed of other critical factors that impact system reliability, including response times for emergency repairs. While comprehensive structural upgrades to increase the reliability of the full transmission line based on extreme meteorological conditions would almost certainly be cost prohibitive, consideration will be given when Hydro has gathered more data from weather monitoring stations located at specific structures identified in the analysis performed by Haldar & Associates. It is noted that the findings associated with the more extreme value assessment completed by Haldar & Associates would impact approximately 2% of LIL structures, which allows for a strategic approach, as the identified structures can be monitored and upgraded as required. As discussed, upgrades to address local combined wind and ice and wind speedup effects could be performed to appreciably impact the reliability of the transmission line if deemed necessary.

The "Emergency Response & Restoration Planning – Labrador-Island Link Overland Transmission" ("Emergency Response and Restoration Plan")[87] was included as Attachment 2 to the Additional Considerations Report. A third-party analysis is included in the Emergency Response and Restoration Plan

[87] "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021, filed as Attachment 2 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.

that assesses the timelines for power restoration for seven possible failure scenarios.[88] This analysis resulted in a similar estimated restoration time of three to six weeks, depending on the scenario, including logistics and line location.[89]

Hydro is using the output of the assessments completed by Haldar & Associates in combination with the information provided in the Emergency Response and Restoration Plan to further inform the 2022 Update. These components have served as the basis for considering the potential length of a significant outage of the LIL. Therefore, Hydro updated the extended LIL outage analysis from three weeks, as reported in the 2019 Update, to six weeks to align with the third-party assessment and Hydro's own determination of estimated time to restore power.[90] Information on the three different approaches used to study the impact of the LIL bipole reliability on resource adequacy can be found in Section 4.2.1 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update.

5.3 Holyrood Thermal Generating Station as Standby Option

The Holyrood TGS Units 1 and 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. The three units combined provide a total firm capacity of 490 MW. It has been Hydro's intention to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls Project Assets. During this period of standby, the Holyrood TGS units would be fully available for generation. In correspondence dated February 4, 2022,[91] Hydro advised the Board of an extension to the operations of the Holyrood TGS as a generating facility to March 31, 2024, at which point Units 1 and 2 would be retired, and Unit 3 would continue to operate as a synchronous condenser.

Through the *Reliability and Resource Adequacy Study Review* technical conference presentation on November 30, 2020, as well as subsequent correspondence to the Board, Hydro advised of its intention to undertake an assessment to determine the potential long-term viability of the Holyrood TGS. The purpose of this assessment was to inform Hydro's options for incremental generation, should it be determined that

[88] "Emergency Response & Restoration Planning – Labrador-Island Link – Overland Transmission," Newfoundland and Labrador Hydro, December 15, 2021, app. B.
[89] "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021, att. 2, sec. 5.2.
[90] In 2019, Hydro undertook an exercise to determine the estimated time to restore power based on the location of the failure. At the time, it was determined that restoration could take up to seven weeks, depending on the circumstances of the failure.
[91] "*Reliability and Resource Adequacy Study Review* – Additional Considerations of the Labrador-Island Reliability Assessment and Outcomes of the Failure Investigations Findings – Additional Information," Newfoundland and Labrador Hydro, February 4, 2022, p. 7.

additional backup generation is required to support the provision of least-cost, reliable service. Hydro engaged Hatch Ltd. ("Hatch") to conduct the assessment. Hatch's assessment concluded in early 2022 and was filed with the Board on March 31, 2022.[92]

The scope of the assessment consisted of two components:

1) A condition assessment as well as an assessment of the remaining life of the existing assets of the Holyrood TGS; and

2) A study to determine the viability and costs associated with the continued operation of the Holyrood TGS, either in full generation mode or as a standby generating resource.

Through this assessment, Hatch concluded that the Holyrood TGS is in generally good operating condition and with sustained capital investment, the Holyrood TGS provides a viable supply option in full generation mode or as a standby generating resource under various recall scenarios[93] through 2030, at which point further assessment would be required to inform the viability of operation beyond 2030.

As noted in Section 5.0 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update, Hydro has established the need for on-Island backup generation to support the LIL until new resources are added. In addition, there is a need for reliable backup generation to address the capacity shortfall on the Island Interconnected System in the event of an extended (i.e., up to six weeks) LIL outage.[94] To that end, Hydro has considered Hatch's assessment in this 2022 Update analysis, supplemented with Hydro's reliability analysis, to study the role of the Holyrood TGS in meeting Newfoundland and Labrador Interconnected System resource requirements.

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[92] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022.
[93] Recall time refers to the time required to synchronize generating units to the grid from the time the unit is called upon. Hatch assessed four recall scenarios ranging from under 4 hours to 30 hours. Reduced recall time requires capital modifications to plant infrastructure.
[94] Results on the prolonged loss of the LIL are available in Section 5.5.

5.3.1 Unit Reliability Analysis

The Holyrood TGS has been historically operated as a base-load generation facility, with all three units generating during the winter operating season. In addition to operating as a generator, Unit 3 has also operated as a synchronous condenser during the summer months and shoulder periods.[95,96] As a source of capacity to be utilized in the event of a capacity shortfall due to an extended outage of the LIL, the reliability of the Holyrood TGS must be assessed in the context of its ability to bring units online quickly as well as its ability to operate reliably and at sufficient capacity for a six-week period when called upon.

Historically, forced outage rates for the three units at the Holyrood TGS have been reported using the DAFOR metric,[97] which is predominately used for units that operate in a continuous (base-load) capacity. When considering standby or peaking operations of units at the Holyrood TGS, DAFOR is no longer the most appropriate measure of forced outage rate. Common standby metrics include UFOP[98] and DAUFOP,[99] which are currently used for Hydro's gas turbine fleet. When considering standby or peaking operations of units at the Holyrood TGS, DAUFOP is a more appropriate measure given the frequency of deratings historically experienced by these units. The operational data used to produce the DAFOR measure can also be used to establish a historical record of the performance of these assets when considering operations in a standby or peaking capacity.

Unit Reliability: Base-Load Operation

All operational data for the period January 1, 1993[100] to May 1, 2022[101] was included in the analysis. Hydro analyzed the average DAUFOP[102] performance of each unit and the total plant for the entire calendar year. In addition, the average DAUFOP performance of each unit was analyzed for the period between April 1 and November 1 each year to better represent the reliability of the Holyrood TGS in standby operation. A

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[95] Converting Unit 3 to synchronous condenser capability provides reactive power support to the Island Interconnected System and helps regulate system voltage on the Avalon Peninsula.
[96] Unit 3 requires 24 to 36 working hours to convert from synchronous condense mode to generate mode.
[97] Derated Adjusted Forced Outage Rate ("DAFOR") measures the percentage of time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages.
[98] Utilization Forced Outage Probability ("UFOP") is the probability that a generating unit will not be available due to forced outages when there is demand on the unit to generate.
[99] Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") is the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
[100] Accurate operational data for the Holyrood TGS is not available prior to January 1, 1993.
[101] The analysis included the annual period from 1993 to 2021, in addition to January 1, 2022 to May 1, 2022 to include the most recent winter period.
[102] Given the intended reduction number of operating hours, DAUFOP remains a more appropriate measure than DAFOR that has historically been used.

summary of the results is included in the sections that follow; additional details are included in Attachment 4 to the "Long-Tem Resource Plan" included as part of the 2022 Update.

Historical Average DAUFOP (January 1 – December 31)

To assess the overall DAUFOP performance of the Holyrood TGS, Hydro used historical data to calculate the annual DAUFOP. The overall average, five-year average, and ten-year average for each unit was 12.7%, 15.6%, and 14.8%, respectively. Average DAUFOP by unit and for the total Holyrood TGS is provided in Table 6.

Table 6: Average DAUFOP Performance (January 1 to December 31)

	Overall Average (1993–2021)	5-Year Average (2017–2021)	10-Year Average (2012–2021)
Holyrood Unit 1	14.56%	18.04%	21.81%
Holyrood Unit 2	11.89%	15.65%	12.60%
Holyrood Unit 3	11.66%	13.17%	9.87%
Total Holyrood TGS	**12.70%**	**15.62%**	**14.76%**

Historical Average DAUFOP (April 1 – November 1)

Hydro's assessment of DAUFOP for the period January 1 to December 31 includes significant periods when the Holyrood TGS units were base loaded during the winter operating season. To better represent the Holyrood TGS' performance as a standby plant, Hydro used historical data to calculate DAUFOP instead of DAFOR for the period between April 1 and November 1 each year. This period was selected for analysis to remove the bulk of the operating hours to better resemble what operations would look like in a standby operating scenario versus how the Holyrood TGS normally operates during the winter months as base load. The average DAUFOP considering the period between April 1 and November 1 better represents the reliability of the Holyrood TGS in standby operation.

The five- and ten-year averages for each unit for the period between April 1 and November 1 were determined to be 24.6% and 21.7%, respectively. The average DAUFOP performance for the period April 1 to November 1 is presented in Table 7.

Table 7: Average DAUFOP Performance (April 1 to November 1)

	5-Year Average (2017–2021)	10-Year Average (2012–2021)
Holyrood Unit 1	26.40%	27.93%
Holyrood Unit 2	20.63%	16.04%
Holyrood Unit 3	26.79%	21.18%
Total Holyrood TGS	**24.61%**	**21.72%**

Unit Reliability: Standby Operation

Lastly, to better understand the starting performance of the units at Holyrood TGS, the operational data from January 1, 1993 to May 1, 2022[103] was reviewed and each attempted start was identified as well as its outcome when considering a required run time of six weeks of operation. Historical starting failure data for all three units at the Holyrood TGS was reviewed. Restoration times following the failed starts range from hours to upwards of 12 days; however, the average restoration time was approximately 3 days. Hydro's analysis determined that the failed start rates for the period January 1, 2012 to May 1, 2022 for Units 1, 2, and 3 were 51.2%, 50.0%, and 44.6%, respectively.[104,105]

To ensure sufficient generation is available on-Island in the event of an extended bipole LIL outage, on-Island generation must operate reliably. Standby generation must be dispatchable and able to synchronize with the grid quickly, ideally with a recall time within 10 minutes. The Holyrood TGS, as designed, is not ideally configured to meet these requirements. It was originally designed to be base loaded (i.e., limited starts, limited cycling), with a unit recall in excess of 24 hours.

In addition to reducing recall time, Hydro must also improve the reliability of the units during start-up. With a typical start-up success rate of only approximately 50% and an average restoration time of three days following an unsuccessful start, resulting in the average time required to successfully recall a unit ranging from approximately two to three days,[106] Hydro does not consider the Holyrood TGS suitable for operation as a standby generating facility to be called upon in the event of an unplanned LIL outage, as it

[103] The analysis included the annual period from 1993 to 2021, in addition to January 1, 2022 to May 1, 2022, to include the most recent winter period.
[104] Hydro completed the same analysis over a three-week period. The analysis determined that the failed start rates for the period January 1, 2012 to May 1, 2022 for Units 1, 2, and 3 were 47.2%, 44.2%, and 44.6%, respectively.
[105] For the purposes of this analysis, a successful unit start was defined as a start at full capacity or derated, without a trip for six weeks following successful synchronization.
[106] Average successful recall time = 3 Days × 50% + Unit Recall Time

is anticipated that even under the fastest recall scenario analyzed, there is a high probability of issues during start-up, delaying synchronization of the units by several days. Hydro does not expect that capital upgrades to reduce the recall time of the units would materially improve the reliability of the units during start-up.

5.3.2 Recommendation

During the early operational stages of the LIL, the three Holyrood units will be base loaded to ensure the availability of capacity for the power system. This will remain the case as Hydro continues to monitor LIL performance and reliability. If the LIL is found to perform well for an extended period and system conditions permit, Hydro would have the opportunity to strategically remove the Holyrood TGS units from service.

As presented herein, there are reliability concerns associated with the operation of the units at the Holyrood TGS in a standby capacity. However, there are significant fuel costs associated with the continued base-loaded operation of the three units. Hydro will therefore investigate operational strategies to optimize the dispatch of the units to manage start-up challenges while minimizing cost.

Based on the information provided herein, all three Holyrood TGS units are to remain available for operation until an adequate replacement can be put in service. A DAUFOP of approximately 20% will be used for resource adequacy planning purposes. Hydro will continue to analyze the operational data to ensure that forced outage rate assumptions for the Holyrood TGS are appropriate.

Capital and Operating Costs

As part of its assessment, Hatch provided estimated capital and operating costs for the continued operation of the Holyrood TGS. The capital costs for the period 2024–2030 are provided in Table 8. Hydro would continually assess the current context and consider opportunities to reduce capital expenditures, considering the needs of the system and LIL reliability assumptions on an annual basis for capital planning purposes. A detailed capital plan was provided within the Hatch assessment.[107]

[107] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022, att. 3, app. D.

Table 8: Holyrood TGS Capital Costs for Extended Base-Load Operation ($000)

	2024	2025	2026	2027	2028	2029	2030	Total
Unit 1	6,433	3,333	3,500	3,800	4,200	12,394	3,667	**37,327**
Unit 2	5,033	3,333	4,300	3,500	3,500	3,667	3,667	**27,000**
Unit 3	4,399	13,097	8,777	6,600	5,200	7,667	3,667	**49,407**
Balance of Plant	10,452	6,109	2,500	3,850	1,111	1,000	1,250	**26,272**
Total Capital	**26,317**	**25,872**	**19,077**	**17,750**	**14,011**	**24,728**	**12,251**	**140,006**

The estimated operating costs for base-load operation, including fuel costs, for the period 2024–2030 are provided in Table 9.

Table 9: Holyrood TGS Operating Costs for Extended Base-Load Operation ($000)

	2024	2025	2026	2027	2028	2029	2030	Total
Operating Cost	25,147	25,147	25,147	25,147	25,147	25,147	25,147	**176,029**
Fuel Cost	101,000	98,000	97,000	98,000	99,000	101,000	103,000	**697,000**

While Hydro requires the continued availability of the Holyrood TGS, it is recognized that there is a need to accelerate the integration of new generation to reduce the dependency and costs of relying on the Holyrood TGS.

5.4 Hardwoods and Stephenville Gas Turbines as Standby Option

The Stephenville Gas Turbine consists of two 25 MW gas generators that were commissioned in 1975. The Hardwoods Gas Turbine consists of two 25 MW gas generators that were commissioned in 1976. Each facility provides 50 MW of firm capacity to the system. These units were designed to operate in either generation mode, to meet peak and emergency power requirements, or synchronous condense mode, to provide voltage support to the Island Interconnected System. In its May 2022 Near-Term Reliability Report,[108] Hydro communicated to the Board that the Stephenville Gas Turbine is required to remain in service until the power transformer at the Bottom Brook Terminal Station is in service to address the backup supply for the area. Hydro has committed to keeping the Hardwoods and Stephenville Gas Turbines in service until the LIL is proven reliable. As such, they will both continue to be available through the next two winter seasons.

[108] "Reliability and Resource Adequacy Study - 2022 Update - Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 16, 2022.

Subsequent to the May 2022 Near-Term Reliability Report, Hydro’s current generation shortfall and reliability analysis supports the retirement of the Stephenville Gas Turbine in 2024, at which point the backup supply for the area served by the Stephenville Gas Turbine will have been addressed by the addition of a 230/66 kV, 40/53.3/66.7 MVA power transformer at the Bottom Brook Terminal Station and subsequent reconfiguration at the Stephenville Terminal Station. A project to complete these modifications was included in Hydro's 2021 Capital Budget Application.[109]

Hydro’s current analysis also recommends that the Hardwoods Gas Turbine remain in service until 2030 to support the Island Interconnected System in the event of a LIL outage or until such time that sufficient alternative generation is commissioned and both the Holyrood TGS and Hardwoods Gas Turbine are no longer required to support generation reserves in a contingency scenario. Operating hours and generation at the Hardwoods Gas Turbine have decreased materially from levels observed in 2014 through 2018 and asset availability at this facility is much improved over levels previously observed.[110] Following its retirement, Hydro intends to decommission the Stephenville Gas Turbine and utilize its components as spares to support the reliable operation of the Hardwoods Gas Turbine.

The estimated annualized capital cost for continued operation of the Hardwoods GT to 2030 is approximately $2.5 million. The estimated annual operating costs, excluding fuel, are $450,000.

5.5 Shortfall Analysis: Prolonged Loss of the Labrador-Island Link

With the introduction of the Muskrat Falls Hydroelectric Generating Facility, a large portion of the generation serving the Island load is located in Labrador. The reliability of the LIL is a key driver of the reliability of the Island Interconnected System. Currently, concerns remain regarding reliance on the LIL to reliably supply the Island Interconnected System.

As noted in Section 5.1, Hydro continues to collaborate and focus efforts with GE to provide Full Function Bipole software. Hydro also recognizes the possibility of an extended outage on the LIL (i.e., six weeks), due to emergency response time in the event of a structural failure, as discussed in Section 5.2.

[109] “2021 Capital Budget Application,” Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020), vol. II, tab 14.
[110] This reduction in the requirement to operate is primarily attributed to the availability of the Maritime Link and Hydro’s ability to use a portion of the capacity available under its Capacity Assistance Agreement with Corner Brook Pulp and Paper Limited (“CBPP”) as ten-minute reserve.

In the 2018 Filing, an extended bipole outage was considered a very low probability, high consequence event. Since then, studies such as the Original LIL Reliability Report and the Phase II LIL Reliability Report[111] indicate that the probability is much greater than originally thought. While Hydro does not have a basis to definitively accept these findings, planning to mitigate the consequences of such a prolonged outage is essential.

Hydro recognizes that the Board and other stakeholders wish to better understand the implications of a prolonged LIL outage. The sections that follow discuss the effects of an extended LIL outage on the Island Interconnected System and a potential solution to mitigate such effects.

5.5.1 Assessment of a Six-Week LIL Bipole Outage

To inform a risk-based analysis of such implications, in addition to modelling the LIL with its anticipated availability, an extended LIL outage scenario was also considered. The extended outage scenario assumes the LIL is unavailable for six weeks during the coldest period of the year (i.e., January and February) to quantify the impact on system reliability. The LIL extended outage is intended to simulate an icing situation that causes a tower collapse in a remote segment of the transmission line; however, the extended outage scenario could generally apply to any prolonged outage event. It is important to note that there is a risk that such an outage could have a duration potentially lasting longer than six weeks.

Chart 5 and Chart 6 provide an indication of the resulting supply shortfall of a six-week outage during high-demand periods for the test years 2026 and 2032. The analysis was completed on a probabilistic basis[112] and depicted in 50th and 90th percentiles representing average and severe scenarios. The amount of shortfall depicted in the graphs and summarized in the tables represents the amount of load shedding required to restore to a minimum regulating reserve of 70 MW, as discussed in Section 3.2.1 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update.

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

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[111] The Phase II LIL Reliability Report is considered to be the "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Phase II," Haldar & Associates Inc. December 12, 2021, filed as Attachment 1 to the "Reliability and Resource Adequacy Study – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021.

[112] The probabilistic analysis looks at variations in weather-driven loads, unit outage profiles, and renewable generation

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

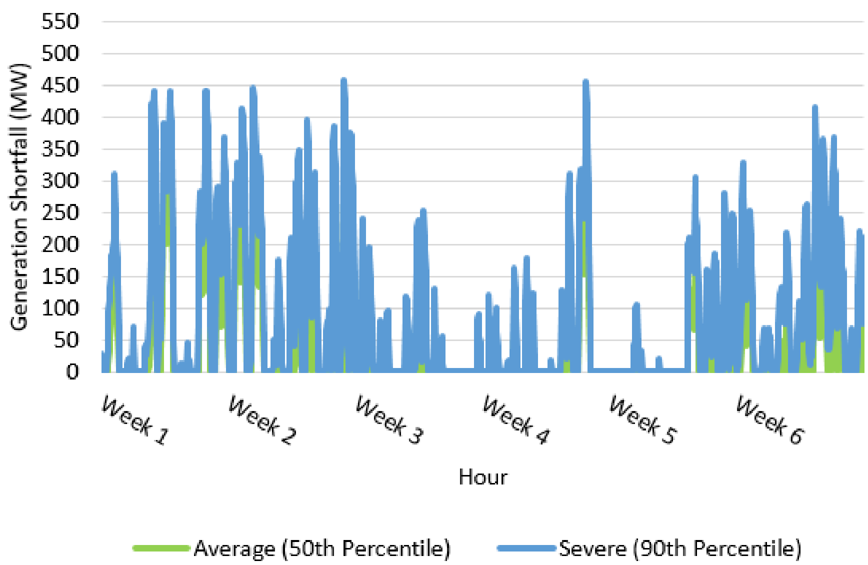

Chart 5: Forecast Daily Shortfall with the LIL Unavailable for a Six-Week Period in 2026

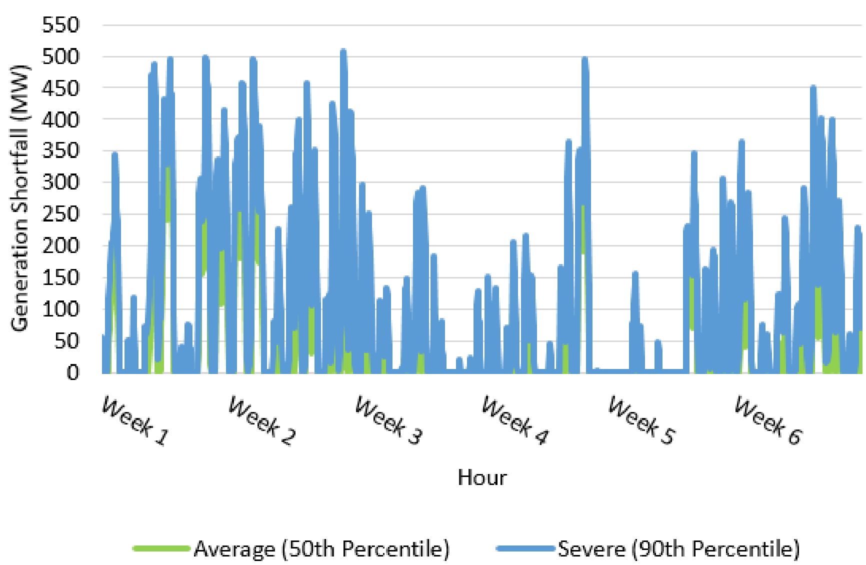

Chart 6: Forecast Daily Shortfall with the LIL Unavailable for a Six-Week Period in 2032

Chart 5 and Chart 6 highlight that varying degrees of rotating customer outages could be expected if a six-week outage were to occur. These rotating outages could be expected for the majority of the six-week period with very few days throughout the period with minimal exposure to loss of load events. As expected, as load is forecasted to grow between the test years of 2026 and 2032, the amount of generation shortfall also increases. In the test year 2026, customers can expect an average of 385 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 460 MW. In the test year 2032, customers can expect an average of 427 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 508 MW.

Chart 7 and Chart 8 show the exposure for unserved energy if the outage were to occur on the peak day in the study years 2026 and 2032. The higher the scenario percentile, the larger the expected level of unserved energy.

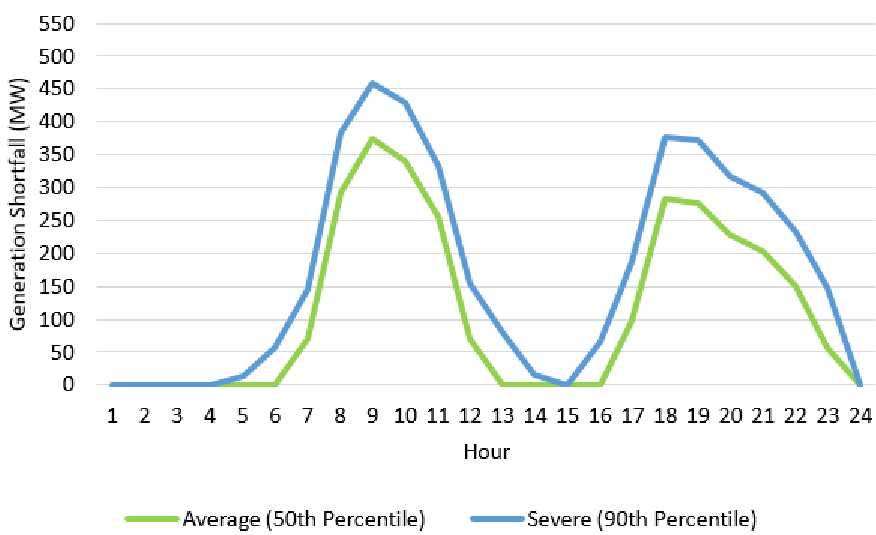

Chart 7: Forecast Shortfall on a Typical Peak Day with the LIL Unavailable (January 2026)

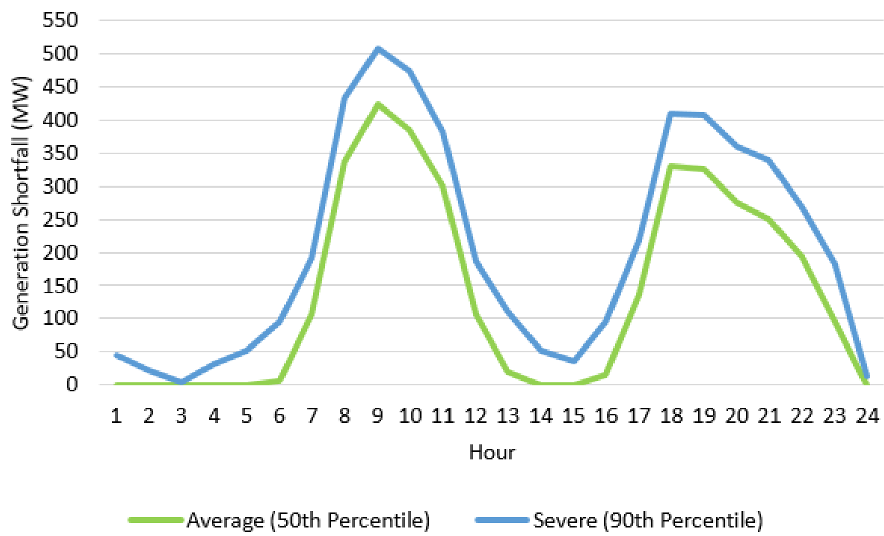

Chart 8: Forecast Shortfall on a Typical Peak Day with the LIL Unavailable (January 2032)

5.5.2 Impact of Incremental Generation

This section includes an assessment of the impact of extending existing assets (i.e., the Holyrood TGS and the Hardwoods Gas Turbines) through the Bridging Period and incremental generation additions on the customer load interruptions in the "Future Period."[113]

Incremental generating sources[114] considered as part of the analysis include:

- Continued operation of the Holyrood TGS only through 2030;
- Continued operation of the Holyrood TGS and the Hardwoods Gas Turbine through 2030;
- Addition of the 154 MW Bay d'Espoir Unit 8[115] by 2032;
- Addition of the 154 MW Bay d'Espoir Unit 8 + 100 MW by 2032;
- Addition of the 154 MW Bay d'Espoir Unit 8 + 200 MW by 2032; and
- Addition of the 154 MW Bay d'Espoir Unit 8 + 300 MW by 2032.

The reduction in customer outages expected by extending the Holyrood TGS only and both the Holyrood TGS and the Hardwoods Gas Turbines are shown in Chart 9 and Chart 10, respectively.[116] Results are

[113] The "Future Period" is defined as the period beyond 2030 (the Bridging Period).
[114] The incremental generation amounts of 100 MW, 200 MW, and 300 MW are being used as general capacity placeholders and are not representative of a specified resource option.
[115] Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility.
[116] Assumes the Stephenville Gas Turbine is retired on March 31, 2024.

further summarized in Table 10 and Table 11. The amount of shortfall depicted in the graphs and summarized in the tables represents the amount of load shedding required to restore to a minimum regulating reserve of 70 MW as discussed in Section 3.2.1 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update.

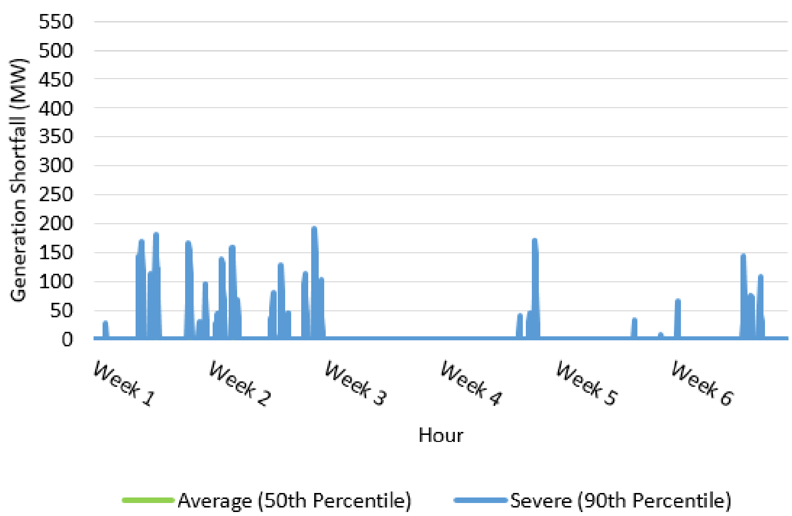

Chart 9: Shortfall Remaining with Holyrood TGS In-Service in 2026

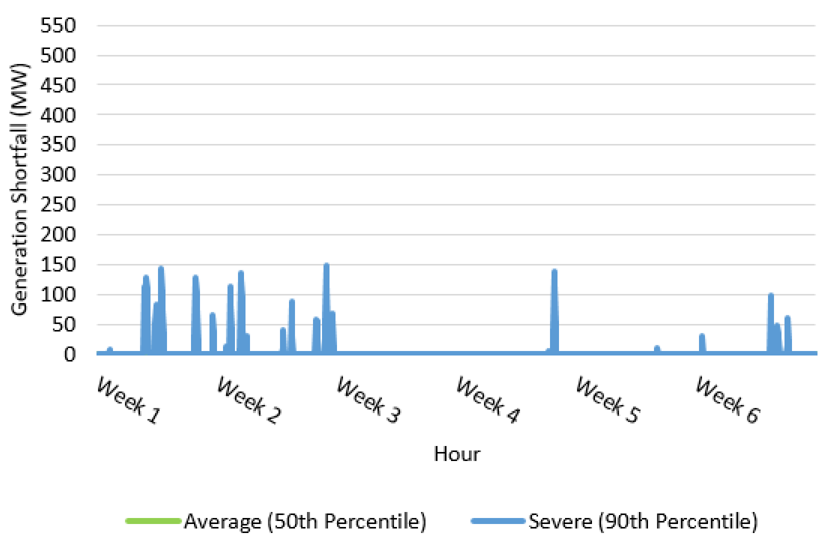

Chart 10: Shortfall Remaining with Holyrood TGS and Hardwoods GT In-Service in 2026

Chart 9 represents the capacity shortfall remaining in during the six-week period with the Holyrood TGS in service and the LIL offline. The level of shortfall is estimated using the base-case load forecast in the test year 2026. In this scenario, customers can expect an average of 29 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 192 MW. Chart 10 includes both the Holyrood TGS and the Hardwoods Gas Turbine in service during the six-week LIL outage. In this scenario, it is estimated that customers can expect an average of 20 hours of unserved energy over a six-week period, with the highest anticipated shortfall estimated to be 150 MW.

Table 10: Summary of Anticipated Shortfalls with Incremental Generation in 2026

Case	EUE[117] (GWh)	Hours of Generation Shortfall
No Incremental Generation	55.4	385
Extension of Holyrood TGS	2.3	29
Extension of Holyrood TGS + Hardwoods GT	1.6	20

Table 11: Summary of Peak Shortfall with Incremental Generation in 2026 (MW)[118]

Shortfall	Average Case (50th Percentile)	Severe Case (90th Percentile)
No Incremental Generation	374	460
Extension of Holyrood TGS	15	192
Extension of Holyrood TGS + Hardwoods Gas Turbine	0	150

The changes in shortfall made possible with the addition of Bay d'Espoir Unit 8 in combination with additional generation in increments of 100 MW up to approximately 450 MW of additional generation can be observed in Chart 11 to Chart 14. Results are further summarized in Table 12 and Table 13. The level of shortfall is estimated using the base-case load forecast in the test year 2032; therefore, the Holyrood TGS and the Hardwoods Gas Turbine are assumed retired. The amount of shortfall depicted in the graphs and summarized in the tables represents the amount of load shedding required to restore to a minimum regulating reserve of 70 MW as discussed in Section 3.2.1 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update.

[117] Expected Unserved Energy ("EUE") is the expected amount of demand that is unserved per year due to demand exceeding generating capacity.
[118] The 50th percentile case presented in Table 11 indicates shortfalls that are not as evident in the charts due to the scale of the graph and the overlay of the 90th percentile case. However, the totals summarized in Table 11 are direct outputs from the same data used in the charts.

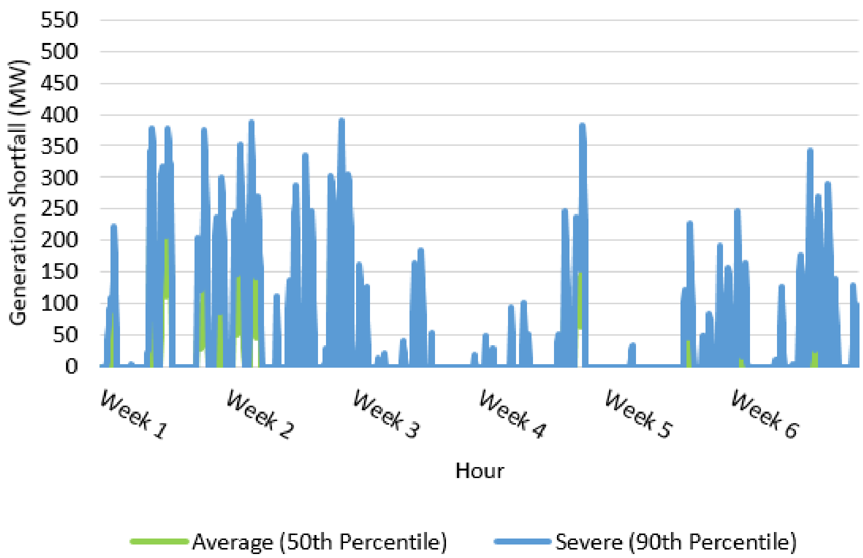

Chart 11: Shortfall Remaining with Addition of Bay d'Espoir Unit 8 in 2032

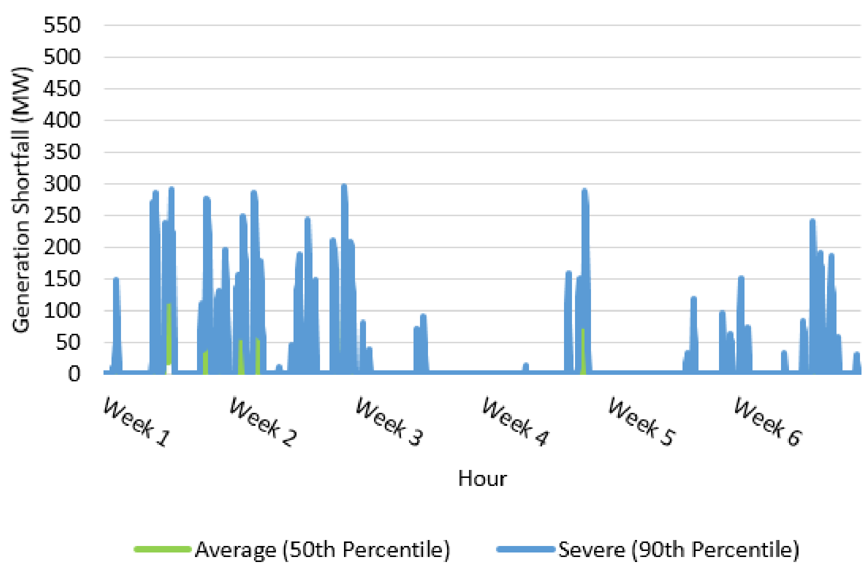

Chart 12: Shortfall Remaining with Addition of Bay d'Espoir Unit 8 and 100 MW of Additional Capacity in 2032

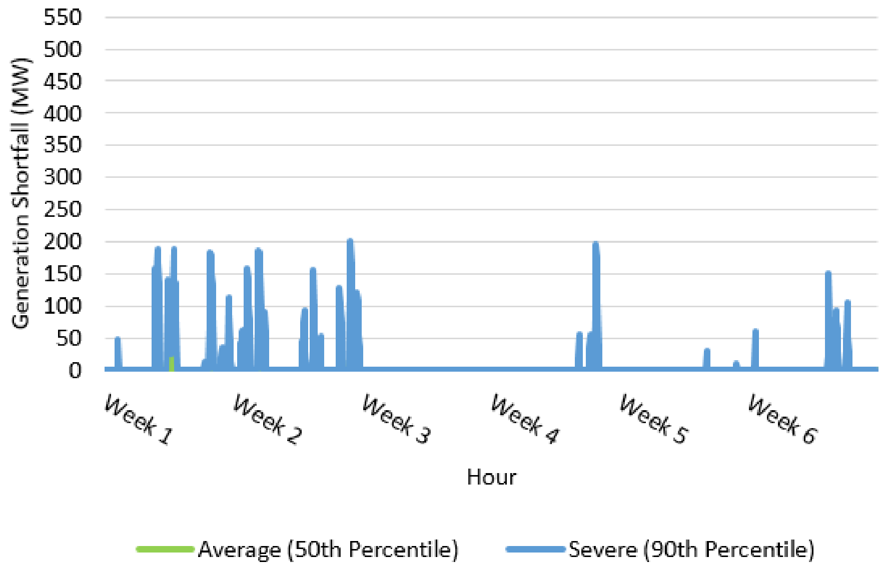

Chart 13: Shortfall Remaining with Addition of Bay d'Espoir Unit 8 and 200 MW of Additional Capacity in 2032

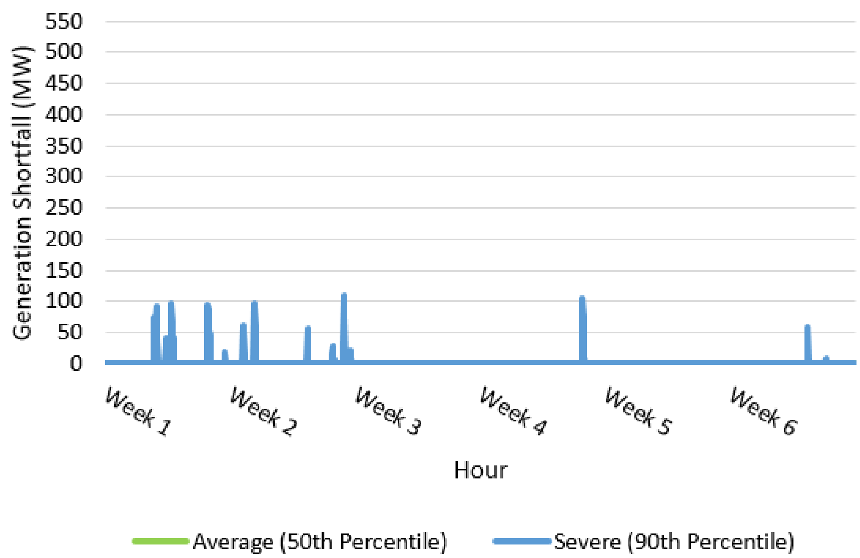

Chart 14: Shortfall Remaining with Addition of Bay d'Espoir Unit 8 and 300 MW of Additional Capacity in 2032

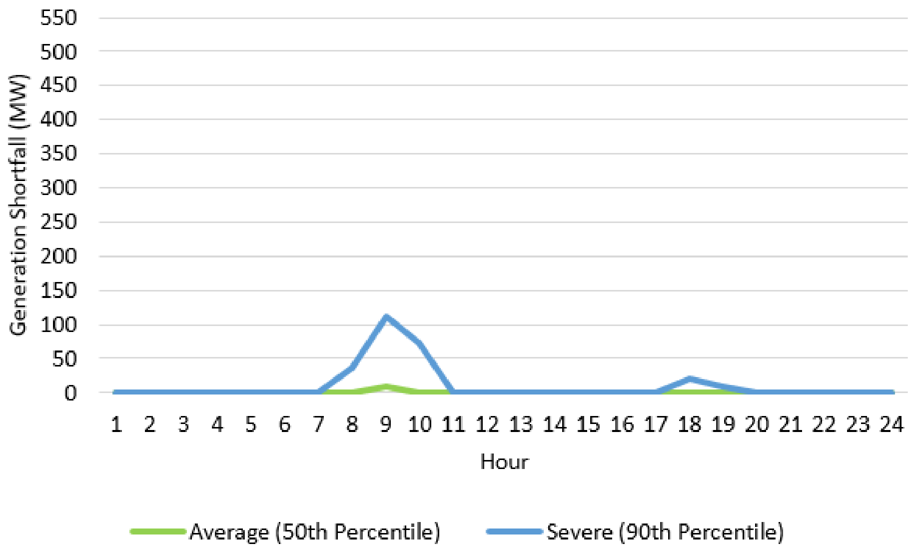

Chart 15: Forecast Shortfall on Peak Day with 450 MW of New Generation (January 2032)

A summary of the results of the changes in shortfall made possible with the addition of Bay d'Espoir Unit 8 in combination with additional generation follows:

- **Addition of 154 MW Bay d'Espoir Unit 8**: In this scenario, customers can expect an average of 230 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 389 MW.
- **Addition of 154 MW Bay d'Espoir Unit 8 + 100 MW:** In this scenario, customers can expect an average of 126 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 297 MW.
- **Addition of 154 MW Bay d'Espoir Unit 8 + 200 MW:** In this scenario, customers can expect an average of 54 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 203 MW.
- **Addition of 154 MW Bay d'Espoir Unit 8 + 300 MW:** In this scenario, customers can expect an average of 14 hours of unserved energy within a six-week period. The rotating outages will occur primarily during peak hours, with the highest anticipated shortfall estimated to be 111 MW.

Table 12: Summary of Anticipated Shortfalls with Incremental Generation in 2032

Case	EUE (GWh)	Hours of Generation Shortfall
No Incremental Generation	68.4	427
+ Bay d'Espoir Unit 8	27.9	230
+ Bay d'Espoir Unit 8 and 100 MW	11.7	126
+ Bay d'Espoir Unit 8 and 200 MW	3.6	54
+ Bay d'Espoir Unit 8 and 300 MW	0.7	14

Table 13: Summary of Peak Shortfall with Incremental Generation in 2032 (MW)[119]

Shortfall	Average Case (50th Percentile)	Severe Case (90th Percentile)
No Incremental Generation	423	508
+ Bay d'Espoir Unit 8	291	389
+ Bay d'Espoir Unit 8 and 100 MW	198	297
+ Bay d'Espoir Unit 8 and 200 MW	100	203
+ Bay d'Espoir Unit 8 and 300 MW	9	111

The analysis summarized in Table 12 and Table 13 and Chart 11 to Chart 15 shows the extent to which incremental resources help to mitigate the potential for customer outages in the event of the prolonged loss of the LIL bipole. As shown in Chart 14 and Chart 15, the addition of 450 MW of new capacity, or Bay d'Espoir Unit 8 and 300 MW of new capacity, would be sufficient to minimize rotating outages to only the highest peak hours during the severe case (i.e., 90th percentile), and nearly all outages in the more typical or average conditions (i.e., 50th percentile).

This analysis depicts the customer outage impact during the coldest six weeks of the year, it is important to note that a LIL bipole outage can happen during any time of year. Outside of the peak load winter period, the severity and duration of the customer outages would be lower (i.e., better) than depicted in this analysis.

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[119] The 50th percentile case presented in Table 13 indicates shortfalls that are not as evident in the charts due to the scale of the graph and the overlay of the 90th percentile case. However, the totals summarized in Table 13 are direct outputs from the same data used in the charts.

Further analysis is needed to fully understand the reliability implications of an extended LIL outage. Hydro is committed to continuing to work with Newfoundland Power to determine what reasonable level of rotating outages, if any, could be maintained for an extended duration. Further, it is also necessary to better understand the implications this length of outage would have on reservoir storage by the end of a six-week outage. Hydro is committed to assessing this further in the 2023 Update. Hydro remains committed to working with the Board and stakeholders to contemplate how this extended outage scenario should be incorporated into Hydro's planning process, particularly in how best to balance cost and reliability.

5.5.3 Transmission Considerations for Incremental Generation

As presented in Section 4.2.1 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update, Hydro has adopted emergency planning criteria that would apply in the event of a LIL bipole outage. With these criteria in place, power flows up to 750 MW could be delivered from Bay d'Espoir to the Avalon Peninsula with the ac system intact. Therefore, there are no transmission constraints in this mode of operation that would prevent the delivery of available generation on the Island Interconnected System to load centres. This is also the case if Bay d'Espoir Unit 8 were added as an additional source of supply.

Based on the information provided herein and with the extended availability of generation from the Holyrood TGS and the Hardwoods Gas Turbine on the Avalon Peninsula, there is no appreciable reliability benefit of reinforcing of the ac transmission system at this time. As Hydro continues to work with stakeholders and advance long-term expansion plans, further analysis may be performed to assess if transmission system reinforcement is required to ensure that capacity from new sources of supply can be reliably delivered to customers in the event of a LIL bipole outage.

5.6 Additional Case: LIL as an Energy-Only Line

To provide a fulsome view of the importance of the LIL to Island Interconnected System reliability and the consequences of a prolonged bipole outage, an additional case is included in the 2022 Update to assess the loss of the LIL as the first contingency[120] (i.e., energy-only line). This analysis models a scenario where the loss of the LIL bipole is considered the first contingency rather than the loss of a single unit at the

[120] The first contingency is the unexpected failure or outage of a system's largest component, such as a generator or transmission line.

Muskrat Falls Hydroelectric Generating Facility. In the 2018 Filing and the 2019 Update, Hydro considered the first contingency loss to be the loss of a single unit at the Muskrat Falls Hydroelectric Generating Facility and the second contingency loss to be the loss of a second unit at the Muskrat Falls Hydroelectric Generating Facility.[121]

Following the same methodology that was used in determining the planning reserve margin in the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update, the resultant planning reserve margin for the Island Interconnected System equates to approximately 640 MW of new generation potentially required by 2032. This represents an additional 160 MW of incremental generation requirements compared to the long-term reliability criteria developed in Section 5.3 of the "Study Methodology and Proposed Planning Criteria" included as part of the 2022 Update. Chart 16 depicts the firm capacity in relation to the reserve margin requirement.

Assuming Bay d'Espoir Unit 7, with a capacity of 154 MW, is the largest unit on the Island Interconnected System; the second largest unit would be the Upper Salmon, with a capacity of 84 MW. This equates to operational reserve requirements of 196 MW.[122]

[121] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. I, sec. 3.3.1.2.
[122] If Bay d'Espoir Unit 8 were constructed, the operational reserve requirement would become 232 MW.

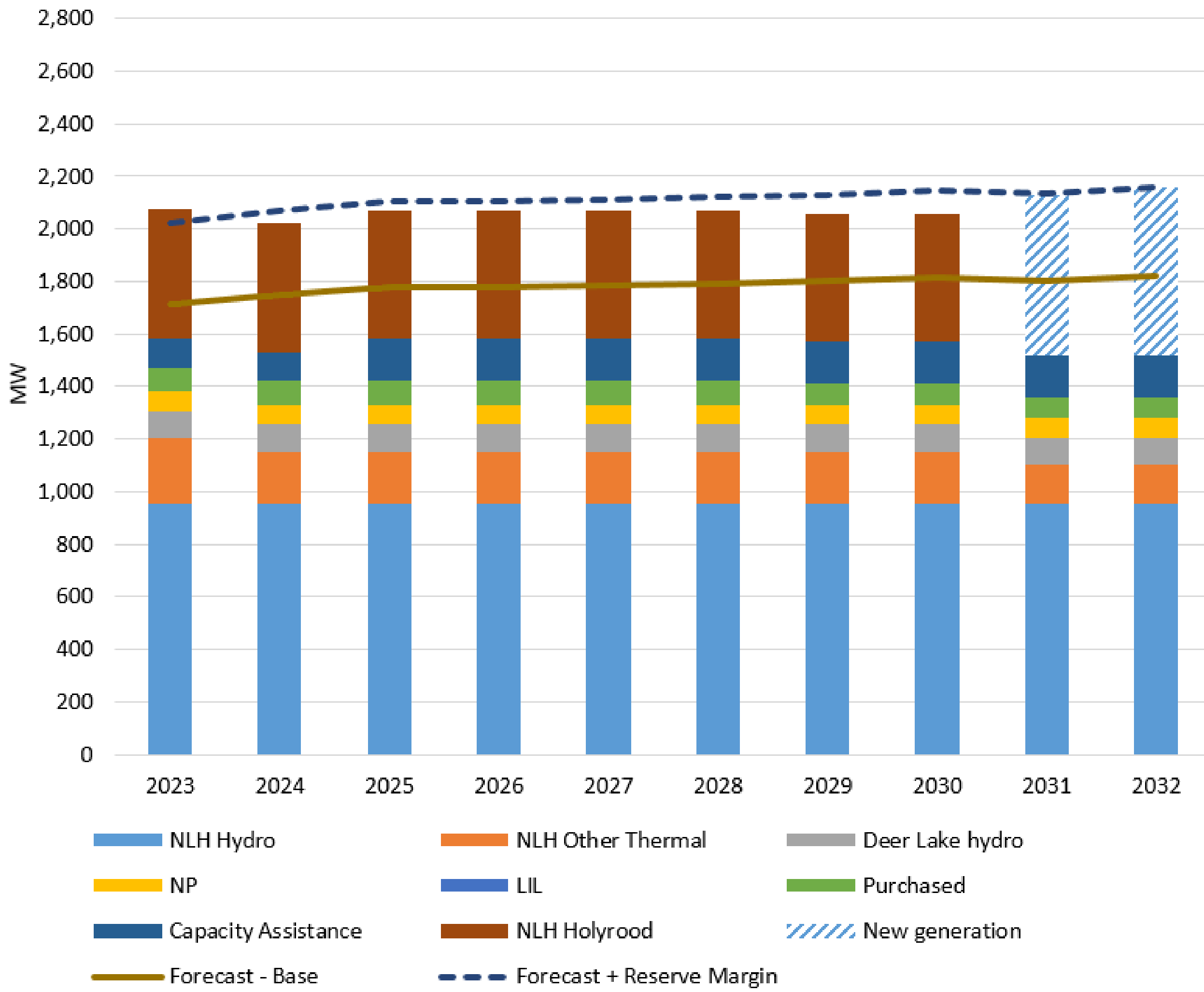

Chart 16: Firm Capacity versus Forecast Peak Demand[123,124,125]

Assessing LIL reliability in this way would result in significant incremental costs within the Island Interconnected System that must be balanced against the incremental reliability such investment would provide. Hydro has included this analysis as an additional case for information purposes; however, Hydro does not recommend this to be the defining reliability criteria at this time.

[123] Forecast peak demand in graph includes losses.
[124] Explanation of Legend: "NP" refers to Newfoundland Power hydro and thermal; "Deer Lake hydro" is modelled as the generation at Deer Lake and load out of CBPP; "Capacity Assistance" includes CBPP, Vale diesels, Vale curtailable, Memorial University of Newfoundland curtailable, and Newfoundland Power capacity assistance; "NLH Other Thermal" includes combustion turbines and diesels.
[125] Purchases reduce in 2031 due to the retirement of existing wind generation.

6.0 Energy Criteria

The Newfoundland and Labrador Interconnected System energy criterion is that the Newfoundland and Labrador Interconnected System should have sufficient generating capability to supply firm energy requirements with firm system capability.[126]

The ability to meet energy requirements is continually evaluated in consideration of historical inflow sequences and future customer and contracted requirements.[127,128] In the 2018 Filing and the 2019 Update, there were no violations of the energy criteria.

Table 14 outlines the Island and Labrador forecast load cases against the year in the study period that incremental energy requirements are identified.

Table 14: Forecasts versus Firm Energy Criterion[129]

Island and Labrador Load Scenario	Year of Incremental Energy Requirements
Base Island/Base Labrador	-
Base Island/High Labrador	2031
High Island/Base Labrador	-
High Island/High Labrador	2030

The Newfoundland and Labrador Interconnected System does not violate the energy criteria in the Base Island/Base Labrador scenario or the High Island/Base Labrador scenario. However, it does violate the energy criteria in the Base Island/High Labrador scenario by 2031 and in the High Island/High Labrador

126 On the Island, firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood TGS) is based on energy capability adjusted for maintenance and forced outages.
127 On the Island, from an operational perspective, minimum storage targets are developed annually to provide guidance in the reliable operation of Hydro's major reservoirs: Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage target is designed to show the minimum level of aggregate storage required such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, the Island Interconnected System load could still be met through the use of the available hydraulic storage, maximum generation at the Holyrood TGS while in service, and deliveries from the Muskrat Falls Hydroelectric Generating Facility over the LIL. Hydro's long-term critical dry sequence on the Island is defined as the hydraulic period occurring January 1959 to March 1962 (39 months). Other dry periods are also examined during the derivation to ensure that no other shorter-term historic dry sequence could result in insufficient storage.
128 In Labrador, the Recapture Block and the TwinCo Block provide firm energy to the Labrador Interconnected System.
129 This analysis assumes that the contracts with the Corner Brook Co-Generation, and Rattle Brook Hydroelectric Project expired, the St. Lawrence and Fermeuse wind projects end in 2029, and the Holyrood TGS retires in 2030. As well, it is assumed that energy can be transferred from Labrador to the Island via the LIL.

scenario by 2030. This analysis assumes no firm energy additions are added to the system during the test period.

Other than the construction of new generation or a reduction in customer load requirements to mitigate violations of the firm energy criterion, the opportunity to procure firm imports to supplement native supply could be considered and the planning criteria modified appropriately.[130] Further, in Labrador, there is also the option to supply future energy requirements with incremental energy from the Muskrat Falls Hydroelectric Generating Facility. The detailed firm energy analysis is included in Attachment 5 of the "Long-Term Resource Plan" included as part of the 2022 Update.

7.0 Long-Term Resource Plan

7.1 Expansion Resource Options Under Consideration[131]

The resource planning process identifies when incremental resources are required and which resource options fulfill Hydro's mandate of least-cost reliable supply by selecting the optimum resource mix from the portfolio of available resource options. Volume III, Section 4 of the 2018 Filing provides detailed information, including a brief project description, project-specific potential issues and risks, and a Class 5[132] estimate for the current portfolio of identified alternatives that may be considered to fulfill future resource requirements. Project costs have been escalated to 2022 dollars in support of this 2022 Update. Hydro's analysis considered the following resource options:

- Wind generation;
- Solar generation;
- Battery storage technology;
- Capacity assistance;
- Rate structure and Customer Demand Management;
- Market purchases;

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[130] Firm imports have not been included in this analysis.
[131] Details on resource options not considered are contained within "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 4.
[132] AACE Class 5 cost estimate is an estimate based on conceptual documentation. The accuracy of the cost estimate varies between less than 50% or more than 100% of the estimated cost.

- Hydroelectric Generation:
  - New facilities; and
  - Additional units at existing facilities; and
- Thermal Generation:
  - Simple cycle gas turbines.

7.1.1 Rate Structures and Customer Demand Management

While additional supply can be acquired to meet increased customer requirements, rate design and Customer Demand Management activities can also be undertaken to promote a reduction in customer demand and/or energy requirements.

Potential Electrification Impacts

Electrification has the potential to dramatically change the quantity and usage pattern of electricity by customers in Newfoundland and Labrador. Electrification of the transportation, space heating, and industrial sectors represents a significant opportunity for customers with risks that will require mitigation to avoid potential negative electricity system impacts.

Electrification presents the opportunity to utilize energy within the province to meet customer requirements as opposed to selling that same energy into export markets; this shift has the potential to provide additional funds for rate mitigation. Customer energy requirements are expected to increase materially over the next 20 years as a result of electrification. Transportation electrification (including the Government of Canada's intention to set a mandatory target for all new light-duty car and passenger trucks to be zero-emission by 2035),[133] customer conversions away from oil-fired space heating, and electrification of industrial processes will all contribute significantly to rate mitigation efforts through increased domestic energy sales.

However, unmanaged electrification can increase system costs beyond the additional revenue potential. Efficient rate design, energy-efficiency programming, and Customer Demand Management are all key to

[133] "Building a green economy: Government of Canada to require 100% of car and passenger truck sales be zero-emission by 2035 in Canada," Transport Canada, June 29, 2021, <https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html>

achieving beneficial electrification[134] and are therefore considered resource options in addition to utility generation and market purchases.

Dynamic Rates

One area of interest for Hydro is critical peak pricing, a rate structure whereby customers are motivated to reduce consumption during system peaks. Hydro-Québec is currently offering critical peak pricing to its customers.

Participants in the Hydro-Québec program can choose from one of two programs:

1) **Rate Flex:** Under the Rate Flex alternative, customers are offered a discount of 17% on the standard base rate during winter; however, electricity is priced materially higher than the standard base rate during peak demand events (52 cents per kWh).[135]
2) **Winter Credit Option**: The Winter Credit Option is marketed as a risk-free alternative to Rate Flex. The Winter Credit Option allows customers to receive a credit if they reduce their electricity consumption during peak demand events but does not offer a discount from the standard base rate during non-peak demand events. During a peak demand event, customers will receive a 52-cent credit for every kWh curtailed (i.e., not consumed compared to their usual energy use).[136]

During winter 2021–2022, Hydro-Québec had approximately 157,000 customers participating in critical peak pricing programs and was able to achieve an average reduction in electricity demand of 1 kW per customer per demand event. The cumulative impact of this program across the system was a peak demand reduction of 157 MW.[137]

Hydro will continue to monitor Hydro-Québec's critical peak pricing offering to help determine if a similar program could have potential for customers in Newfoundland and Labrador.

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[134] Beneficial electrification (or strategic electrification) is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs for customers.
[135] Peak demand events can take place weekdays from December 1 to March 31 from 0600 hours to 0900 hours and from 1600 hours to 2000 hours. Maximum of 33 events with total maximum of up to 100 hours overall.
[136] There is no penalty for customers under this rate option, only the opportunity to achieve a bill credit for curtailed usage during peak demand events.
[137] "Dynamic pricing results," Hydro-Québec, <https://www.hydroquebec.com/residential/customer-space/rates/dynamic-pricing-results.html>

Additionally, Newfoundland Power has committed to file a Load Research Study and a Retail Rate Design Review in 2022. Hydro will support Newfoundland Power in completing these studies, as required.

Non-Firm Rates

On September 15, 2022, Hydro filed an application for approval of a rate for non-firm service in Labrador and to update the non-firm energy rate that applies to Industrial customers on the Island Interconnected System.[138] It is consistent with generally accepted utility practice in Canada that non-firm rates consider the marginal/incremental cost of supplying the additional energy use. The non-firm rate for the Labrador Interconnected System is proposed to enable Hydro to supply new customers while dealing with transmission capacity constraints on the Labrador Interconnected System.

With the interconnection to the North American Grid, the marginal energy costs for both systems should now consider the market value of exports. However, the non-firm energy rate for the Island Interconnected System currently reflects system fuel costs in determining the price to charge customers for additional usage. Therefore, Hydro's application also proposed to update the non-firm energy rate for the Island Interconnected System and enable the market value of exports to be considered in determining the non-firm energy price.

Electric Vehicles

In 2022, Hydro engaged Dunsky Energy + Climate Advisors[139] ("Dunsky") to provide a system planning study to evaluate the forecast impact of EVs on Hydro's load forecast and resource adequacy.[140,141] Based on Dunsky's analysis, the potential electrical system impact from EVs could be substantial. In the next ten years, Dunsky estimates that Newfoundland and Labrador will have approximately 38,000 EVs[142] requiring more than 260 GWh of energy and contributing more than 80 MW to system peak if left unmanaged. By

[138] "Application for a Non-Firm Rate for Labrador," Newfoundland and Labrador Hydro, September 15, 2022.
[139] Formerly Dunsky Energy Consulting (6893449 Canada Inc.).
[140] The intent of this study was to forecast EV system impacts to inform Hydro's system and resource planning. This scope is distinct from the "Conservation Potential Study – Final Report," Dunsky Energy Consulting (6893449 Canada Inc.), August 12, 2019, which was filed as Schedule C in the "2021 Electrification, Conservation and Demand Management Application," Newfoundland Power Inc., December 16 2020, vol. 2 and as Schedule C in the "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, July 8, 2021, sch. 3.
[141] The "EV Adoption and Impacts Study – Final Results," Dunsky Energy + Climate, August 23, 2022 is included as Attachment 2 of the "Long-Term Resource Plan" included as part of the 2022 Update.
[142] 36,000 light-duty EVs and 2,000 medium- or heavy-duty EVs.

2040, Dunsky estimates that there will be more than 160,000 EVs in Newfoundland and Labrador,[143] resulting in more than 1,300 GWh of energy sales and contributing more than 400 MW to system peak if left unmanaged.[144]

The contribution to peak demand resulting from EV adoption will need to be managed carefully. Dunsky's analysis considered the use of 'smart' EV chargers to allow utility-controlled smart EV charging behaviours that shift charging to off-peak hours. Managed EV charging has the potential to lower system peak by 16 MW in 2032 and 100 MW in 2040.

EV charging demand response programming was considered in the filing of applications by Hydro and Newfoundland Power for the joint Electrification, Conservation and Demand Management proceeding.

Electrification, Conservation and Demand Management Application

Newfoundland Power filed its "2021 Electrification, Conservation and Demand Management Application" with the Board on December 16, 2020.[145] On June 16, 2021, Hydro filed its "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025."[146]

Both Hydro and Newfoundland Power's (collectively, the "Utilities") applications reflect the Utilities' continued collaboration in developing and delivering customer programs as outlined in the "Electrification, Conservation and Demand Management Plan: 2021–2025" ("2021 Plan").[147]

The 2021 Plan includes programming to encourage customer electrification that will provide rate-mitigating benefits over the long term, as well as the continuation of existing energy efficiency programming. In addition, the 2021 Plan includes load management initiatives, such as the Residential EV & Charging Infrastructure Program that will incent the purchase and installation of smart Level 2 EV chargers capable of demand response, combined with a Demand Response Pilot Program. This program is critical to encourage EV charging behaviour during off-peak hours, as contemplated in the 2021 Plan and

[143] 147,000 light-duty EVs and 13,000 medium- and heavy-duty EVs.
[144] Light-, medium-, and heavy-duty EVs combined.
[145] "2021 Electrification, Conservation and Demand Management Application, Newfoundland Power Inc., December 16, 2020.
[146] "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021).
[147] Ibid., sch. 3.

the Dunsky EV Adoption and Impacts Study, as electrification that occurs during system peak has the potential to increase system costs.

Heat Pumps

Previous studies performed by Synapse Energy Economics, Inc.[148] and Dunsky[149] commented on the material increase in heat pump usage on the Island Interconnected System and the potential for additional conversions to the use of heat pumps. To provide an increased understanding of system load impacts from heat pump usage, Newfoundland Power hired Econoler to design and conduct a study to quantify such impacts. The objective of the study was to understand the impact that increasingly high penetration of heat pumps can have on the Island Interconnected System demand peak load requirements and to understand how heat pumps operate by analyzing their power demand and energy consumption.

In October 2021, Newfoundland Power released the results and findings of the study after 16 months of metering data was analyzed (January 2020 to April 2021).[150] Energy savings were estimated at approximately 3,150 kWh per household (13.3% of annual electricity consumption) and peak demand savings were estimated at 0.89 kW per household for weather conditions similar to those experienced over the study period. However, due to the relatively mild winter weather conditions experienced in 2020–2021, it was determined additional data would be required to assess the performance and thus impacts on the system during colder winter weather conditions.

It was decided to continue metering the customers during winter 2021–2022 and perform additional analysis if colder weather conditions were experienced. Unfortunately, the Island did not experience the colder weather necessary to conduct additional analysis. Newfoundland Power plans to continue to collect heat pump data during the 2023 winter season to further analyze the impact heat pumps are having on peak demand. In the event that the 2023 winter season does not yield colder weather conditions than

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[148] "Phase 2 Report on Muskrat Falls Project Rate Mitigation," Synapse Energy Economics, Inc., rev. September 25, 2019 (originally filed September 3, 2019, <http://www.pub.nf.ca/applications/2018ratemitigation/report/Synapse%20Energy%20Economics%20Inc.%20-%20Phase%20Two%20Report%20-%20September%203,%202019.pdf>
[149] "Conservation Potential Study – Final Report," Dunsky Energy Consulting (6893449 Canada Inc.), August 12, 2019.
[150] The "Heat Pump Load Study – Annual Results – Final Report," Econoliner, October 26, 2021 was filed as Appendix D to the "2021 Conservation and Demand Management Report," Newfoundland Power Inc., April 1, 2022, <http://www.pub.nf.ca/indexreports/conservation/From%20NP%20-%202021%20Conservation%20and%20Demand%20Management%20Report%20-%202022-04-01.PDF>

those experienced in 2020, 2021, and 2022, Newfoundland Power will consult with Hydro on other possible means of assessing the impact of heat pumps on peak demand.

7.1.2 Market Purchases

To date, Hydro has not secured any capacity support from external markets for a duration longer than one month and does not have a basis to assume that such solutions would be available to meet long-term planning requirements. On this basis, market purchases were not included in the analysis. Hydro will continue to work with neighbouring utilities to explore the availability of firm supply solutions that could support reliability in the event of a LIL bipole outage.

7.1.3 Bay d'Espoir Unit 8

Bay d'Espoir Unit 8 is a proposed 154 MW unit that would be located in Powerhouse 2 next to existing Unit 7. The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned. This project would provide capacity to the system. As this project would share the existing annual water supply from the existing watershed, there is no direct increased energy production associated with this project.

Bay d'Espoir Unit 8 would interconnect to the Island Interconnected System via the construction of a 1.5 kilometre 230 kV line from the Unit 8 step-up transformer to Bay d'Espoir Terminal Station 2.

An AACE Class 3 capital cost estimate was developed by SNC Lavalin Inc. in 2017 and the cost has been escalated to 2022 dollars. The criteria, assumptions, and methodology that went into developing the estimate can be found in Attachment 6 to the "Long-Term Resource Plan" included as part of the 2022 Update.

In the 2019 Update, Hydro committed to executing a hydrology and feasibility study to assess the impact of Bay d'Espoir Unit 8 on the Bay d'Espoir reservoir system. The objective of the study was to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system. The scope of work included data review, hydrological analysis, power and energy model analysis, and the identification of any required environmental studies. The power and energy analysis concluded that the addition of Unit 8 to the Bay d'Espoir Hydroelectric Generating Facility does not impact the firm energy of the Bay d'Espoir system. However, one of the recommendations was to conduct a hydrology study to examine the impact of water surface drawdown on the adequacy of submergence of power intakes. The full hydrology study can be found in Attachment 7 to the "Long-Term Resource Plan" included as part of the 2022 Update.[151]

7.1.4 Thermal Generation and the 2035 Clean Electricity Standard

The proposed Clean Electricity Standard[152] has brought into question resource options that would traditionally have been recommended but now have an uncertain position as a future resource option (i.e., fossil fuel-burning combustion turbine). Hydro will continue to assess thermal generation as a resource options in relation to the proposed Clean Electricity Standard and investigate gas turbines with a renewable fuel source as a resource option in the 2023 Update.

In addition, existing assets, such as the Holyrood TGS, the Hardwoods Gas Turbine, and other thermal generation, may require replacement upon the implementation of this standard. Hydro's current proposal is to extend these assets to 2030; however, should the integration of new generation be delayed, these thermal assets may not be extended much beyond the current assumption of 2030, regardless of clean energy requirements.

7.2 Long-Term Resource Plan Results

The results of the reserve margin-based analysis across all four scenarios indicate that the requirement for additional resources is capacity driven and most sensitive to the LIL bipole forced outage rate assumptions. A summary of the incremental resource additions for these cases are included in Table 15.

[151] "Final Report for Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8," Hatch Ltd, December 11, 2020.
[152] "Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035," Environment and Climate Change Canada, March 15, 2022, <https://www.canada.ca/en/environment-climate-change/news/2022/03/canada-launches-consultations-on-a-clean-electricity-standard-to-achieve-a-net-zero-emissions-grid-by-2035.html>

Table 15: Island Interconnected System Long-Term Resource Plan[153]

	Island Base Growth		Island High Growth	
Year	**Labrador Base**	**Labrador High Growth**	**Labrador Base**	**Labrador High Growth**
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	154 MW BDE 8 + 330 MW	154 MW BDE 8 + 330 MW	154 MW BDE 8 + 430 MW	154 MW BDE 8 + 430 MW
2031	-	-	-	-
2032	-	-	-	-

Bay d’Espoir Unit 8 has consistently shown to be the least-cost option across a multitude of assumptions. Hydro remains committed to better understanding the roles that Customer Demand Management, rate structure, and alternative technologies such as wind and battery storage, can play in the Newfoundland and Labrador Interconnected System. The ability to use alternative resources to supply the Newfoundland and Labrador Interconnected System will depend on the timeframe in which decisions on investment are required. As indicated in Table 15, Hydro requires incremental resources as early as 2030 in all cases due to the retirement of the Holyrood TGS and the Hardwoods Gas Turbine at the end of 2030 and the need for backup generation to mitigate the loss of the LIL.[154]

As identified in the 2019 Update, Bay d’Espoir Unit 8 is currently the proposed option for adding additional firm generation capacity to the Island Interconnected System. Bay d’Espoir Unit 8 has other advantages—it can be used for base load generation, it is a renewable source of generation, and it is part of an existing

[153] Island Interconnected System capacity requirements are reported based on a P50 peak demand forecast. The capacity requirements based on a P90 peak demand forecast would require an additional 60 MW to the capacity requirement reported in each case.
[154] The Island Interconnected System capacity requirements are based on a P50 peak demand forecast. Hydro maintains that basing supply planning decisions on a P50 peak demand forecast, while continuing to assess and report to the Board on forecast exposure under the P90 peak demand forecast, balances system reliability and investment cost at this time. Further, by embedding load forecast uncertainty in the determination of planning reserve margin increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discreetly.

hydro system (i.e., a brownfield site, with minimal environmental impact compared to a greenfield site). A study completed by Hatch in 2020 confirmed that Bay d'Espoir Unit 8 is an appropriate option from a hydrological point of view. The capacity and operational flexibility provided by a hydro unit such as Bay d'Espoir Unit 8 could also be used to support intermittent renewable generation in the future, such as wind generation.

As described in Section 7.1.3, the addition of Bay d'Espoir Unit 8 would likely not add energy to the Island Interconnected System. If the high load growth scenario in Labrador materializes, additional energy would be required in support of the Newfoundland and Labrador Interconnected System, as identified in Section 6.0.

8.0 Discussion and Recommendations

The results of the reserve margin-based analysis and shortfall analysis indicate that additional capacity is required on the Island Interconnected System to meet Hydro's reliability criteria once the Holyrood TGS and the Hardwoods Gas Turbine are retired. By 2032, the reserve margin requirement for additional capacity is forecasted to be approximately 480 MW in the base Island growth case. The forecasted capacity requirement is expected to increase as peak load on the Island Interconnected System increases. Increased load on the Labrador Interconnected System did not have a material effect on reliability and, by extension, expansion requirements. This capacity requirement is significantly higher than the requirement identified in the 2018 Filing and the 2019 Update, driven by the increased forced outage rate assumptions for the LIL. Regardless, the Island Interconnected System dependency on the LIL is such that should the LIL be unavailable for up to six weeks in the winter of 2032, a generation shortfall of up to 508 MW in the severe case (90th percentile) and a shortfall of up to 428 MW in the average case (50th percentile), could occur. Due to the uncertainty of LIL reliability and the associated impact on overall system reliability, it is expected that the reserve margin could change significantly (higher or lower) once actual operational data for the LIL is available.

Regardless of the assumptions made for Island Interconnected System load growth, LIL capacity, and bipole forced outage rate, the Island Interconnected System will be significantly capacity constrained once the Holyrood TGS and the Hardwoods Gas Turbine are retired.

Resource Planning is not a precise process. It is a continuous process driven by an ever-changing energy landscape of customer requirements, weather uncertainties, grid reliability, and evolving provincial environmental priorities. The 2022 Update continues Hydro's efforts to be transparent in its decision-making relative to resource planning. A summary of the main concepts brought forward in the 2022 Update follows.

8.1 Resource Needs for the Island Interconnected System

In the 2018 Filing and 2019 Update, the Muskrat Falls Hydroelectric Generating Facility in combination with the LIL was expected to allow for the retirement of aging on-Island thermal resources—the Holyrood TGS and the Hardwoods Gas Turbine.

Delays in the commissioning of the LIL have delayed the retirement of both the Holyrood TGS and the Hardwoods Gas Turbine. Until such time as the LIL becomes fully integrated into the Newfoundland and Labrador Interconnected System and with a reliable track record established, Hydro does not advise retiring either thermal asset without replacement, as the Island could be subjected to unacceptable capacity shortfalls during winter peak demand periods.

The Holyrood TGS was designed as a base-load unit; as such, it is ill equipped to reliably handle the thermal-cycling and fast-starting requirements to serve as a backup for the LIL.

Once the LIL is fully integrated and the Holyrood TGS and the Hardwoods Gas Turbine have been retired and absent incremental generation additions, under severe conditions (90th percentile), the Island will still run the risk of major outages during winter peak demand periods if the LIL were to be unavailable for an extended period of time due to structural failure or some other major cause.

By 2032, load growth combined with anticipated the Holyrood TGS and the Hardwoods Gas Turbine retirements could drive the need for an incremental 480 MW of on-Island capacity to meet reliability planning criteria of loss of load of no more than one day in ten years (i.e., 0.1 LOLE).

8.2 Operational Needs for the Island Interconnected System

Operational (10- and 30-minute) reserves are driven by what constitutes the largest and second largest single contingency events on the Newfoundland and Labrador Interconnected System. The loss of individual units at the Holyrood TGS has historically been considered the largest contingency event. Once the LIL is fully integrated, the Holyrood TGS will be replaced by the individual units at the Muskrat Falls Hydroelectric Generating Facility as the largest contingency event.

By definition, once fully integrated, the loss of a LIL tower technically represents the largest single contingency to the Newfoundland and Labrador Interconnected System; however, given the robust (50-year) nature of the tower design, Hydro has elected not to treat the loss of the LIL as such.

8.3 Resource Needs for the Labrador Interconnected System

Labrador is experiencing unprecedented requests for incremental load additions. Load additions are still forecasted to be 1,300 MW after cost implications were defined and presented to potential customers. While requests for the load on the Labrador Interconnected System have been reduced, the issue has not been eliminated.

If the Labrador load materializes, it will result in a syphoning of the Muskrat Falls Hydroelectric Generating Facility to serve local load requirements, reducing the ability to serve the Island, which will in turn drive a need for additional incremental additions on the Island, well beyond the 480 MW of new incremental capacity previously mentioned.

8.4 Recommendations

1) To address the immediate need to backup the LIL on an interim basis, Hydro recommends extending operations of the Holyrood TGS and the Hardwoods Gas Turbine, potentially through 2030. Admittedly an imperfect solution; however, one that Hydro believes is necessary due to limited options available to backup the LIL due to reliability concerns.

2) To better position the Holyrood TGS in this backup role, Hydro recommends continued investment in capital improvements to the facility. Further, operational changes are being made to improve the reliability and responsiveness of the Holyrood TGS. During anticipated periods of high demand, the Holyrood TGS maybe placed online prematurely in anticipation of a potential need.

3) As the results of the Wind Integration Process and the *Network Additions Policy* implications become clearer, Hydro will continue to investigate resource alternatives to the Holyrood TGS and the Hardwoods Gas Turbine as a means of ensuring the reliability of the Island Interconnected System.

4) Previous analyses have repeatedly identified Bay d'Espoir Unit 8 as a preferred, least-cost, renewable resource expansion option at an existing site. Given the projected long-term needs for incremental on-Island generation, Hydro proposes beginning the regulatory process to seek approval to construct Bay d'Espoir Unit 8.

Hydro looks forward to participating in the regulatory process to further inform parties on the results of this 2022 Update and working with stakeholders and the Board to determine which scenarios should drive capital investment. Hydro will ensure system needs are well understood and all options have been carefully considered before recommending significant investments. Further optimization of results will be undertaken, as required, to support decision-making and as part of the regular planning exercise.

9.0 Action Plan

Continuing to evolve the Resource Planning Process to optimally balance customer needs for reliability with least cost, Hydro will continue to assess the need for additional generation, suitable generation expansion options, and the timing for new generation builds. Prior to the 2023 Update, Hydro commits to:

- Working with the Board and stakeholders to review Hydro's 2022 Update;
- Execute a stakeholder engagement process in 2023;
- Begin the regulatory process to seek approval to construct Bay d'Espoir Unit 8**;**
- Conduct a hydraulic study to examine the impact of water surface drawdown on the adequacy of submergence of power intakes;
- Further study to examine the impact that lower reservoir levels in advance of winter may have on generation with the addition of Bay d'Espoir Unit 8;
- Further study to examine the impact that a prolonged loss of the LIL (i.e., six weeks) has on reservoir levels in the winter and during shoulder seasons;
- Integrate outcomes of the Wind Integration Process, the *Network Additions Policy*, etc., to better inform subsequent filings;
- Study fuel availability in the event of a six-week LIL outage;
- Investigate expansion using gas turbines with renewable fuel source as a resource option;

- Assess pumped storage for new and existing facilities as a resource option;
- Assess existing hydro facilities for efficiency improvements; and
- Closely monitor the ongoing viability of extending the service life of the Holyrood TGS and the Hardwoods Gas Turbine.

Volume III, Attachment 1

Forced Outage Rate Methodology

newfoundland labrador hydro

Forced Outage Rate Methodology

Executive Summary

The forced outage rate methodology applied to the Reliability and Resource Adequacy Study varied by asset class, ownership, and condition. Forced Outage Rates ("FOR") were determined based on historical data where available or the most recent industry average. The historical data is based on a weighted average of Derated Adjusted Forced Outage Rate ("DAFOR") for hydroelectric units and the thermal generating units at Holyrood Thermal Generating Station ("Holyrood TGS"); Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") for gas turbine units; and Equivalent Forced Outage Rate Demand ("EFORd") for diesel units. For units not owned by Newfoundland and Labrador Hydro ("Hydro"), Canadian Electricity Association ("CEA") or North American Electric Reliability Corporation ("NERC") industry standards were used. FOR assumptions will be re-evaluated on an annual basis to incorporate the most recent data available. Table 1 provides a summary of values and measures used for existing generating assets. Table 2 provides a summary of values and measures used for expansion resource options.

Table 1: Forced Outage Rates for Existing Generating Assets

Unit Type	Measure	Near-Term Analysis Value (%)[1]	Resource Planning Analysis Value (%)[2]
Hydro-Owned			
Hydraulic[3]	DAFOR	1.69	2.32
Thermal	DAFOR	20	20
Gas Turbines			
Happy Valley	DAUFOP	6.65	7.60
Hardwoods and Stephenville	DAUFOP	30	30
Holyrood	DAUFOP	4.9	4.9
Diesel	EFORd	7.92	7.92
Power Purchases			
Corner Brook Pulp and Paper Co-Generation	DAFOR	20.88	N/A
Rattle Brook	DAFOR	2.23	2.23
Wind	N/A	N/A	N/A
Newfoundland Power Generation			
Hydraulic	DAFOR	2.23	2.23
Thermal	DAUFOP	5.33	5.33
Deer Lake Power			
Capacity Assistance	N/A	N/A	N/A
Hydraulic	DAFOR	2.23	2.23

Table 2: Forced Outage Rates for Expansion Resource Options

Unit Type	Measure	Resource Planning Analysis Value (%)
Battery	FOR	0.5
Hydroelectric	DAFOR	2.32
Gas Turbines and Combined Cycle Combustion Turbines	DAUFOP	11.3
Wind	FOR	N/A
Solar	FOR	0.5

[1] These values are used in Hydro's Near-term Reliability Assessments, which focus on system reliability in years 1 through 5.
[2] These values are used in Hydro's Near-term Reliability Assessments, which focus on system reliability in years beyond year 5.
[3] Includes units at Nalcor Energy Exploits Facilities.

Contents

1.0 Hydroelectric Units

For Hydro-owned hydroelectric units (Bay d'Espoir Hydroelectric Generating Facility, Cat Arm Hydroelectric Generating Station, Hinds Lake Hydroelectric Generating Station, Granite Canal Hydroelectric Generating Station, Upper Salmon Hydroelectric Generating Station, and Paradise River Hydroelectric Generating Station) a 3-year capacity-weighted average DAFOR was applied to these units for the near-term analysis, while a 10-year capacity-weighted average DAFOR was applied for use in the resource planning model. The DAFOR value was based on historical data which is reflective of Hydro's maintenance program over the long term. The long-term DAFOR was also applied to the Muskrat Falls Hydroelectric Generating Station ("MFGS") and the Exploits Generation Hydroelectric Plant units as it is assumed they will be maintained to the same standards. Once historical operational data from MFGS is available, the DAFOR will be re-evaluated.

For hydroelectric units not owned by Hydro (Rattle Brook, Newfoundland Power Hydro, and Deer Lake) the CEA G-ERIS report, which collects outage statistics from utilities across Canada, was used to determine the DAFOR.[4] The DAFOR is based on a five-year average. It was applied across all units in both the near- and long-term modelling and analysis.

2.0 Holyrood Thermal Generating Station

Historically, forced outage rates for the three units at the Holyrood TGS have been reported using the Derated Adjusted Forced Outage Rate (DAFOR) metric, which is predominately used for units that operate in a continuous (base-load) capacity. When considering stand-by or peaking operations of units at the Holyrood TGS, DAFOR is no longer the most appropriate measure of Forced Outage Rate. Common stand-by metrics include Derated Adjusted Utilization Forced Outage Probability (DAUFOP), which is currently used for Hydro's Gas Turbine fleet.

When considering stand-by or peaking operations of units at the Holyrood TGS, DAUFOP is a more appropriate measure given the frequency of deratings historically experienced by these units. The operational data, which is used as input data to produce the DAFOR measure, can also be used to

[4] "2020 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, table 6.1.2.

establish a historical record of the performance of these assets when considering operations in a stand-by or peaking capacity.

As noted in Volume III, Attachment 3 "Reliability Analysis of Holyrood Thermal Generating Station For Backup or Stand-by Operation," all operational data for the period of January 1, 1993[5] to May 1, 2022 for the Holyrood TGS were collected and two different methods of analysis were used to assess appropriate forced outage rates and a third analysis was completing to assess starting reliability of the units at the Holyrood TGS.

From this analysis, when considering future operations of the Holyrood TGS as a backup generating facility, it was recommended to use a DAUFOP value of approximately 20%. Additionally, as projected operation becomes better understood, appropriate sensitivity numbers should be selected to ensure a wide range of potential performance outcomes are considered. Refer to Volume III, Attachment 3 for the full analysis.

3.0 Gas Turbines

As the gas turbines in the existing fleet vary in age and condition, each was considered on an individual basis. For the Happy Valley Gas Turbine, a 3-year capacity-weighted average was applied to the unit for the near-term analysis, while a 10-year capacity-weighted average was applied for use in the resource planning model. The DAUFOP values were based on historical data founded upon the unit's past reliable performance. For the Holyrood Gas Turbine the DAUFOP was calculated based on a scenario approach rather than historical data. For Hardwoods and Stephenville Gas Turbines, a fixed DAUFOP consistent with values considered in Hydro's previous near-term reliability reports was used for the near-term analysis.[6]

4.0 Other

4.1 Corner Brook Pulp and Paper Co-Generation

A five-year average DAFOR is applied to both near- and long-term modelling and analysis. This value is based on the most recent CEA G-ERIS report for thermal-biomass units.[7]

[5] Accurate operational data for Holyrood Thermal Generating Station is not available for the period prior to January 1, 1993.
[6] "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, May 16, 2022.
[7] "2020 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, table 6.2.18.

4.2 St. Lawrence and Fermeuse Wind Farms

The forced outage rate is included in the probability distribution for both near- and long-term modelling and analysis.

4.3 Diesels

The EFORd from the most recent NERC Generating Availability Data System ("GADS") Report is applied to all diesel units for the near- and long-term modelling and analysis.[8,9] The EFORd is a measure used by NERC which is comparable to DAUFOP.[10]

4.4 Newfoundland Power Thermal

A 5-year average DAUFOP obtained from the most recent CEA G-ERIS report for combustion turbine units is applied for all gas turbine units in both near- and long-term modelling and analysis.[11]

5.0 Long-Term Resource Planning Study: Expansion Resource Options

5.1 Batteries

A forced outage rate of 0.5% was used as per consultant recommendation.[12]

5.2 Gas Turbines and Combined Cycle Combustion Turbines

Both expansion options utilized a 5-year average DAUFOP based on the CEA G-ERIS report for combustion turbines that are between 0-10 years old.[13]

5.3 Hydroelectric Generation

Assumed DAFOR is consistent with Hydro-owned hydroelectric units used in the long term.

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[8] "Generating Unit Statistical Brochure 4 (2016-2020) - All Units Reporting," North American Electric Reliability Corporation, August 9, 2021.< https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx>
[9] As the Canadian Electricity Association does not track diesel forced outage rate, the NERC-GADS Report was used.
[10] IEEE Std 762-2006 "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity," IEEE Power Engineering Society, March 15, 2007.
[11] "2020 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, table 6.3.2.
[12] Refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018), vol. III, att. 7.
[13] "2020 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, table 6.3.2.

5.4 Solar Generation

A forced outage rate of 0.5% was used as per consultant recommendation.[14]

5.5 Wind Generation

The forced outage rate for the wind generation option was included in the probability distribution.

[14] Refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018), vol. III, att. 6.

Volume III, Attachment 2

EV Adoption and Impacts Study – Final Results

newfoundland labrador hydro

EV Adoption and Impacts Study

Final Results

dunsky Energy + Climate

August 23, 2022


dunsky
Energy + Climate
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Design Strategies
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Table of Contents

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1. Introduction

1.1 Context
1.2 Approach

1. Introduction

Context: Study Scope

Dunsky Energy + Climate Advisors (Dunsky) was engaged by Newfoundland and Labrador Hydro (NLH) to assess the potential system load impacts associated with electric vehicle (EV) adoption in Newfoundland and Labrador

Scope of the study:

- Forecast EV uptake across the light-, medium-, and heavy-duty vehicle segments within the province
- Develop estimates of likely EV adoption within various geographies of the province; 2 zones (Island + Labrador)
- Assess the impacts of the forecasted EV uptake on annual energy consumption (GWh) and hourly demand (MW)

This deliverable highlights results from the study, with a focus on the forecasted EV adoption in the province under various policy, market and technology conditions. Detailed results were provided to NLH in the form of an Excel-based results dashboard.

1. Introduction

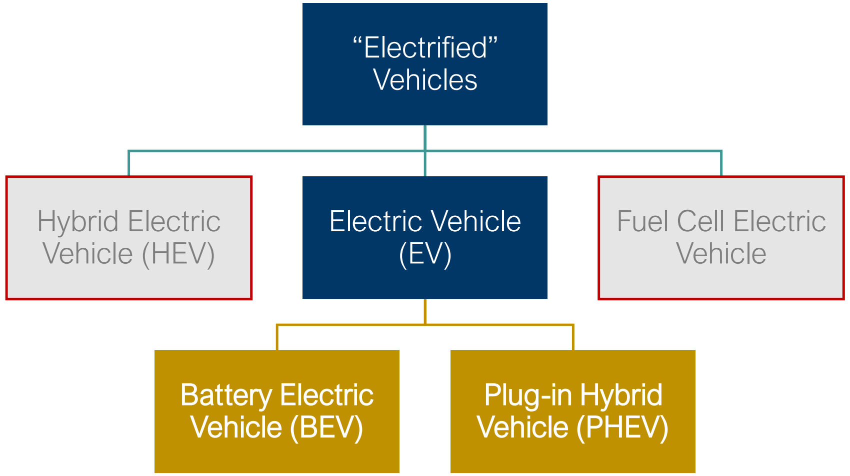
Context: Defining Electric Vehicles

The study considers plug-in EVs, specifically:

- **Battery Electric Vehicles (BEVs):** “pure” electric vehicles that have only an electric powertrain and that plug in to charge (e.g., Tesla Model 3, Chevy Bolt, Nissan Leaf)
- **Plug-in Hybrid Electric Vehicles (PHEVs):** hybrid vehicles that can plug in to charge and operate in electric mode for short distances (e.g. 30 to 80 km), but that also include a combustion powertrain for longer trips. (e.g., Chevy Volt, Toyota Prius Prime)

The following are excluded from the analysis:

- **Hybrid Electric Vehicles (HEVs)** that do not plug in to charge and are considered internal combustion engine (ICE) vehicles.
- **Fuel Cell Electric Vehicles (FCEVs)** (i.e., hydrogen vehicles): market assumed to be small within the timeframe of the study for all vehicle segments



Chevrolet Bolt, a BEV with 417 km of range.

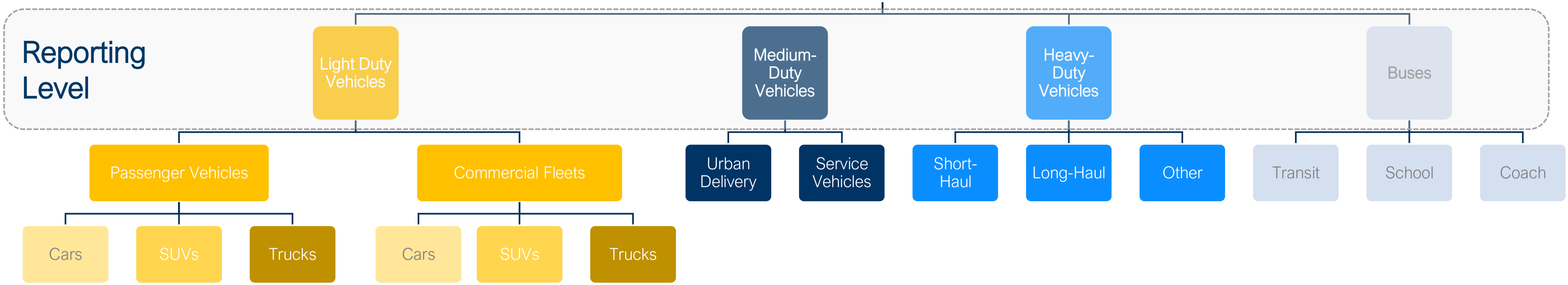
Toyota Prius Prime, a PHEV with 40 km of EV range

1. Introduction

Context: Defining Vehicle Segments

Multiple vehicle classification systems exist, however, for the purpose of this study, we break down the on-road vehicle market into several key segments that share common characteristics

- Results are broken down into for light-, medium-, heavy- duty vehicles and buses
- More granular vehicle sub-segments were used in the modeling to capture vehicle segments with distinct factors that may impact EV adoption (e.g. limited availability of EV model, unique driving patterns or technical needs, etc.)



* The study does not model commercial light-duty vehicle segment distinctly. The analysis of light-duty vehicles focuses on the personal vehicle market (the majority light-duty vehicle market) and assumes that the commercial vehicle market follows a similar trajectory,

Context: Vehicle Market

Approximately 383,000 vehicles on the road in Newfoundland and Labrador

- 81% of vehicles are passenger/personal light-duty vehicles (LDVs)
- LDVs make up 90% of vehicles on the road, with the remaining 10% being medium-and heavy-duty vehicles (MHDVs)

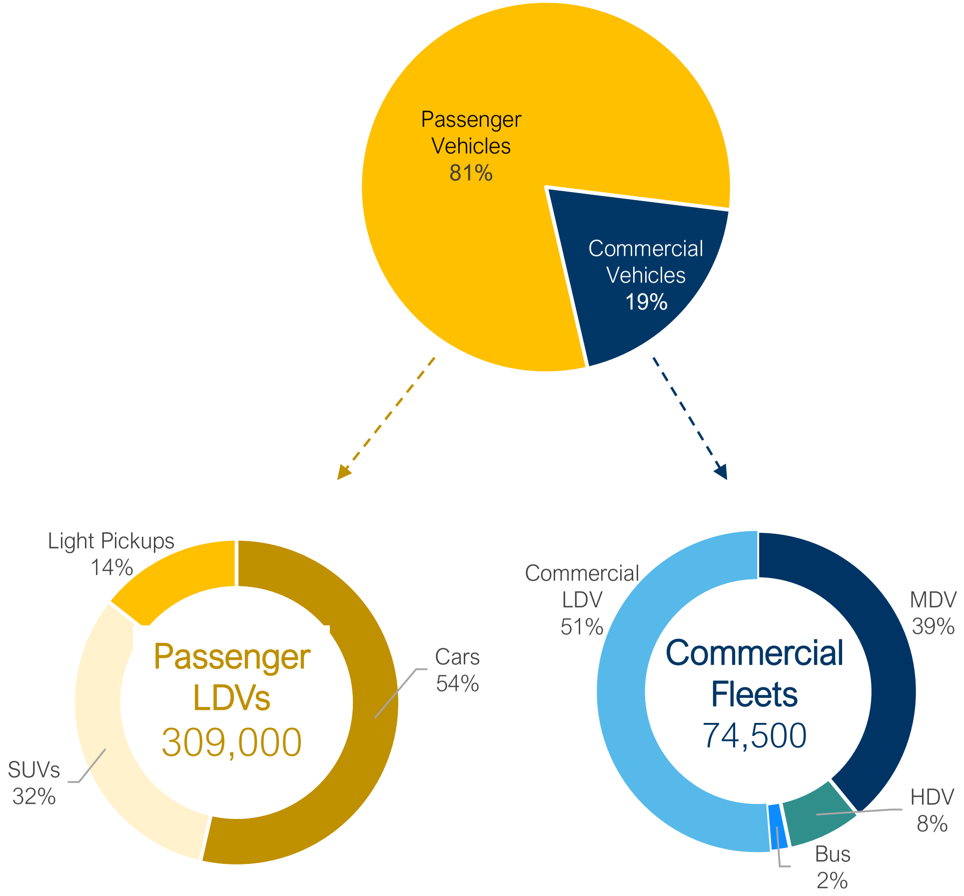
25,500 new LDVs registered annually

- Majority (89%) of LDVs predominantly passenger/personal use, with the remaining being commercial/institutional fleets
- SUVs and Trucks make up 55% of new vehicle sales, in-line with historical trends of increasing customer interest in larger vehicles

2,500 new MHDVs estimated registered annually

- Medium-Duty Vehicles make up nearly 83% of vehicles in the MHDV segment

Total Registered Vehicles (2020)



% of Total Vehicles 2020

1. Introduction

Context: Electric Vehicle Market

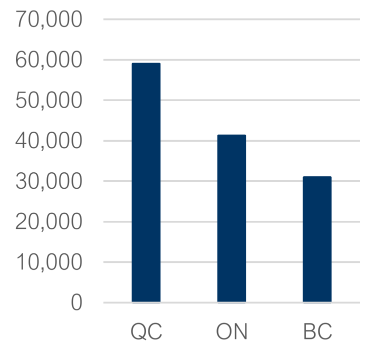
EV Adoption in Newfoundland and Labrador (NL) significantly lags behind other Canadian provinces

- Approximately 400 EVs registered (2020) in the province
- EVs represent 0.3% of new vehicle sales (2020)

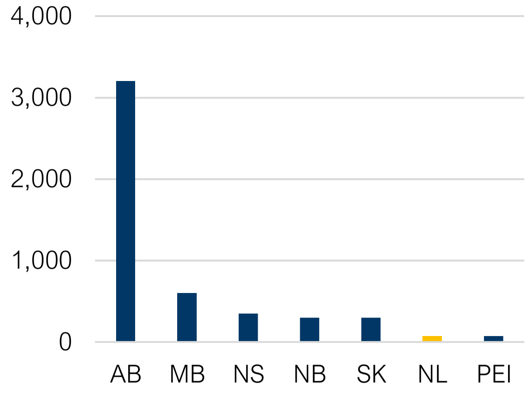
In NL, EV adoption increased starting in 2018

- A significant increase in uptake observed in 2018 (federal ZEV incentives began in 2019)
- Relatively consistent share of BEVs over the last 3 years (~50% BEV/PHEV split)
- Limited uptake of EVs within the Medium and Heavy-Duty Vehicle (MHDV) segment

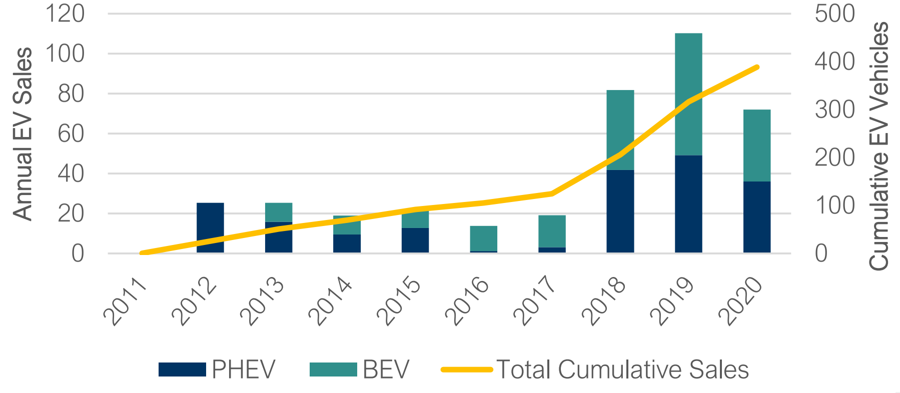
Top 3 Provinces 2019 (131,300 EVs)



Remaining Provinces - 2019 (4,900 EVs)



Newfoundland and Labrador EV Sales (2011 – 2020)

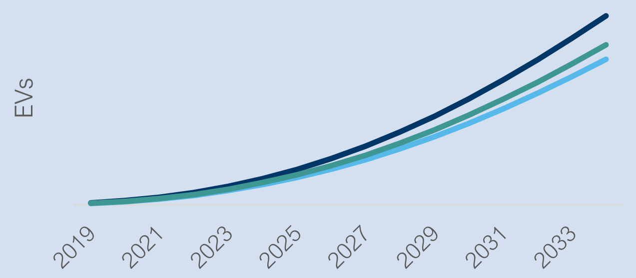


1. Introduction

Approach

The study follows the following three steps to assess the potential impacts of EVs within Newfoundland and Labrador. Key aspects of the study approach are highlighted throughout the report.

Forecast EV Adoption

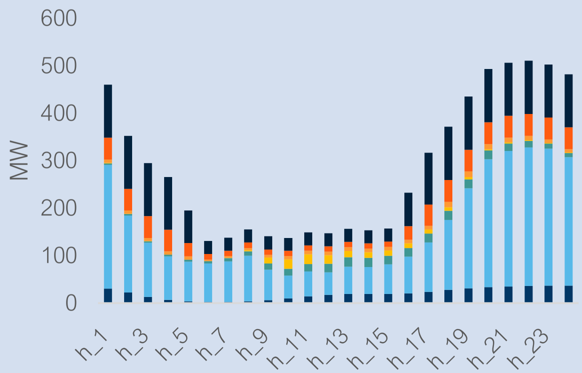


Using Dunsky's Electric Vehicle Adoption (EVA) model, forecast EV uptake within the province under various scenarios reflecting different policy, program and technology conditions.

Develop Regional Projections

Estimate EV adoption across 2 provincial zones based on high-impact factors likely to influence regional variation in EV adoption.

Assess Load Impacts



Assess the energy (GWh) and peak demand (MW) impacts associated with EV charging loads

1. Introduction

Approach: EVA Model

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The study leverages Dunsky's Electric Vehicle Adoption (EVA) Model to forecast the uptake of EVs.

EVA
powered by dunsky

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, trucks, buses)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/BEV over ICE vehicles
- Total Cost of Ownership (TCO) (personal) or Internal Rate of Return (IRR) (commercial) based on operational and fuel costs

CONSTRAINTS

Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between vehicles types (PHEV vs. BEV)

Approach: Forecasted EV Adoption Overview

The EVA model was applied to forecast EV adoption using the following approach:

1. **Market Characterization:** Divide the market into vehicle segments (as depicted earlier), develop representative characteristics for each segment and collect data on annual vehicle sales, fleet size and other key market inputs.

2. **Model Calibration:** Using historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment to benchmark the model to historical adoption and calibrate key model parameters to local market conditions.

3. **Scenario Analysis:** Forecast service territory-wide EV adoption under scenarios reflecting different program/policy interventions (e.g. infrastructure deployment, incentives) as well as market and technology conditions (e.g. battery costs, energy prices).

Approach: Passenger Vehicles versus Commercial Fleets

Consideration and treatment of key barriers in the model for personal vehicles and commercial fleets reflects key differences in decision-making between the segments.

Barrier	Personal LDV	Commercial LDV	Commercial MHDV
Technical	Base vehicle assumed to be **gasoline ICEV**		Base vehicle assumed to be **diesel ICEV**
Economic	**Upfront cost and Total Cost of Ownership (TCO)**	Based **on Internal Rate of Return (IRR)** of the vehicle's upfront and operational costs over its lifetime.	
Constraints	• Range Anxiety • Charging Time • Public Charging Coverage • **Public Charging Availability** • **Home Charging Access**	• Range Requirement • Charging Time Requirement • Public Charging Coverage	• Range Requirement • Charging Time Requirement
Market	**Competition** between PHEV and BEVs		**No competition** between PHEVs and BEVs (i.e. all assumed to be BEVs)

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2. Provincial Summary

2.1 Load Impact Summary
2.2 Load Management

2. Provincial Summary

Load Impact Summary: High Growth Scenario (2040)

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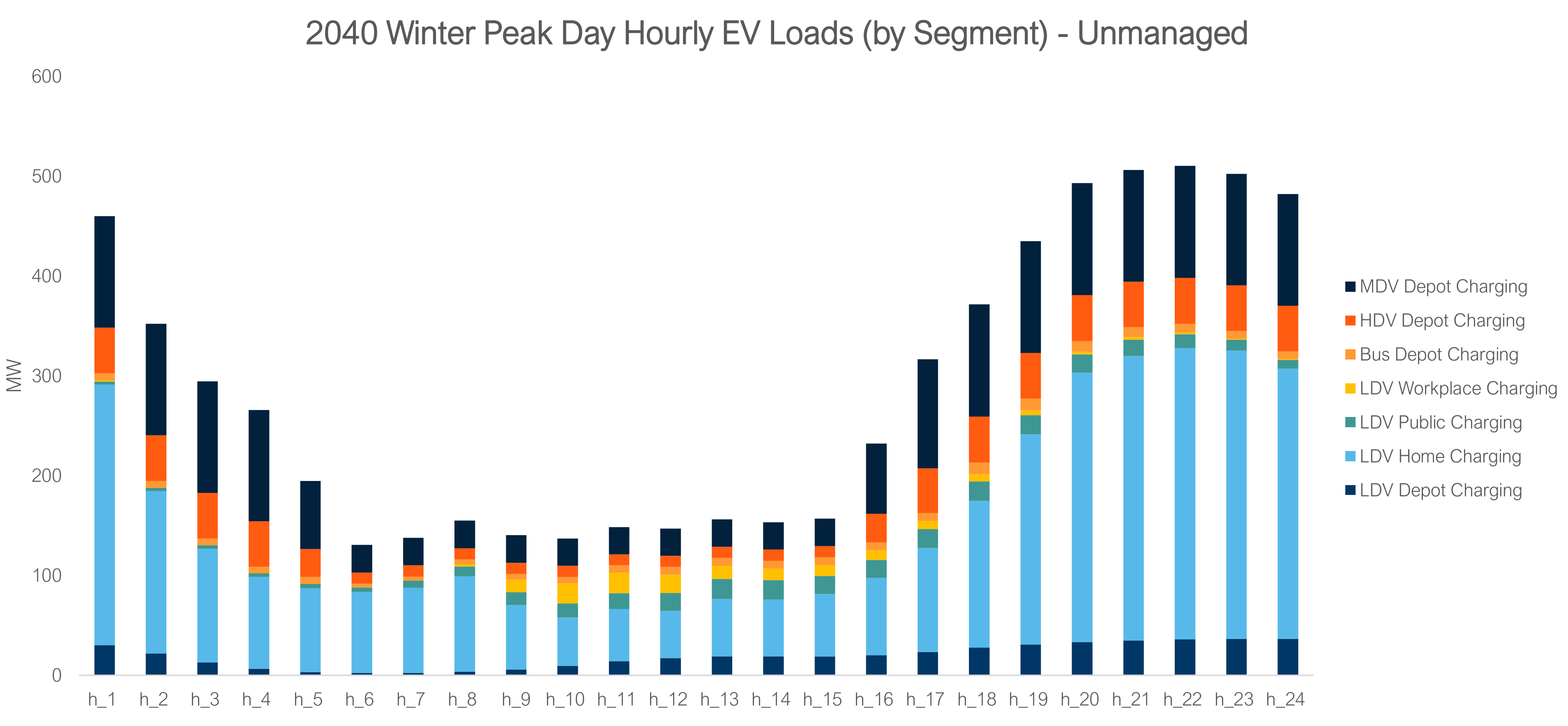
- **In 2040, if unmanaged, LDV home charging will be the primary driver of demand among EVs, contributing to a total EV load of over 500 MW at 10pm**

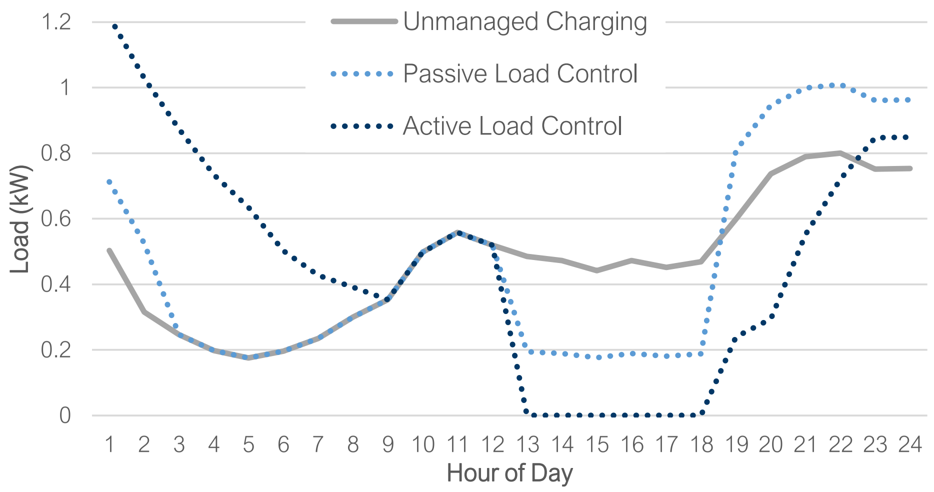


Key Consideration: Load Management

The inherent flexibility of EV charging loads means that they can be controlled, managed and potentially leveraged as Distributed Energy Resources (DERs) to reduce the peak demand impacts and bring additional system value

- Personal vehicles are usually connected to a charger much longer than required to obtain a full charge, therefore charging loads can be reduced or delayed with minimal disruption to drivers.
- Several EV load management strategies can be employed to shift charging loads from peak to off-peak hours, however generally they can be grouped into two categories

Illustration of the Impacts of Load Management



Strategies	Description	Examples	Impact
Passive Load Management	Rely on customer behavior and response to information, price signals or incentive from the utility	• Whole-home or EV-specific Time-of-Use (TOU) rates • Compensation for off-peak charging (e.g., “Smart Reward” program) • Utility guidance to EV drivers on setting a charge schedule	• Less certainty about customer response • Typically lower implementation costs • Risk of creating secondary peak with snapback
Active Load Management	Utility can manage charging loads through direct control, preset control strategies or other mechanisms	• Control via smart EVSE (e.g. Flo X5, ChargePoint Home, JuiceBox Pro) • Control via EV telematics (e.g. PG&E BMW Charge Forward pilot)	• Greater control over peak impacts, with ability to avoid snapback • Can help accommodate variable renewables

2. Provincial Summary

Key Consideration: Load Management

Managed Charging programs offer an opportunity to alleviate peak impacts of EV's

- Typically only personal LDVs are considered for these programs due to lower drive cycles and longer overnight charging periods

Managed charging programs could be considered, including **education and awareness campaigns**, **charging control using EV telematics**, or **Smart Charger programs**

- Each program type varies with respect to level of effort, peak reduction impacts, and technology certainty

Managed Charging Program	Utility Cost/Level of Effort	Peak Load Reduction Impacts	Technology certainty
Education and Awareness Campaign	**Low**	**Low**	**High**
Charging Control Using EV Telematics	**Mid**	**High**	**Low**
Charging Control Using Smart Chargers	**High**	**High**	**High**

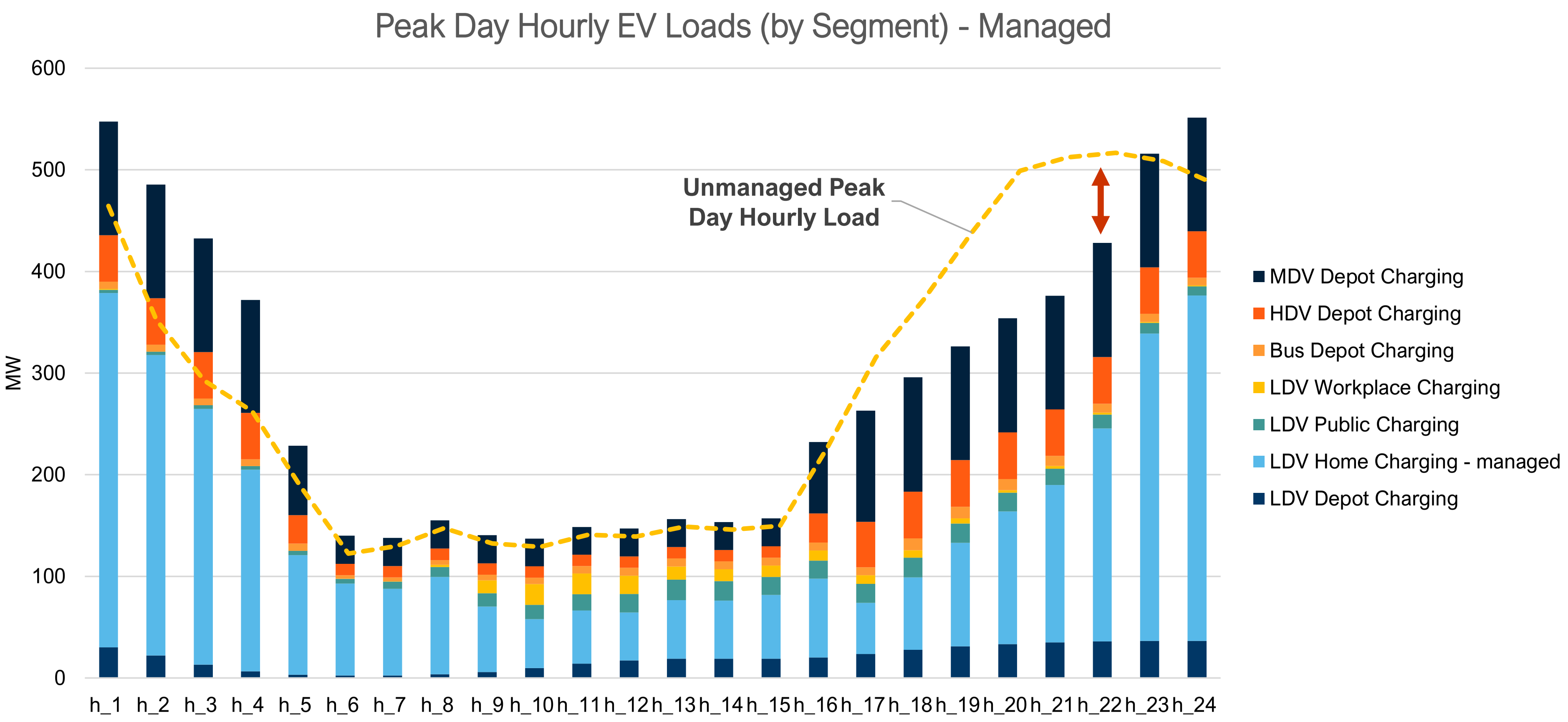
Education and awareness: EV drivers can be encouraged to purchase smart chargers, programming them to charge overnight and reduce evening peaks. There is uncertainty around customer response/degree of peak shifting. In addition, shifts will be 'blocky', as all EV owners will be given the same targeted time period to charging. This risks creating a secondary peak.

Telematics: Charging can be controlled through direct communication with vehicle telematics using a Demand Response Management System (DRMS). To-date, the communications protocols are not standardized between manufacturers; impact will depend on technological standardization moving forward.

Smart Chargers: Utilities can incentivize smart charger purchases with the expectation that participants will be willing to participate in a managed charging program in the future. Smart chargers are typically controlled through a utility DRMS.

Load Impact Summary: High Growth Scenario (2040)

- **Managed home charging can significantly reduce evening EV load by shifting to overnight**



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3. Light Duty Vehicles

3.1 Provincial Scenarios
3.2 Regional Impacts
3.3 Provincial Results

LDV Scenarios

	Scenario 1: Low Growth	Scenario 2: Moderate Growth	Scenario 3: High Growth
Vehicle Incentives	Current federal and provincial incentives *(Ramped down and phased-out by 2025)*	Extended federal and provincial incentive *(Ramped down and phased-out by 2030)*	Extended federal & provincial incentive *(Ramped down and phased-out by 2035)*
Public DCFC Public/Workplace Level 2	Limited expansion of public charging network	Expansion in-line with historical trends	Significant investments in public charging deployment
Home Charging Access in MURBs	0.2% (125 stalls) retrofitted per year	• 0.5% stalls retrofitted per year • 5% (in 2021) to 25% (2035) of new construction EV-Ready	• 1% stalls retrofitted per year • EV-Ready building codes starting 2026 (i.e. 100% of new construction)

Note: The Federal government aims to achieve 100% Zero Emission Vehicle (ZEV) market share by 2035.
While uncertainties around the specific mechanisms and pathways to achieving this target exist, it does signal continued investments and supporting programs/policies to support EV uptake.

3. Light Duty Vehicles

Sensitivities: Light-Duty Vehicles

	Low Sensitivity Scenario (Most Conservative)	Base Case	High Sensitivity Scenario (Most Aggressive)
Battery Costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV Model Availability	Limited availability	Moderate availability	High availability
Electricity Cost Escalation	1% higher than historical	Historical levels *(≈ 3% per year)*	1% lower than historical
Fuel Price Escalation	Historical escalation	Historical escalation (≈ 2% per year) + $170/ton carbon tax by 2030	Historical escalation (≈ 2% per year) + $170/ton carbon tax by 2030
Vehicle Sales	Declining vehicle sales	No growth in vehicle sales	Increase in vehicle sales at current pace

Regional Disaggregation

The province-wide adoption forecast is disaggregated into 2 regions to estimate the geographic distribution of EV adoption within the province, based on five high-impact factors most likely to influence regional variation in EV uptake

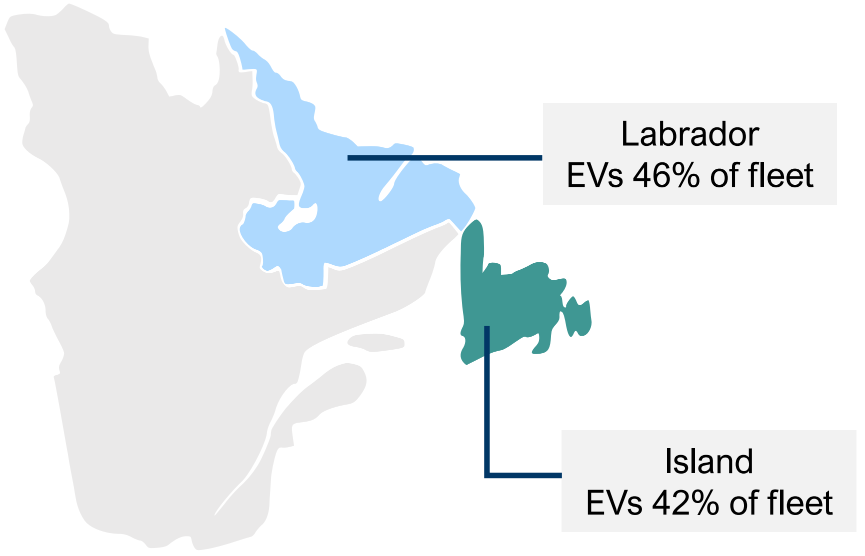
- Number of vehicles
- Historic EV sales
- Housing composition
- Income levels
- Driving distance

Regional variations in passenger EV uptake are a function of:

- The distribution of passenger vehicles across the province (higher populations = more cumulative EVs)
- Other regional differences in income levels, housing composition and typical driving distances across the province - among other factors – that will impact local penetration of EVs.
- While the vast majority of cumulative EVs will be found on the island (94%) due to population distributions, % of fleet will be slightly higher in Labrador given the lack of urban areas with additional barriers to home charging access.

The following results in the report are at the provincial level and more detailed regional outputs can be found in the Excel-based results dashboard

2040 High Scenario - LDVs



3. Light Duty Vehicles

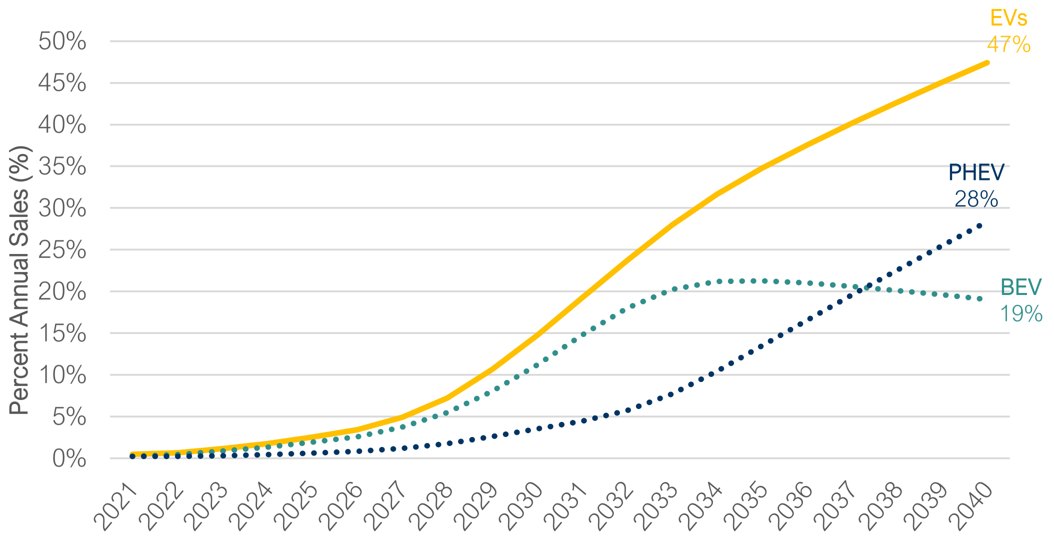
Low Growth Scenario

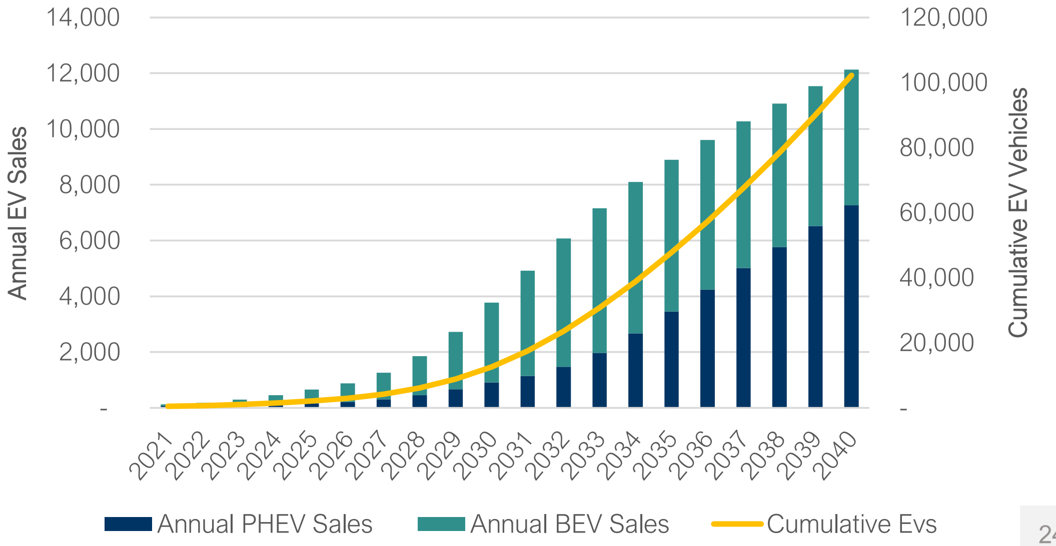
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2040)	Public / Workplace Level 2 (by 2040)	Home Charging Access in MURBs (by 2040)
Current federal incentives (phased-out by 2025)	65 Sites (65 Ports)	100 Sites (200 ports)	6%

Under the Low Scenario, Newfoundland and Labrador will experience very modest growth in EV uptake.

- By 2040, a total of **100,000 EVs** of the 307,000 LDVs are forecasted to be on the road
- EV adoption is expected to **fall significantly short of federal 2035 ZEV targets (100%),** reaching only 35% of new sales by 2035
- Despite the growth in overall EV uptake, the **market share shifts towards PHEVs by 2037** as public infrastructure deployment in this scenario is insufficient to meet needs of BEV drivers.





3. Light Duty Vehicles

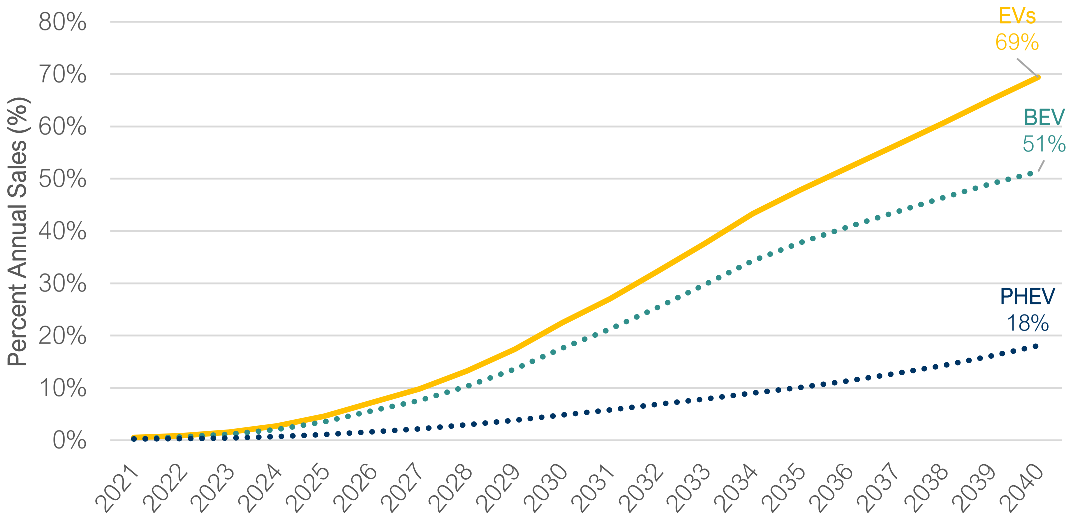
Medium Growth Scenario

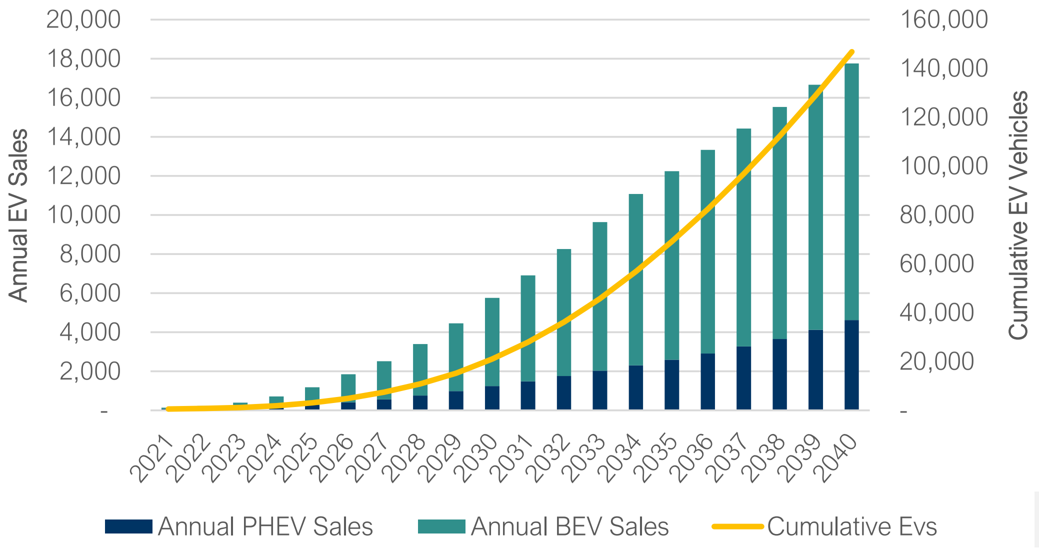
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2040)	Public / Workplace Level 2 (by 2040)	Home Charging Access in MURBs (by 2040)
Current federal incentives (phased-out by 2026)	100 Sites (400 Ports)	340 Sites (1,000 ports)	20%

Expanding current EV support efforts will increase EV adoption and BEV market share in Newfoundland and Labrador (NL); however, NL will still likely fall short of Federal ZEV targets.

- By 2040, a total of **150,000 EVs** of the 307,000 LDVs are forecasted to be on the road within the province
- EV adoption is expected to **fall short of the federal 2035 ZEV target** (100%), reaching only 48% of new sales by 2035.
- The increased deployment of local infrastructure **maintains the historical growth of BEV market share**, with BEVs representing ~75 % of all EVs on the road by 2040.





3. Light Duty Vehicles

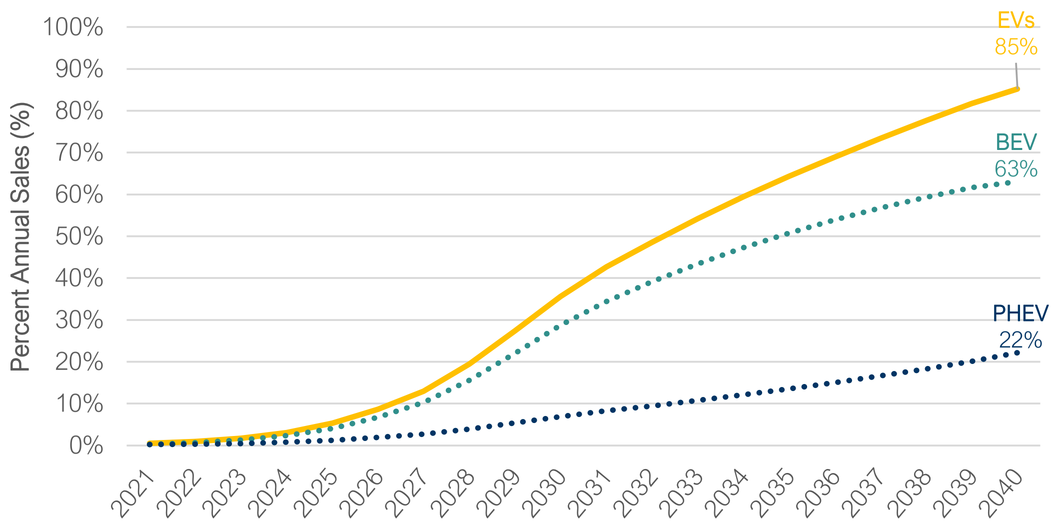
High Growth Scenario

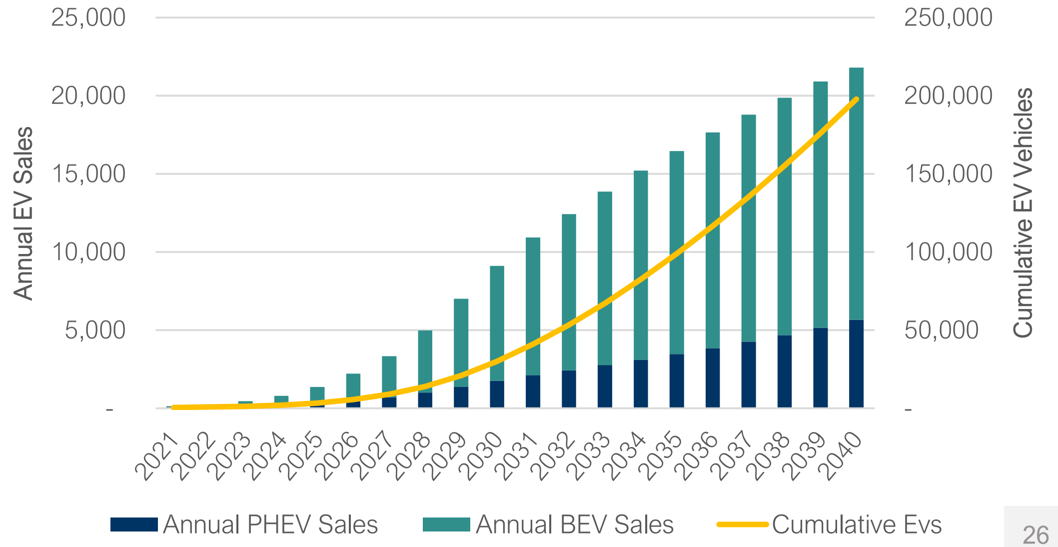
Policy/Program Interventions

Vehicle Incentives	Public DCFC (by 2040)	Public / Workplace Level 2 (by 2040)	Home Charging Access in MURBs (by 2040)
Current federal incentives (phased-out by 2035)	360 Sites (1,440 Ports)	400 Sites (1,600 ports)	45%

Aggressive expansion of public charging coupled with increased incentives, high EV local availability, and actions to increase home charging in MURBs would put Newfoundland and Labrador (NL) on trajectory to hit ZEV targets

- By 2040, a total of **198,000 EVs** of the 307,000 LDVs are forecasted to be on the road within the province
- EV adoption in NL would still not be expected to meet **the 2035 Federal ZEV Target of 100% of sales (65% annual sales)**
    - If the federal target is indeed locked-in, further interventions by government/industry actors may be required to address gaps





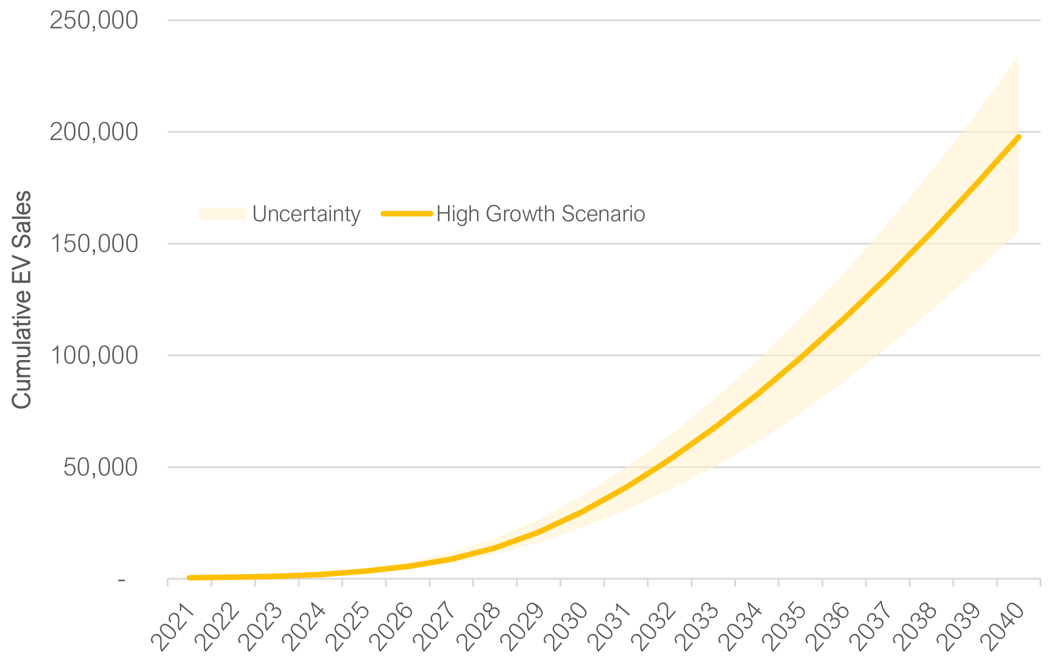
3. Light Duty Vehicles

Impacts of Uncertainty

Several key market and technology conditions will have an impact on the trajectory of EV adoption. For example, under the high growth scenario:

198,000 EVs on the road by 2040
(155k – 234k EVs)

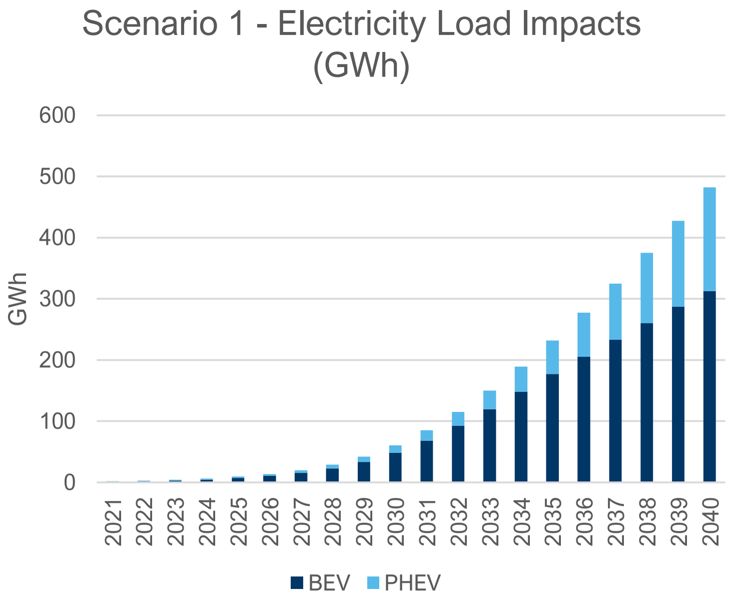
- Uncertainty around key factors could impact adoption upwards or downwards by as much as 22%.
- Dunsky's base case battery cost forecast is most conservative in early years due to uncertainty around the timing of achieving economies of scale for battery production and tends towards a more optimistic battery cost forecast in the 2030's when the market is expected to be well-established.
- The increasing uncertainty around the absolute number of EVs on the road over time largely reflects the underlying uncertainty around total vehicle sales (ICE and EVs) in the province in the future.

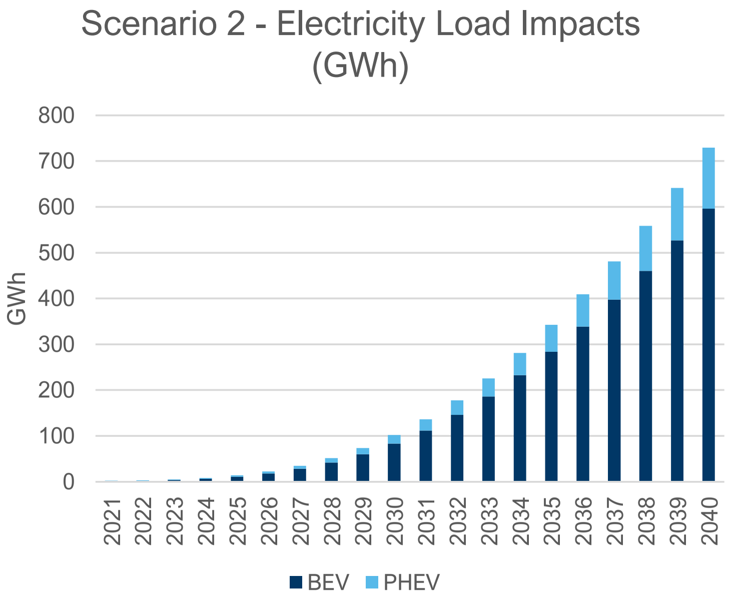


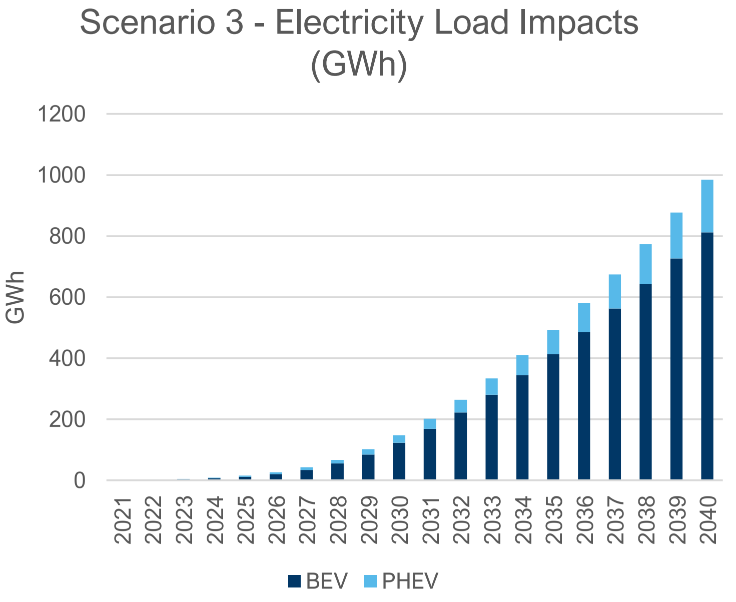
3. Light Duty Vehicles

Load Impacts

Light duty EV adoption will have a significant impact on load growth in Newfoundland and Labrador, increasing load by 480 – 1,000 GWh by 2040



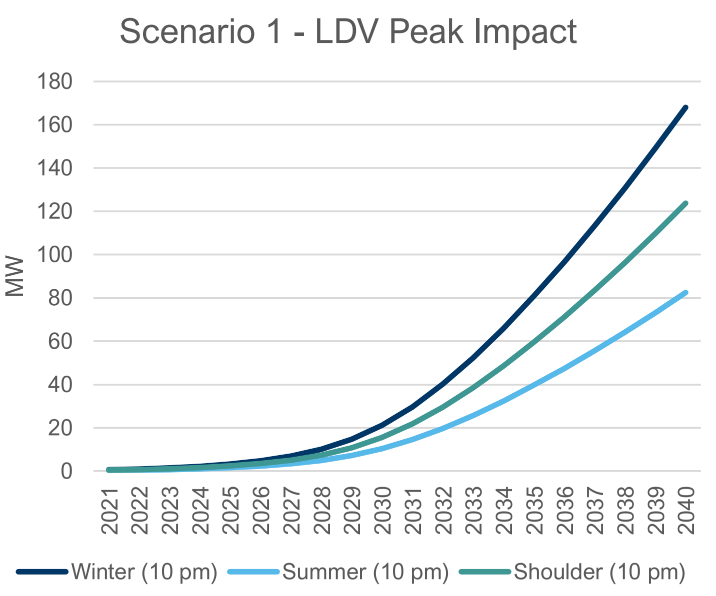


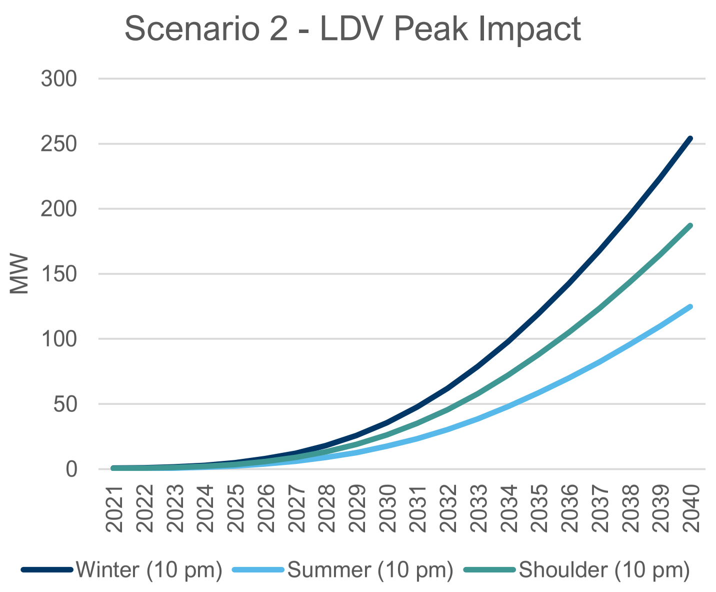


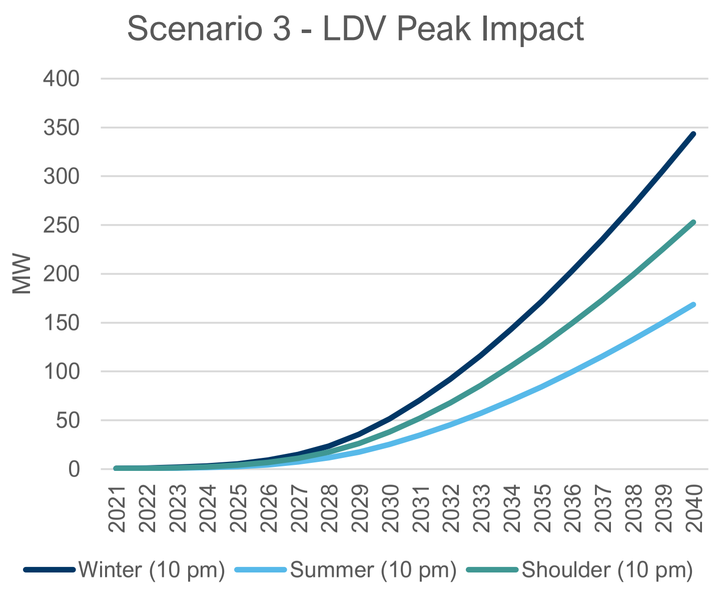
3. Light Duty Vehicles

Peak Day Impacts: Unmanaged

By 2040, light duty EVs will contribute 170 - 340 MW to peak demand in the winter at 10PM if unmanaged







3. Light Duty Vehicles

Managed Peak MW: High Growth Scenario (2040)

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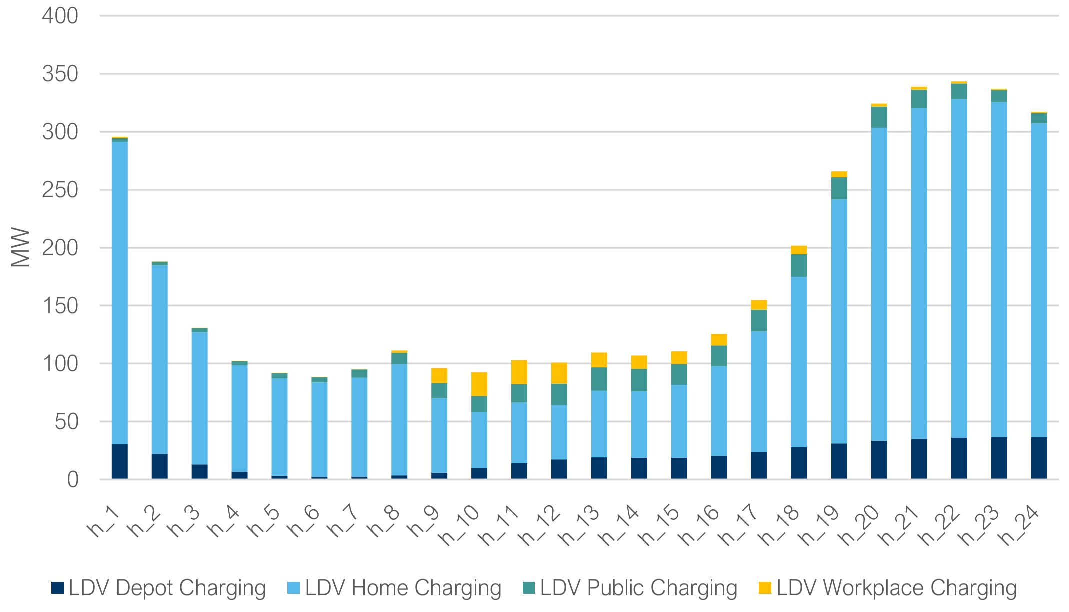
Home charging will impact winter peak loads the most significantly

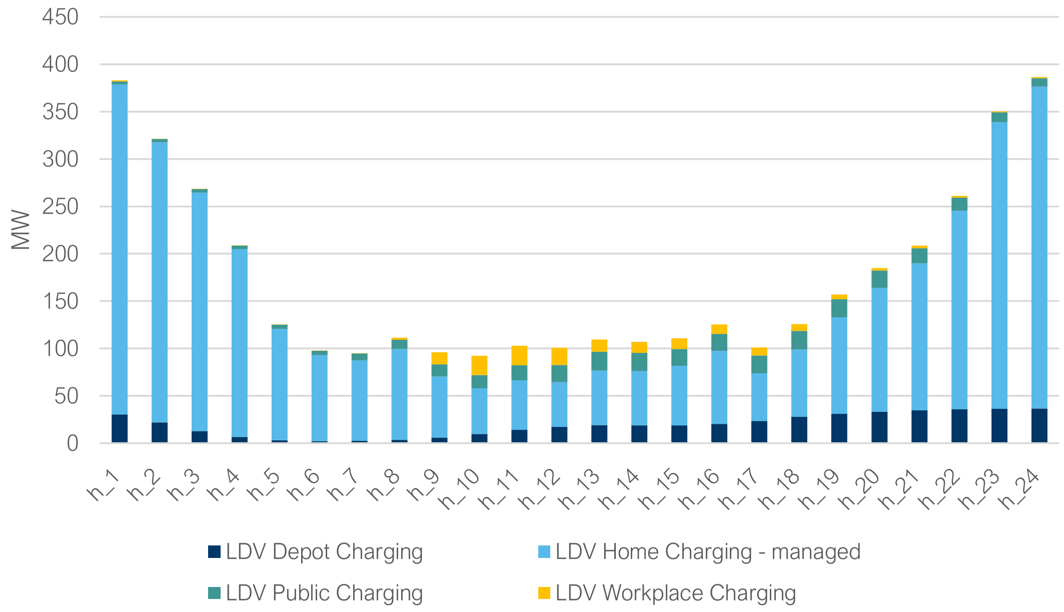
If unmanaged EV Peak load hour will be 10pm (340 MW), if managed that will shift to 1am (385 MW), depending on the load management strategy

***See Appendix for slides on additional scenario's**

Scenario 3 - 2040 Unmanaged Winter Peak Load Curve



Scenario 3 - 2040 Managed Winter Peak Load Curve



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4. Medium & Heavy Duty Vehicles

4.1 Provincial Scenarios
4.2 Regional Impacts
4.3 Provincial Results

4. Medium & Heavy Duty Vehicles

MHDV Scenarios and Sensitivities

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Three scenarios reflecting likely trajectories for EV adoption in Newfoundland and Labrador under varying policy, technology and market conditions

	Scenario 1: Low Growth	Scenario 2: Moderate Growth	Scenario 3: High Growth
Vehicle Incentives	None	25% of incremental cost, up to $75k *(Ramped down and phased-out by 2026)*	50% of incremental cost, up to $150k *(Ramped down and phased-out by 2030)*

	Low Sensitivity Scenario (Most Conservative)	Base Case	High Sensitivity Scenario (Most Aggressive)
Battery Costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV Model Availability	High availability of most models by 2030	High availability of most models by 2028	High availability of most models by 2024
Charging Power (for HDVs)	Up to 350 kW Charging (Varies by vehicle segment)	Up to 1 MW Charging (Varies by vehicle segment)	Up to 2 MW Charging (Varies by vehicle segment)
Electricity Cost Escalation	1% higher than historical	Historical levels *(≈ 3% per year)*	1% lower than historical
Fuel Price Escalation	Historical escalation	Historical escalation (≈ 2% per year) + $170/ton carbon tax by 2030	Historical escalation (≈ 2% per year) + $170/ton carbon tax by 2030

4. Medium & Heavy Duty Vehicles

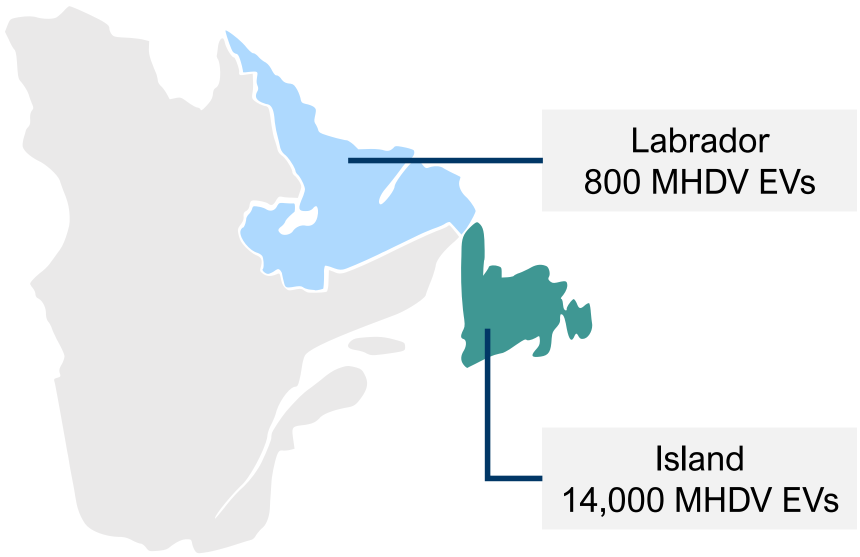
Regional Disaggregation

For commercial fleets, no differences in market penetration across regions was assumed, and results were disaggregated using number of registered vehicles in each area.

- Similar to the LDV market the vast majority of EVs are found in the Mainland (~95%) due to population/vehicle distributions

The following results in the report are at the provincial level and more detailed regional outputs can be found in the Excel-based results dashboard

2040 High Scenario - MHDVs

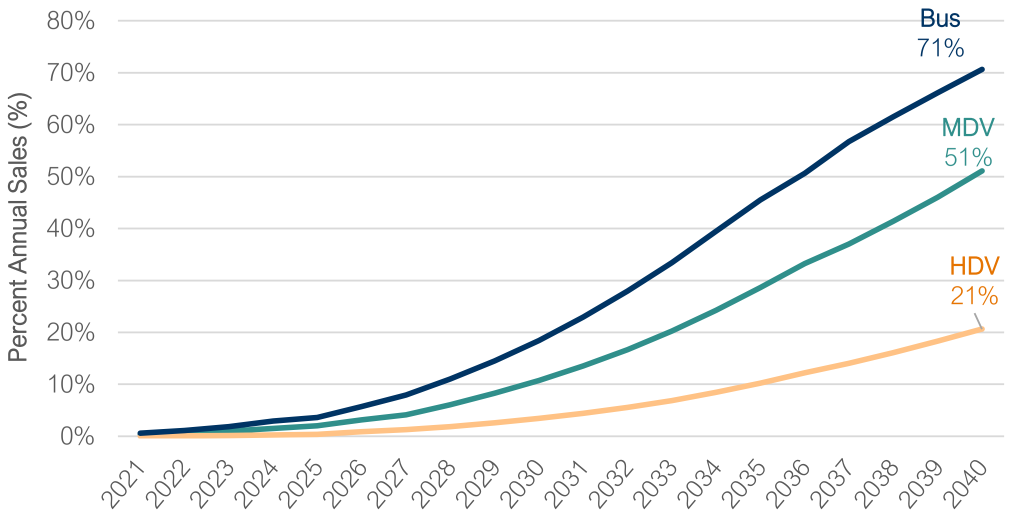


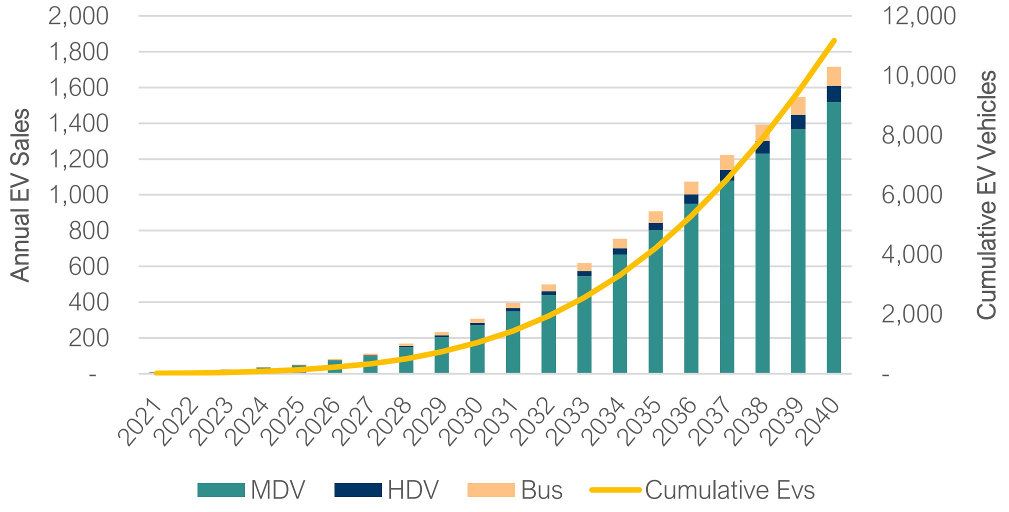
4. Medium & Heavy Duty Vehicles

Low Growth Scenario

Under the Low Scenario, Newfoundland and Labrador will experience varying growth in EV uptake for different vehicle segments.

- MDV trucks will lead the cumulative MHDV market **(51% annual sales and 10,000 cumulative sales by 2040)** – this market segment is largely comprised of urban/regional delivery vehicles that benefit from a strong business case for electrification thanks to consistent daily usage with high overall annual driving distances
- The bus segment is expected to be the most promising in annual sales, reaching **71% annual sales by 2040**
- The HDV truck segment is expected to observe the lowest EV demand **(21% annual sales by 2040)** due to a portion of the HDV truck market focused on either long-haul or other vocational applications (e.g., dump trucks) with greater technical challenges (i.e., range and payload requirements)



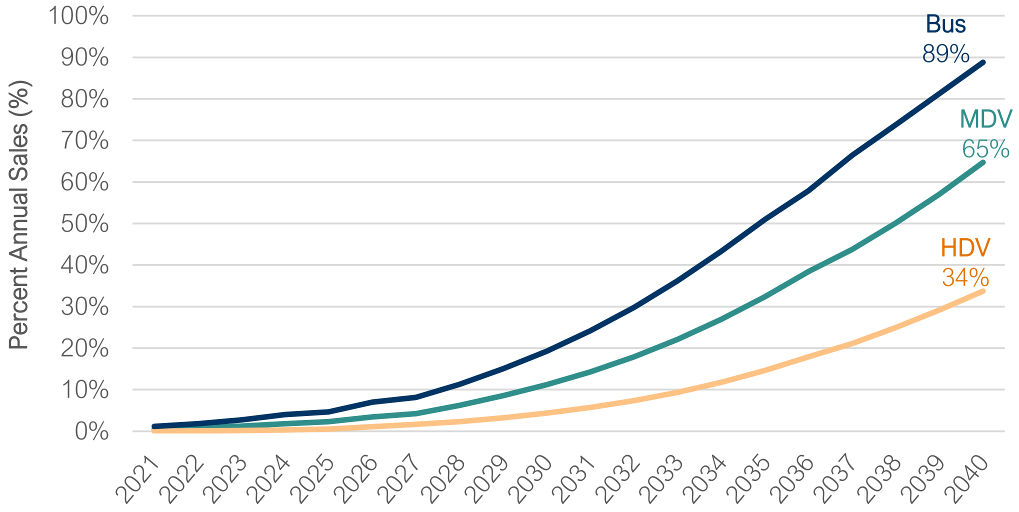


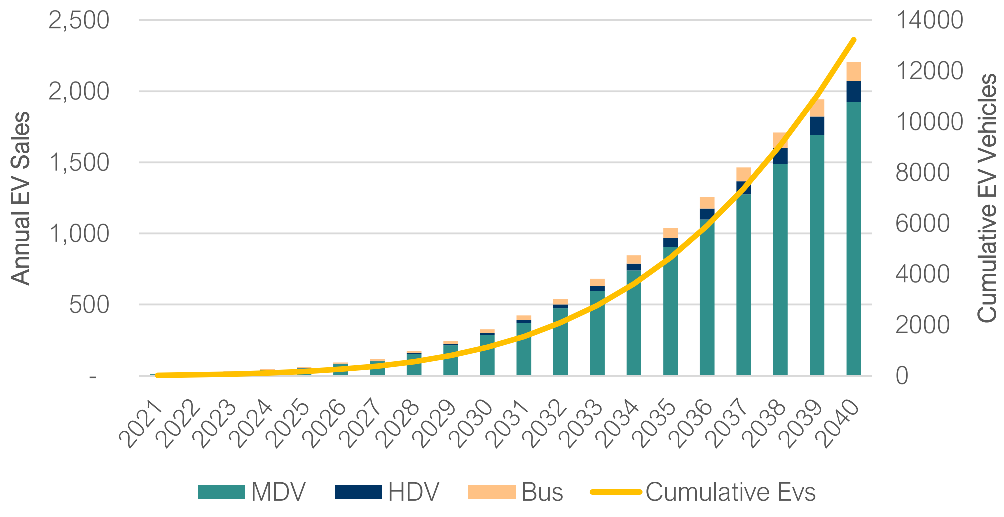
4. Medium & Heavy Duty Vehicles

Medium Growth Scenario

Under the Medium Scenario, Newfoundland and Labrador will experience modest growth in EV uptake.

- Vehicle incentives for MHDV segments improve the economics across all vehicle segments
- Like the low scenario, there will be varying growth in EV uptake for different vehicle segments.
- HDVs see a significant increase in market share due to the availability of megawatt-scale fast charging capabilities assumed under this scenario.



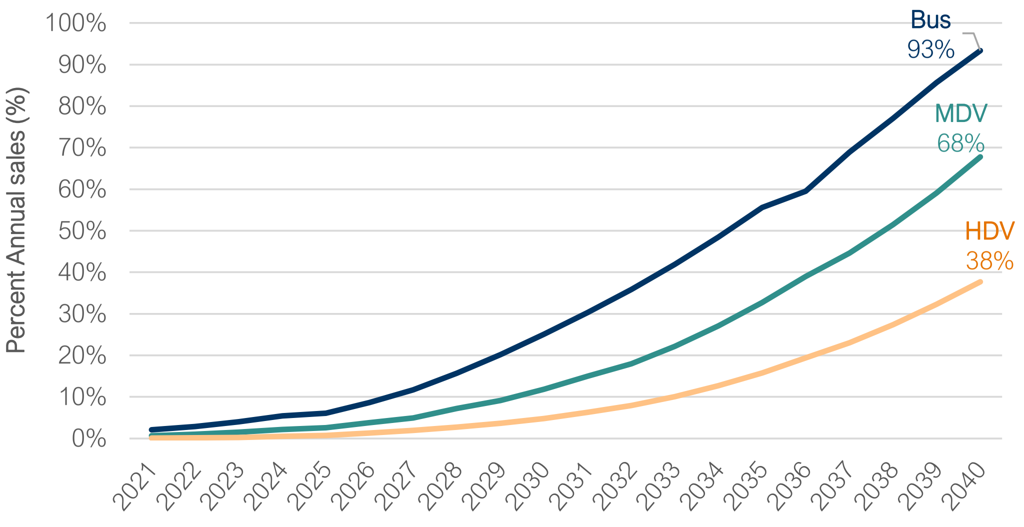


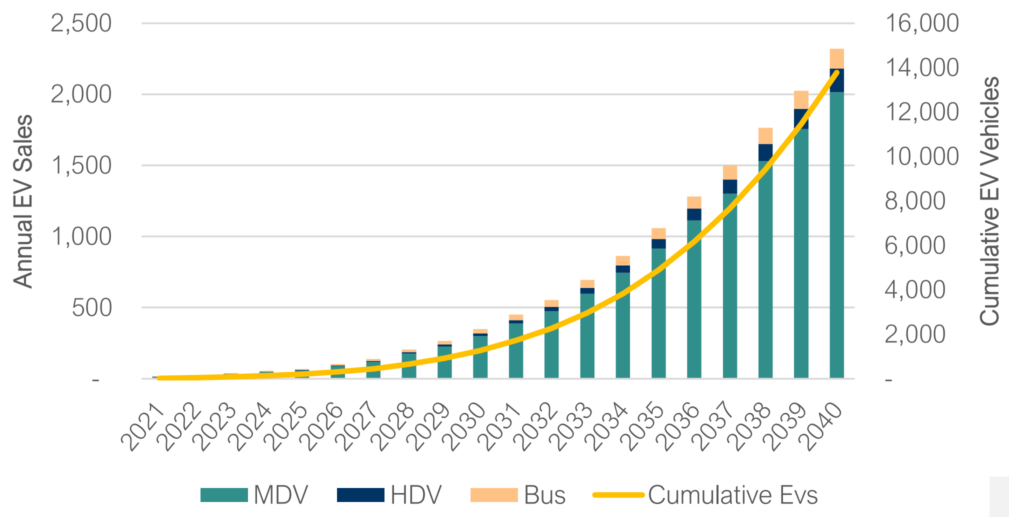
4. Medium & Heavy Duty Vehicles

High Growth Scenario

Under the High Scenario, Newfoundland and Labrador will experience high growth in EV uptake.

- Vehicle incentives for MHDV segments improve the economics across all vehicle segments
- Like the low and medium scenario, there will be varying growth in EV uptake for different vehicle segments.

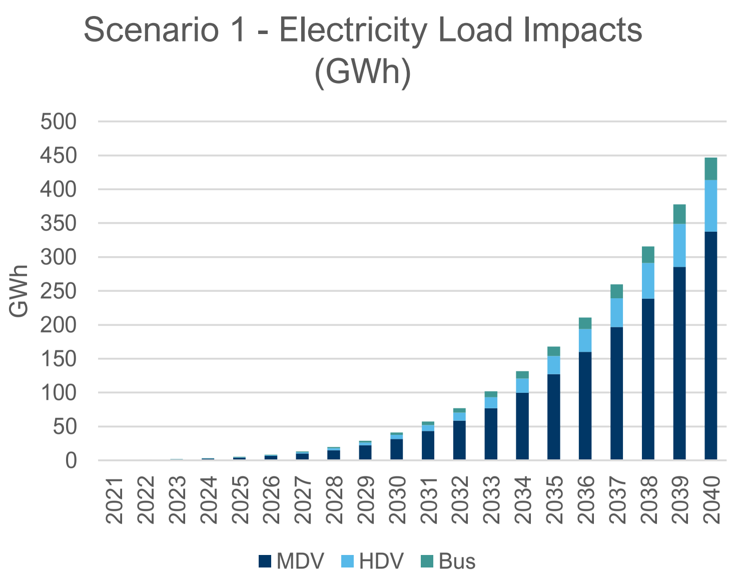


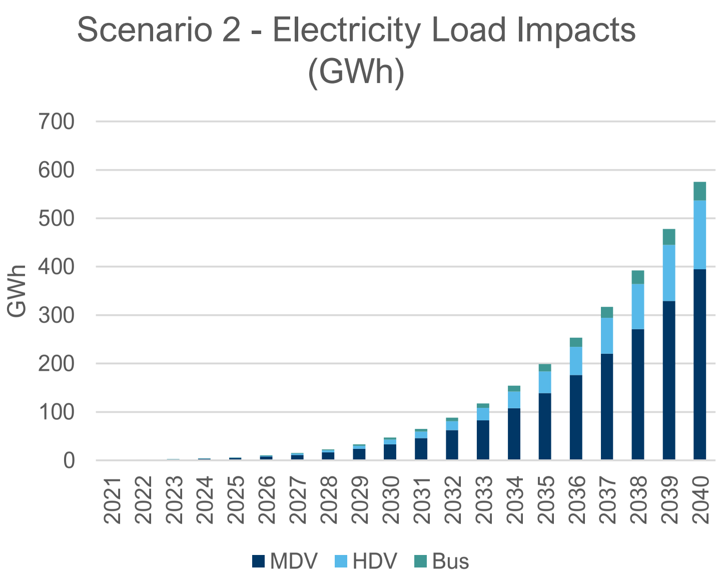


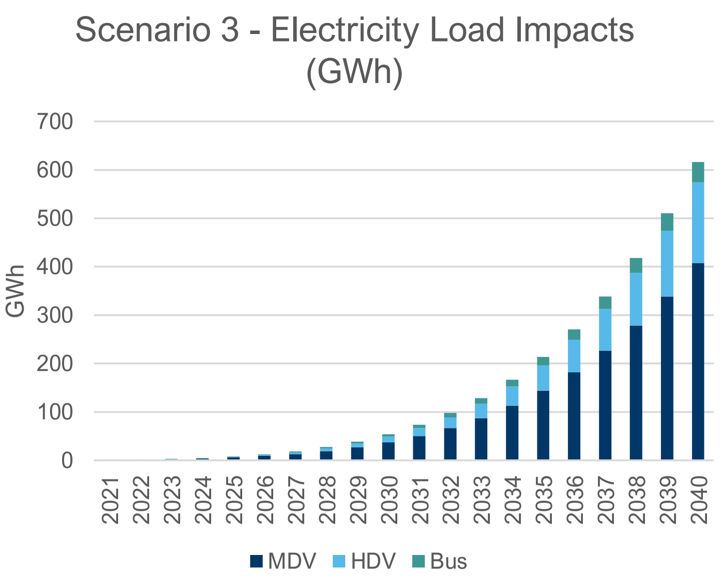
4. Medium & Heavy Duty Vehicles

Load Impacts

MHDV EV adoption will have a significant impact on load growth in Newfoundland and Labrador, increasing load by 450 – 615 GWh by 2040



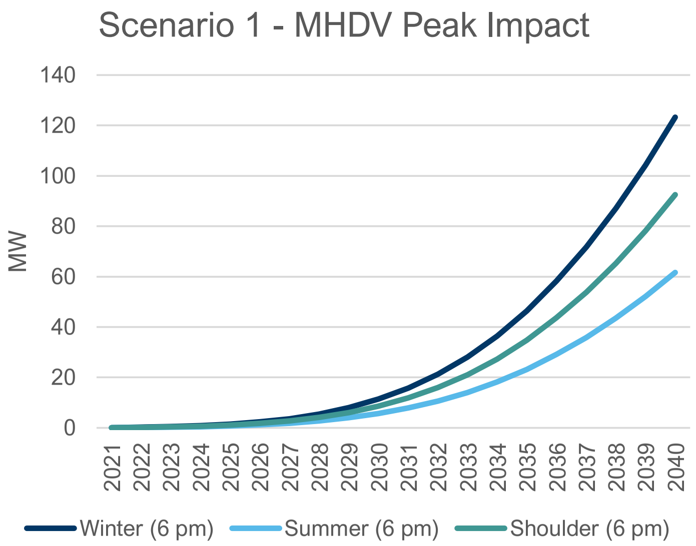


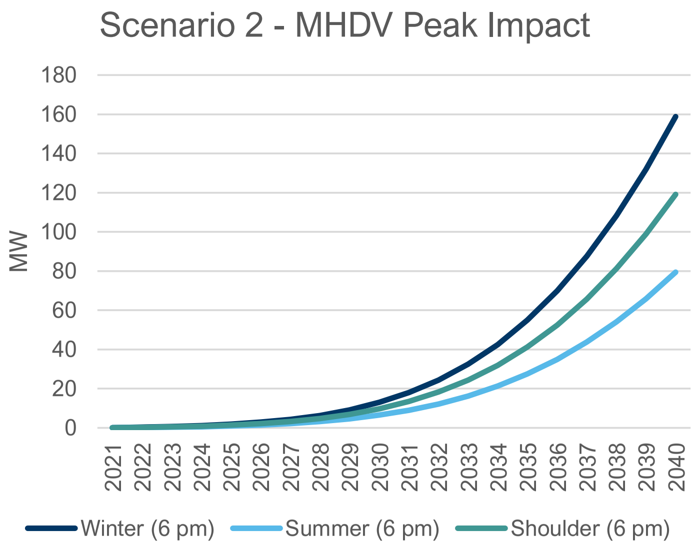


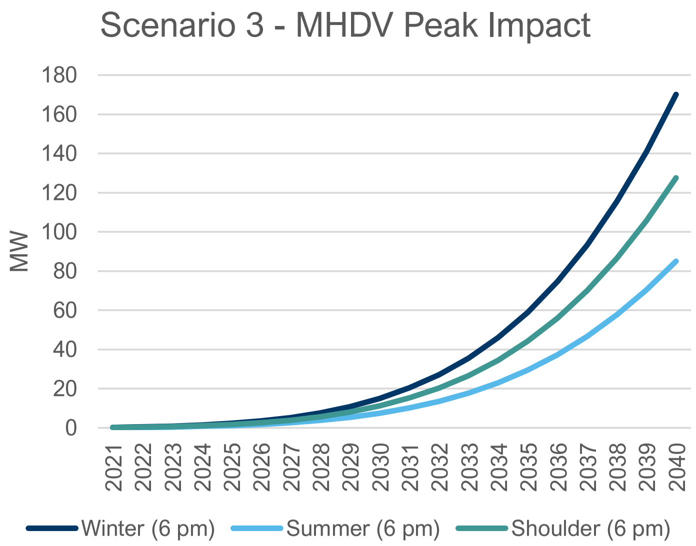
4. Medium & Heavy Duty Vehicles

Peak Day Impacts

By 2040, MHDV EVs will contribute 125 - 175 MW to peak demand in the winter at 6PM





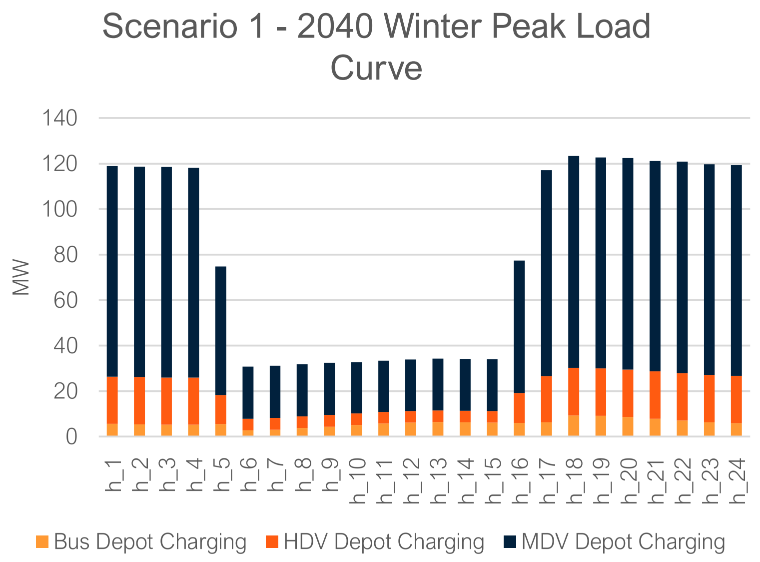


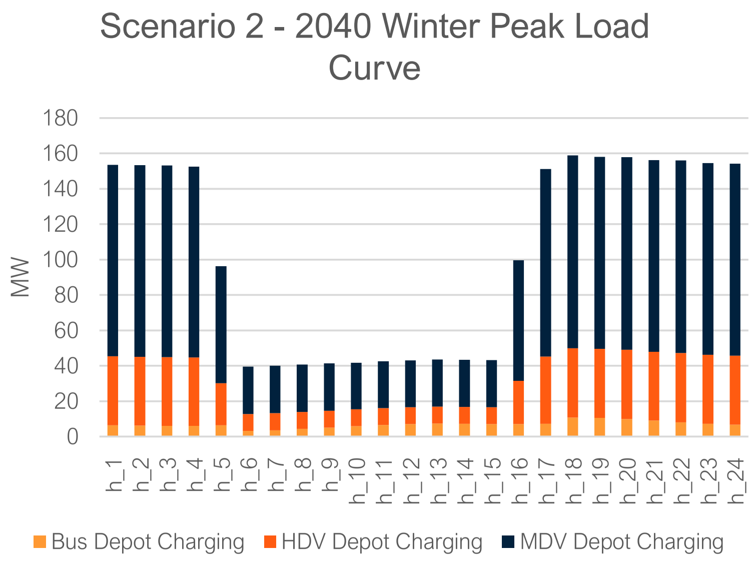
4. Medium & Heavy Duty Vehicles

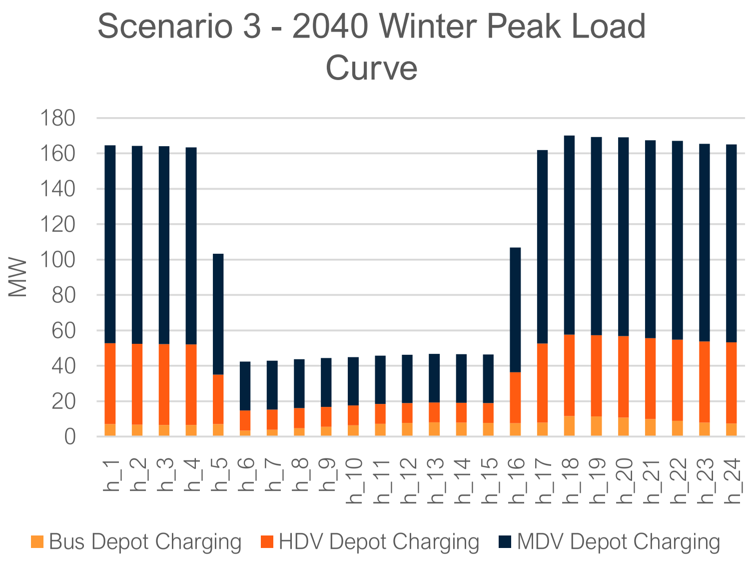
Peak Day Hourly Load Profiles (2040)

MHDV charging will impact winter peak MW's the most significantly

Peak hour will be 6pm for winter, summer, and shoulder. Load profiles for MHDV fleets are less flexible, with vehicles and infrastructure designed based on range requirements and the available charging window







5. Conclusion

EV Adoption Potential

While these results present a wide range of possible outcomes, the overall scale of the EV transformation in Newfoundland and Labrador is significant under all scenarios, with between 100,000 and 200,000 light-duty EVs expected to be circulating in the province by 2040.

A further 10,000 to 14,000 medium- and heavy-duty (MHDV) EVs are likely to enter service by 2040, with a number of MHDV segments seeing strong potential for electrification (e.g. buses, medium-duty delivery trucks), while others have greater uncertainty based on technology progress (e.g. long-haul heavy-duty trucks).

While this growth in EV adoption in NL is significant, we anticipate that EV adoption in Newfoundland and Labrador will continue to lag behind the rest of Canada, achieving 65% of new LDV sales by 2035 in the High scenario.

Load Impact

EVs could generate up to **1,600 GWh in electricity sales in 2040**; however, if EV charging loads are left unmanaged they could **increase system peak loads** by as much as **525 MW** in the same year.

Personal light-duty EVs present the most promising opportunities for managed charging, with a variety of options for mitigating peak load impacts from EVs and providing benefits from EVs as flexible loads.

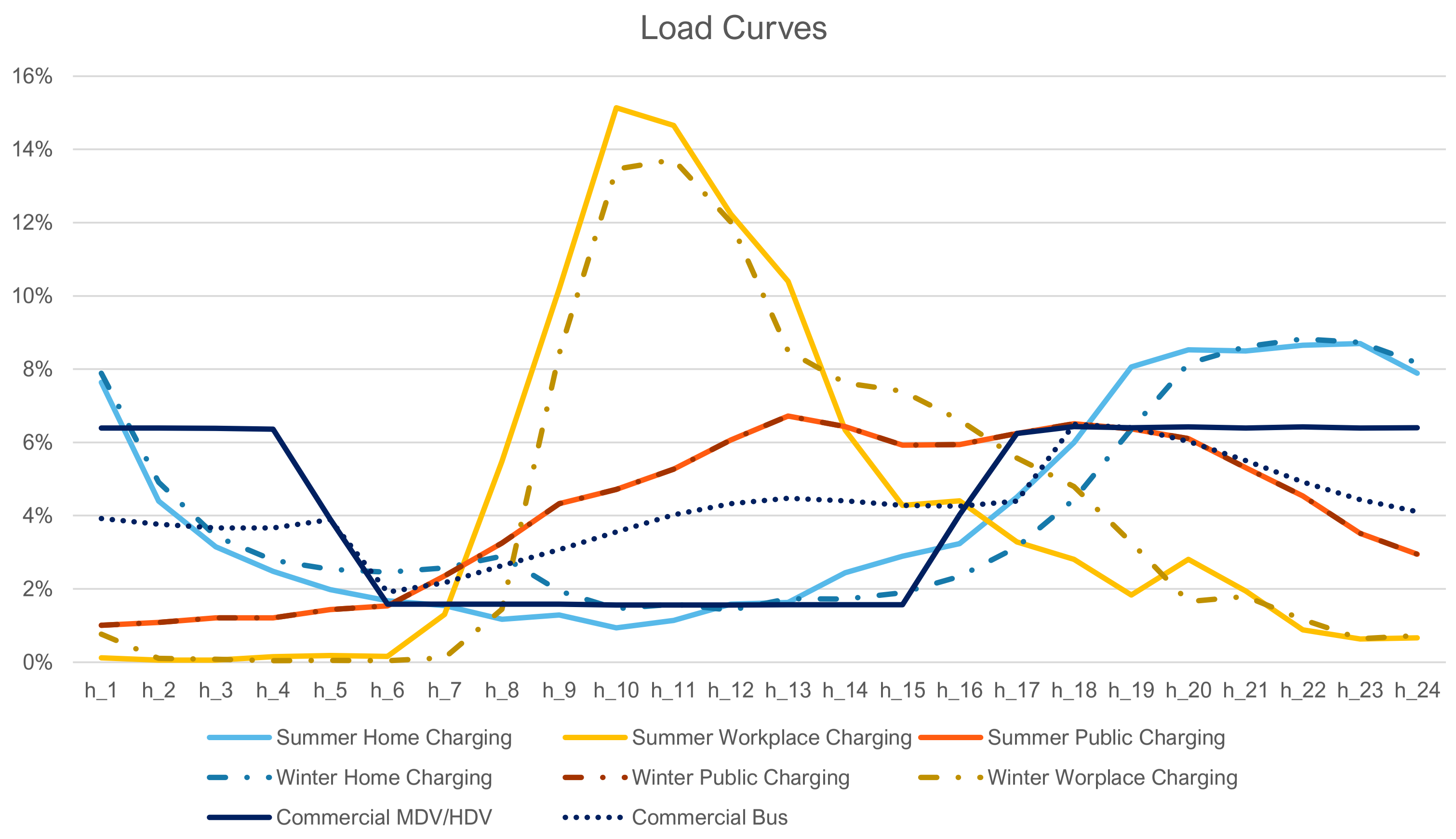
While medium- and heavy-duty EVs represent a much smaller number of vehicles, their size means that they contribute disproportionately to load growth. Many MHDV fleets will see a large number of vehicles charging in a single facility, motivating fleet operators to spread charging over as much time as possible and minimize peak loads within their own facilities.

Appendix

Appendix

Normalized Load Curves

The normalized load curves below outline the anticipated hourly load by charging type for both summer and winter conditions. These curves are used to project hourly load.



Appendix

Key Resources

Key Data Source	Use
Natural Resource Canada (NRCan), Comprehensive Energy Use Database (CEUD)	Province-wide vehicle sales and registrations, segment split (Car, Truck, SUV)
Community Accounts Unit Newfoundland and Labrador Hydro and Statistics Canada	Total Electric vehicle sales and BEV/PHEV split
Statistics Canada	Population, area of population centers, housing composition, driving distance, fuel prices
Newfoundland and Labrador Hydro	Electricity rates
Natural Resource Canada (NRCan) - Electric Charging and Alternative Fueling Stations Locator	Charging station deployment
Internal Dunsky Database	2020 vehicle cost, vehicle characteristics & projected EV model availability, battery costs

Appendix

Key Inputs

Vehicle	NRCan kwh/km	Vehicle Lifetime	Average Annual Driving Distance*
Car	0.21	11	19,000
SUV	0.26	11	19,000
Light-truck	0.29	11	19,000
MDV	0.80	16	30,000
HDV	1.24	20	120,000
Buses	1.20	16	22,000

*weighted averages for MDV and HDV segments reflect the sub segments that are more likely to electrify due to higher drive cycles.

Appendix

LDV: Key Inputs and Sensitivities

Gas Prices ($/Litre)

	2021	2025	2030	2035	2040
Low	$1.464	$1.612	$1.819	$2.052	$2.316
Mid	$1.464	$1.831	$2.210	$2.443	$2.707
High	$1.464	$1.831	$2.210	$2.443	$2.707

Average Electricity Prices ($/kWh)

	2021	2025	2030	2035	2040
Low	$0.160	$0.179	$0.200	$0.223	$0.250
Mid	$0.160	$0.181	$0.202	$0.226	$0.252
High	$0.160	$0.183	$0.204	$0.228	$0.255

Battery Costs ($/kWh)

	2021	2025	2030	2035	2040
Low	$296	$160	$80	$62	$48
Mid	$296	$217	$147	$99	$75
High	$296	$270	$209	$161	$121

*Average electricity prices were calculated based on historic delivered cost rates.

Annual New Vehicle Sales (Rounded to Nearest 10)

(Included both passenger and commercial LDVs, with commercial fleets assumed to make up 11% of sales)

		Low	Medium	High
Car	2021	11,440	11,440	11,440
	2025	10,990	11,440	11,910
	2030	10,450	11,440	12,520
	2035	9,940	11,440	13,150
	2040	9,450	11,440	13,830
SUV	2021	9,760	9,760	9,760
	2025	9,370	9,760	10,160
	2030	8,910	9,760	10,670
	2035	8,480	9,760	11,220
	2040	8,060	9,760	11,790
Truck	2021	4,340	4,380	4,430
	2025	4,210	4,380	4,560
	2030	4,000	4,380	4,790
	2035	3,810	4,380	5,040
	2040	3,620	4,380	5,300

Other inputs

	Value (2020)
Province Population	521,500
Population in centres with >1,000 people	384,500
Number of Population centres with >1,000 people	63
Estimated Land area of Population centres (sq. km)	400
Highway length (km)*	2,000

*The value represents an estimate of the length of highways within the state that need to be covered by charging infrastructure deployment based on data on length of key interstate highways, freeways, expressways and principal arterial roads.

Appendix

MHDV: Key Inputs and Sensitivities

Diesel Prices ($/Litre)

	2021	2025	2030	2035	2040
Low	$1.457	$1.577	$1.742	$1.923	$2.123
Mid	$1.457	$1.834	$2.201	$2.382	$2.582
High	$1.457	$1.834	$2.201	$2.382	$2.582

Average Electricity Prices ($/kWh)

	2021	2025	2030	2035	2040
Low	$0.136	$0.152	$0.170	$0.190	$0.213
Mid	$0.136	$0.154	$0.172	$0.192	$0.214
High	$0.136	$0.156	$0.173	$0.194	$0.217

Battery Costs ($/kWh)

	2021	2025	2030	2035	2040
Low	$296	$160	$80	$62	$48
Mid	$296	$217	$147	$99	$75
High	$296	$270	$209	$161	$121

*Average electricity prices were calculated based on historic delivered cost rates.

Annual New Vehicle Sales (Rounded to Nearest 10) - MHDV

	Segment	2021	2025	2030	2035	2040
MDV	Urban Delivery	1,590	1,590	1,620	1,660	1,690
	Utility Vehicle	7,280	7,280	7,290	7,300	7,310
HDV	Short-Haul	90	90	100	100	100
	Long-Haul	1,900	1,910	1,910	1,910	1,910
	Other	110	110	110	110	110
Bus	Transit	80	80	80	90	90
	School	260	260	260	260	260
	Coach	20	20	20	20	20

Appendix

EVA Model: Methodology Overview

EVA projects market adoption based on four key factors:

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, SUVs, pickups)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/EV over ICE vehicles
- Total Cost of Ownership (TCO) (personal) or Internal Rate of Return (IRR) (commercial) based on operational and fuel costs

CONSTRAINTS

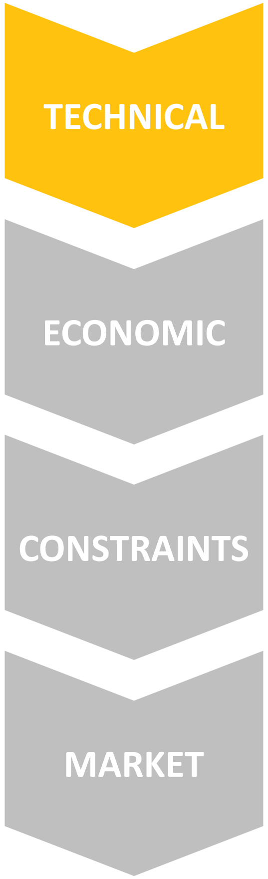
Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access, others

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between vehicles types (PHEV vs. BEV)

Appendix

EVA Model: Technical

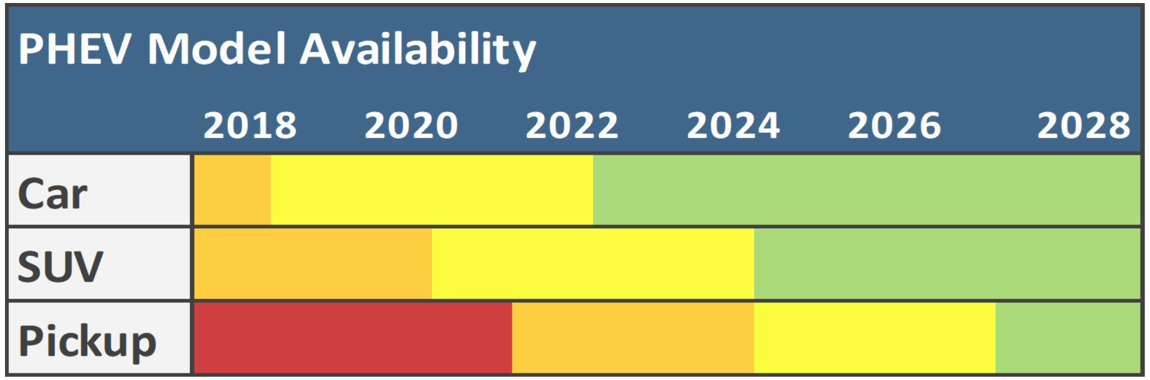


Assess the maximum theoretical potential for deployment

The model breaks down vehicles by segments (i.e. cars, SUVs, trucks, etc.) **and powertrain** (ICE, PHEV, BEV) with each class-powertrain being represented by an ***average*** vehicle option

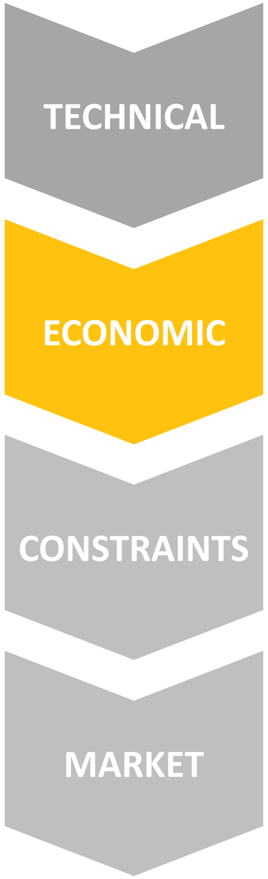
Annual sales for each vehicle class represents 100% of attainable market
- Capture growth in forecasted vehicle sales and changing trends between vehicle segments

Model availability for each vehicle powertrain in each vehicle class is key



Appendix

EVA Model: Economic



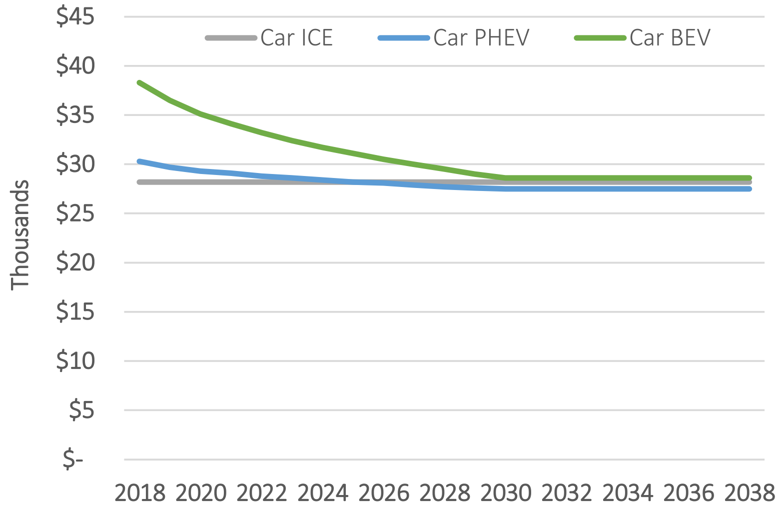
Calculate unconstrained economic potential uptake

For each vehicle class and powertrain, vehicle cost is assessed bottom-up:
- Baseline vehicle cost
- ICE Powertrain cost
- Electric Powertrain Cost
- Battery Cost – based on BNEF and EIA forecasts[1]

For each vehicle class, Total Cost of Ownership (TCO) is based on
- Incremental Upfront cost of PHEV/BEV over ICE
- Lifetime operational cost savings incremental to ICE

Estimate unconstrained economic market potential based on identified willingness-to-pay from survey and research results

Sample EV cost decline scenario based on BNEF battery cost forecast



[1]Bloomberg New Energy Finance “EV Outlook 2018” and U.S. Energy Information Administration “Annual Energy Outlook 2018”

Appendix

EVA Model: Constraints

Account for jurisdiction-specific barriers and constraints

Market Constraining Factors include:

- **Range anxiety:** Capture the portion of the market that is constrained by the limited range of BEVs (does not apply to PHEVs)
- **Home Charging Availability:**
  - Given the importance of access to charging at home, EV adoption is constrained to the portion of the market where charging stations can readily be installed.
    - Building type (i.e. single-family vs. multi-family)
    - Percentage of each building type with access to charging (or driveways/dedicated parking)
  - Constraint can be reduced over time through targeted incentive programs and building code changes.

Appendix

EVA Model: Constraints

TECHNICAL
ECONOMIC
CONSTRAINTS
MARKET

… *(cont'd)* Account for jurisdiction-specific barriers and constraints

Public Charging constraints are captured in two ways:

- **Coverage** captures the geographical coverage of charging infrastructure by contrasting the number of stations deployed to the required number of stations regionally considering:
  - *Number of stations required along key **highway corridors** across the region to alleviate charging barriers for potential EV adopters based on highway lengths and typical station spacing.*
  - *Number of stations required in **population clusters** (defined as population centers with > 10,000 people) to achieve at least one charging station per cluster and ensure that drivers have access to a charger within a reasonable radial distance.*
- **Charging Availability** captures the availability and power of charging ports and corresponding charging time
  - *Captured as EVs per Port ratio (for L2 and DCFC)*
  - *"Ideal" ratio calculated based on*
    - Population density in key population centers across the region
    - EV Density in key population centers across the region
    - Annual average temperatures
    - Home charging access
  - *Dynamic relationship with EVs of the road*

Station

Port

Appendix

EVA Model: Market

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TECHNICAL

ECONOMIC

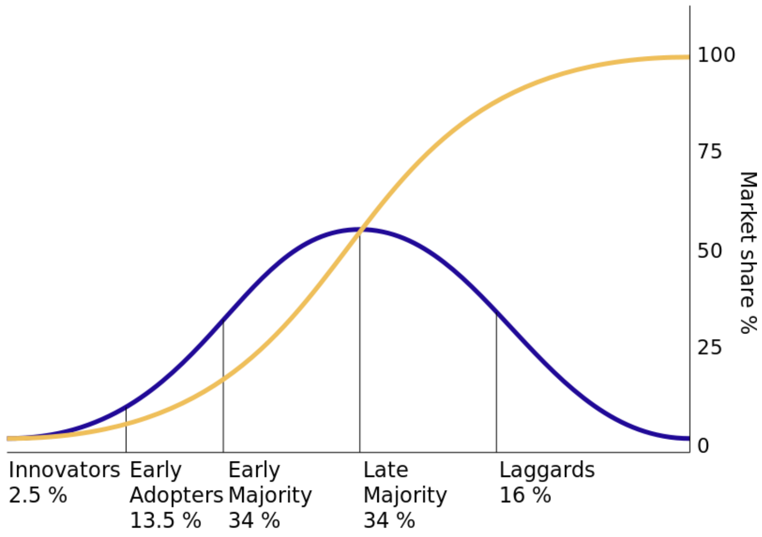
CONSTRAINTS

MARKET

Incorporate market dynamics and non-quantifiable market constraints

Estimate rate of market adoption using technology diffusion theory

- Captures the degree to which the market adopts new innovative technologies over time
- Accounts for the demographics and composition of market through segmenting potential adopters into five categories that vary by motivation for adoption (environmental, economic, etc.), willingness to take risks, technology understanding and other factors.
- Accounts for social interactions and public awareness (or lack of) and impact of programs on increasing awareness.



Appendix

EVA Model: Market

… *(cont'd)* Incorporate market dynamics and non-quantifiable market constraints

TECHNICAL

ECONOMIC

CONSTRAINTS

MARKET

PHEVs and BEVs are assumed to compete for the same market

- After comparing technical, economic, constrained and market potential of both technologies, a probabilistic function is used to assume a portion of the market will not be rational and will adopt the inferior of the two options, considering historical trends in the market.
- Certain policies/programs can have the effect of shifting the market from one technology to the other without necessarily impacting overall EV market share.

Appendix

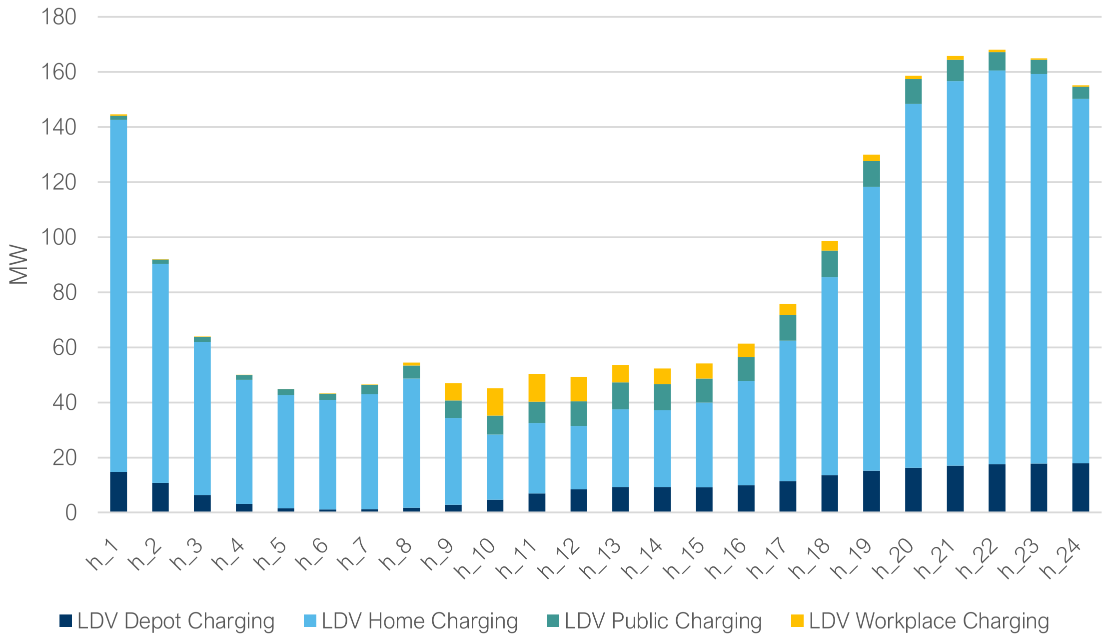
Managed Peak MW: Low Growth Scenario (2040)

dunsky

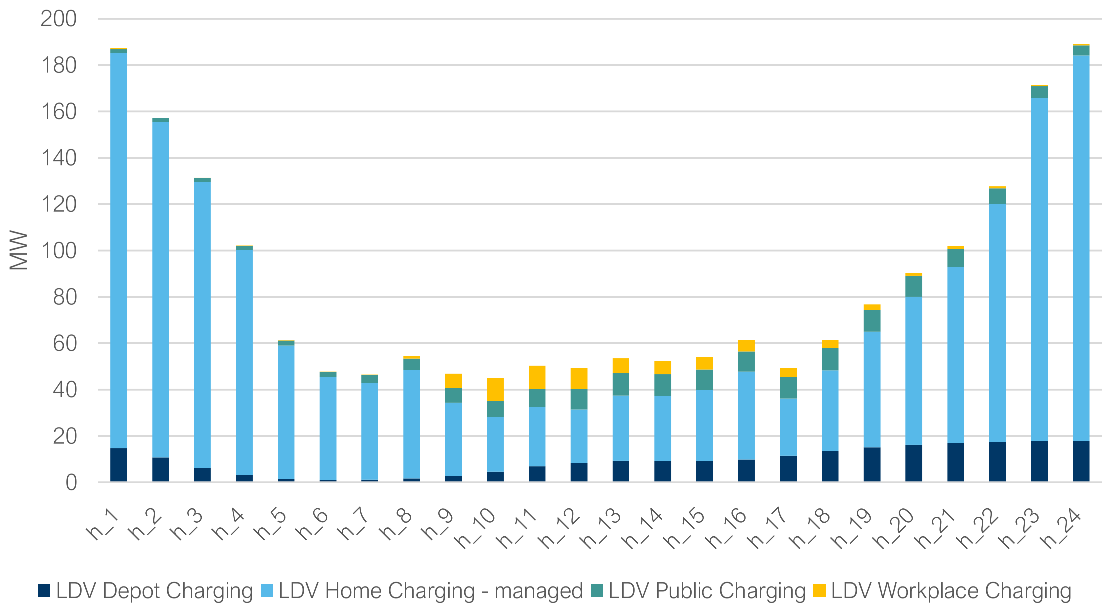
Home charging will impact winter peak MW's the most significantly

If unmanaged EV Peak load hour will be 10pm (170 MW), if managed that will shift to midnight (190 MW)

Scenario 1 - 2040 Unmanaged Winter Peak Load Curve



Scenario 1 - 2040 Managed Winter Peak Load Curve



Appendix

Managed Peak MW: Medium Growth Scenario (2040)

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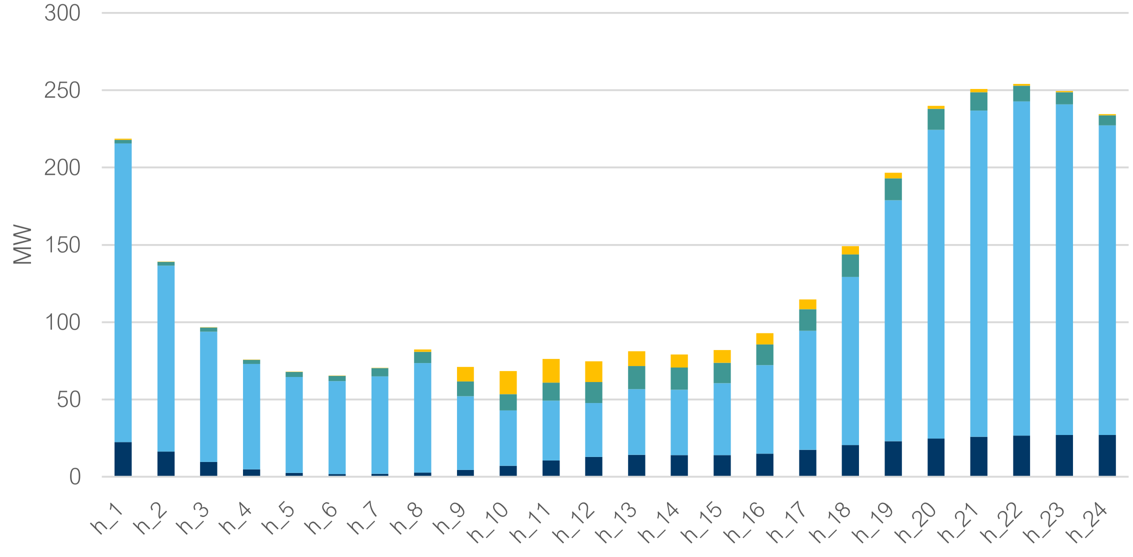
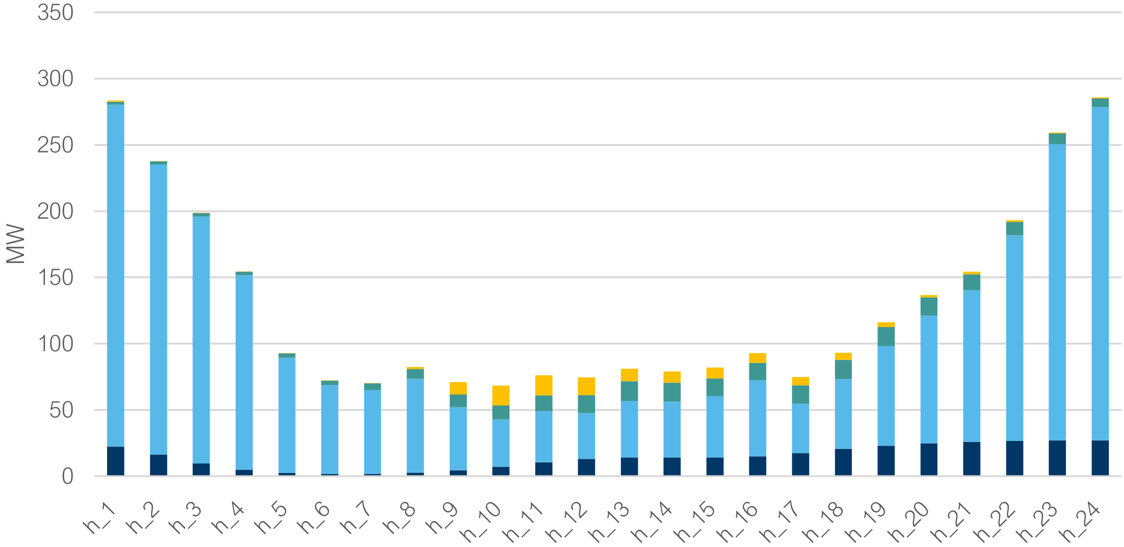
Home charging will impact winter peak MW's the most significantly

If unmanaged EV Peak load hour will be 10pm (250 MW), if managed that will shift to 1am (280 MW)

Scenario 2 - 2040 Unmanaged Winter Peak Load Curve



Scenario 2 - 2040 Managed Winter Peak Load Curve



Appendix

Managed Peak MW: High Growth Scenario (2040)

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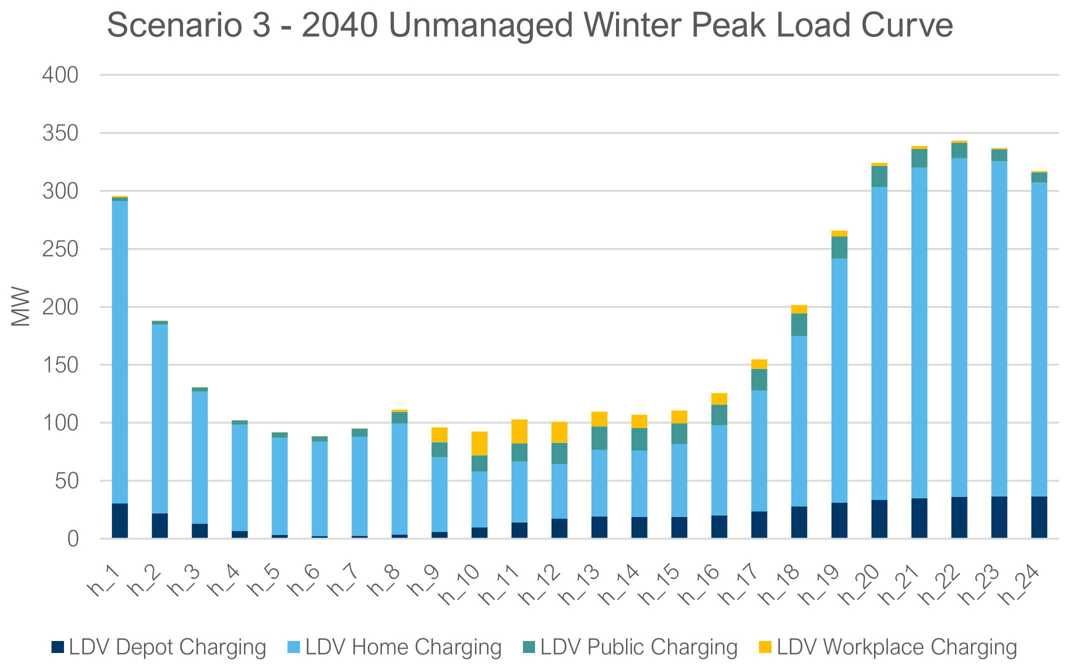
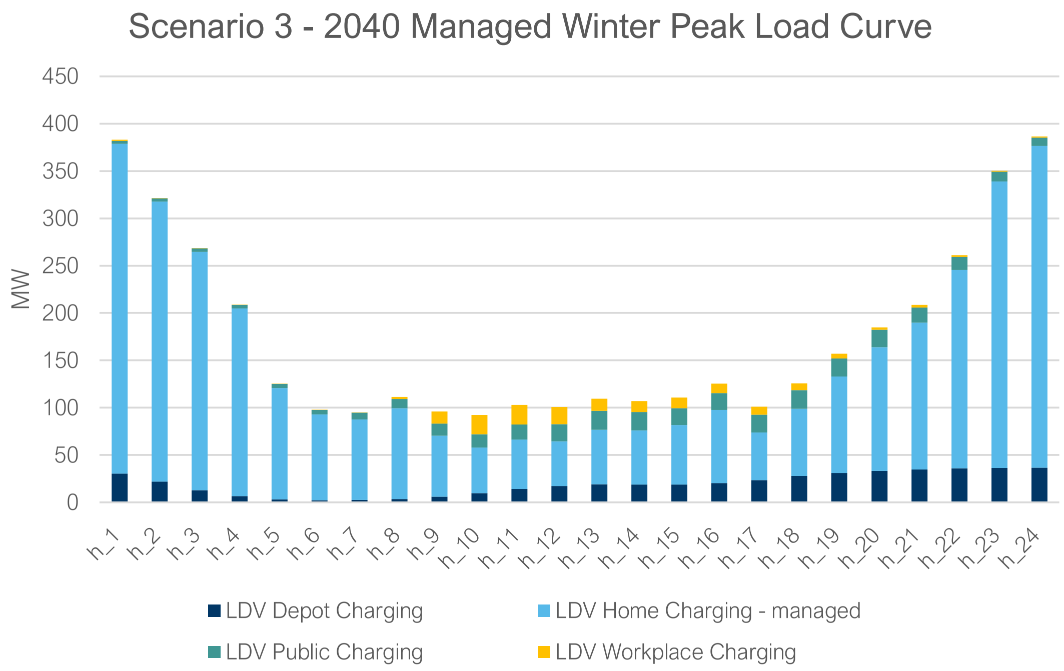
Home charging will impact winter peak loads the most significantly

If unmanaged EV Peak load hour will be 10pm (340 MW), if managed that will shift to 1am (385 MW), depending on the load management strategy

***See Appendix for slides on additional scenario's**





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Volume III, Attachment 3

Independent Review of Hydro's Load Forecast 2022

newfoundland labrador hydro

DAYMARK ENERGY ADVISORS

MEMORANDUM

TO: Newfoundland Labrador Hydro

FROM: Daymark Energy Advisors

DATE: August 30, 2022

SUBJECT: Independent Review of Hydro's Load Forecast 2022

Introduction / Current Situation

- Hydro is preparing its R&RA for submission to regulators and a key underpinning of the analysis requires a projection of energy and capacity needs to compare to the available resources particularly when considering peak and extreme weather periods
- Load forecasting must consider not only a reference or base case but also provide additional "cases" or "scenarios" or "futures" that incorporate the multiple uncertainties inherent in forecasting that address the economy and consumer response to economic changes, weather impacts under climate change that may differ from historic, new load attraction, customer retention, provincial policies that may impact electricity demand such as EV adoption or electrification or the "Network Additions Policy" (NAP) and industrial attraction to enhance economic growth – there are many uncertainties that are difficult to forecast but such potential modifications to resource need must be assessed in the R&RA process.

Scope of Engagement

- As part of our independent review of the R&RA methodologies, Daymark reviewed the R&RA analytical methodology and as part of that effort also the forecast methodology to assess its base and alternative forecasting methodology and potential for load requirements. In addition, we investigated how Hydro addresses the many uncertainties and brackets the scenarios to address potential energy need to better inform planning and actions recommended.

Methodology Approach

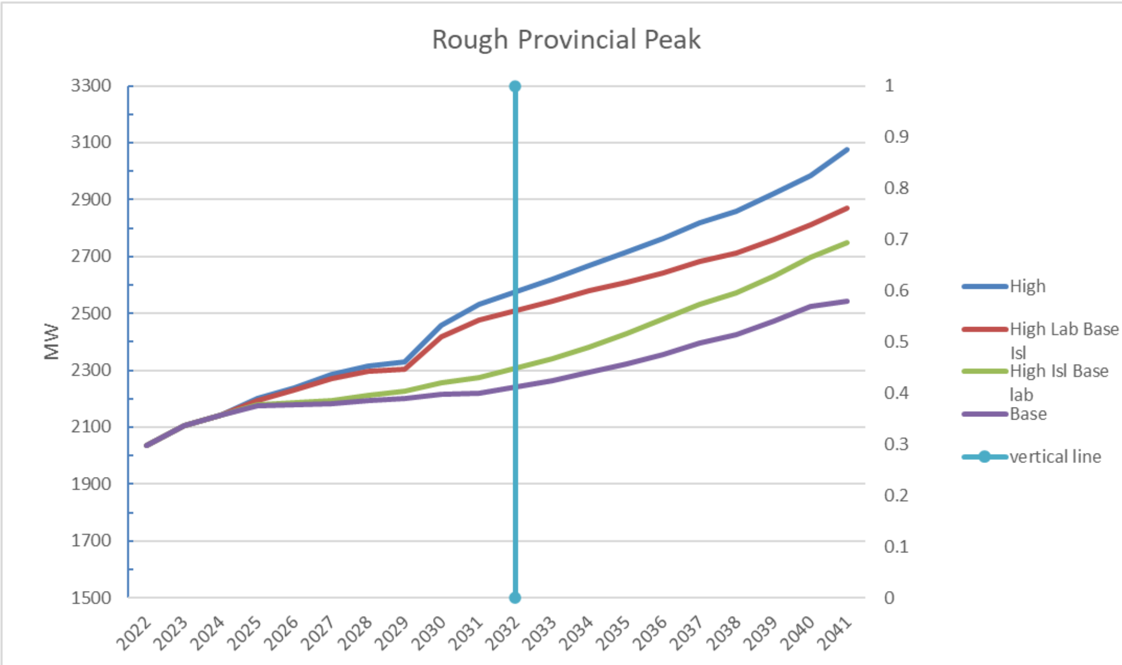
- Hydro's energy forecast methodology aligns with industry standards for residential and business forecasting through their reliance on regression analysis with consideration of economic growth and price and income elasticity; and a probabilistic assessment of demand requirements is completed producing P50 and P90 projections incorporating weather extremes. Hydro's analysis is sound and reflects the state of the industry for developing long term projections. However, as is the case in the industry today, there remains significant uncertainty with respect to provincial policies particularly with regard to electrification, adoption of EVs and the speed at which all of these will occur. Adding to the uncertainty is economic growth associated with provincial policies for attraction of new industries – an extremely difficult aspect to project with certainty.

- Weather extremes have been analyzed and Hydro is relying on their work and Daymark's independent analysis of weather implications initially completed for peak demand in 2018. Hydro simplifies the process by using a point estimate of the magnitude of difference based on the historic probabilistic assessment. Periodic analysis of the probabilistic results should be part of Hydro's plan since weather extremes appear to be happening frequently and with greater variation. The current analysis using the confirmed point estimate is acceptable.
- Industrial load forecasts rely on specific customer information about their plans which are typically not certain but due to the size and diversity of the industrial base in the province are the best information available to develop the reference or base case forecast for both energy and peak. New customer loads are very uncertain as thousands of MW's of attachment requests are in hand but Hydro's resources and delivery system may not be able to add such an increase without new infrastructure and resource investment. Both existing and new customer loads currently rely on "interruptible" rates ensuring that such loads are not impacting Hydro's peak periods when resources may be tight, this policy of interrupting load can impact economic growth in the province or result in such customers seeking alternative solutions. This load potential results in significant forecasting uncertainties, however, Hydro is assessing the needs by incorporating their presence into system planning to understand the investment and economic implications.

Planning approach

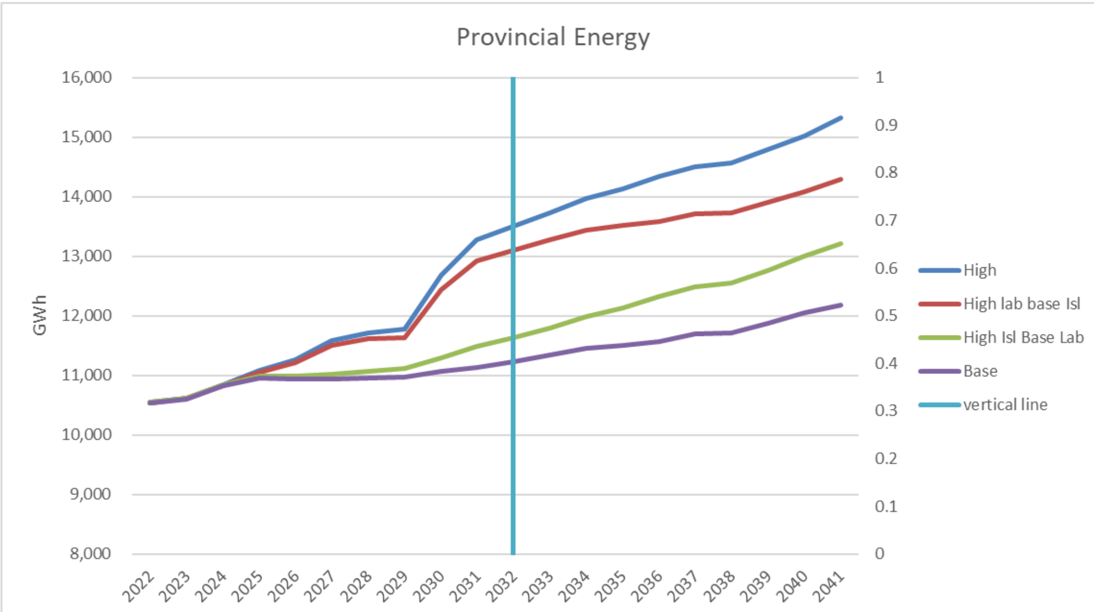
- Many cases were developed for the Island Interconnected System and the Labrador Interconnected Systems and the potential new industrial loads. To assess reliability and identify resource need a range of futures should be evaluated to understand the uncertainty impacts and risks to reliability that result. Hydro relies upon four key cases to perform the analysis including a range of assumptions for the key uncertainties in order to evaluate the implications on investment and decision timing. Figures 1 and 2 below demonstrate the four cases and the breadth of the need that result for both energy and demand in the province.
- The projected NL peak demand ranges from 1,983 MW today to a range of values in the year 2032 between 2,241 MW to 2,577 MW and in the year 2041 between 2,543 and 3,075 MW.

Figure 1 NL Peak Projections – 4 Futures



- Energy needs are depicted in Figure 2 for the Province showing the varying levels of potential for growth as well.

Figure 2 Energy forecast ranges

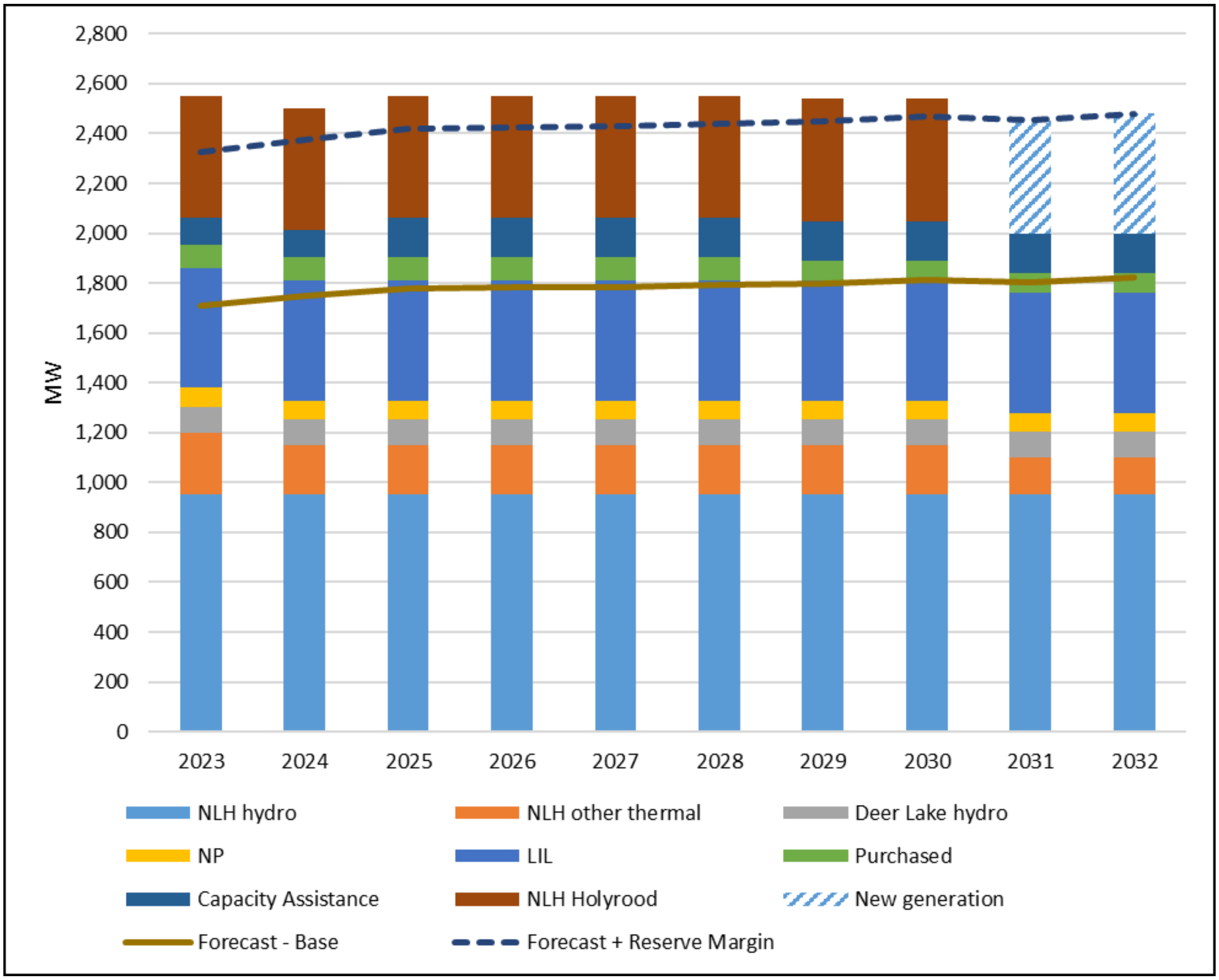


Observations and Planning Evolution Implications

- Hydro's forecast, as noted earlier, incorporates projections of the implications of electrification and adoption of EVs in the province. The EV projections provided by a consultant developed forecasted adoption rates and electric demand impacts using model availability, jurisdiction-specific barriers and constraints, income levels, and total cost of ownership as key inputs into their model. An aggressive policy adopted by the province relative to EVs in conjunction with more favorable EV market conditions as presented in the forecast scenarios could result in faster and increased adoption rates that may exceed the projections incorporated in the values shown in Figures 1 and 2. Similarly, the electrification estimates incorporated in the current forecast may again be exceeded, since the majority of the included electrification is focused on government buildings. Should the province adopt a more aggressive and supportive electrification policy, the current projections do not reflect that situation and may be conservative.

- An additional consideration for Hydro is the need, as discussed in the resource planning and R&RA analyses, for locational resource planning – that is each region of NL must plan assuming there will be no support from outside its current infrastructure. Since the Island System is independent of the mainland, resources must be available on island to serve that load during conditions that result in isolation. The energy and demand forecasts are developed independently and summed (as shown in the Figures above) and Hydro's planning addresses the locational need for infrastructure investment. Figure 3 below depicts the base peak demand scenario for the Island System only in comparison to resources available in isolation to serve that load. This Figure and the discussion of uncertainty here gives rise to short-term urgency of the potential need for resources particularly if the adoption of EVs and electrification and new loads occur at a greater level than is incorporated in the projections.

Figure 3 Comparison of Forecast Peak Demand and Firm Capacity Resources for the Island System[1]



[1] This figure includes a reserve margin of 36%, assumes that the LIL is available at 675 MW with a bipole FOR of 5%, and includes losses in the firm capacity.

- Hydro's forecasting is sound and incorporates the ability to analyze multiple potential futures, while addressing the many uncertainties in the industry; Hydro's multiple future options supports the evaluation of R&RA as the local economy and industry changes move ahead.

- Although we conclude that the methodologies used by Hydro are consistent with industry practice, the frequency of service requests by potential industrial customers and urgency of potential load growth implications being considered should continue to be further assessed as this report is under review. Hydro has initiated investigations into renewable energy resources and is working with the government to better understand the potential for adoption of electrification policies. Planning is a continuous effort as is fully demonstrated at this moment in time when change is becoming a standard in the industry. Hydro should continue to make resource decisions that can be modified or can move aggressively to address need. The pending analysis of renewable energy options will likely provide additional insights relative to the ability of Hydro to plan for alternative futures effectively.

Volume III, Attachment 4

Reliability Analysis of the
Holyrood Thermal Generating Station
For Backup or Standby Operation

newfoundland labrador hydro

Reliability Analysis of Holyrood Thermal Generating Station For Backup or Standby Operation

newfoundland labrador hydro

Contents

1.0 Overview

Historically, Forced Outage Rates ("FOR") for the three units at the Holyrood Thermal Generating Station ("Holyrood TGS") have been reported using the Derated Adjusted Forced Outage Rate ("DAFOR") metric, which is predominately used for units that operate in a continuous (base load) capacity.

The Holyrood TGS has been historically operated as a base load generation facility, with all three units generating during the winter operating season. In addition to operation as a generation, Unit 3 has also operated as a synchronous condenser during the summer months.

When considering standby or peaking operations of units at the Holyrood TGS, DAFOR is no longer the most appropriate measure of FOR. Common standby metrics include Utilization Forced Outage Probability ("UFOP") and Derated Adjusted Utilization Forced Outage Probability ("DAUFOP"), which are currently used for Newfoundland and Labrador Hydro's gas turbine fleet.

When considering standby or peaking operations of units at the Holyrood TGS, DAUFOP is a more appropriate measure given the frequency of deratings historically experienced by these units. The operational data, which is used as input data produce the DAFOR measure, can also be used to establish a historical record of the performance of these assets when considering operations in a standby or peaking capacity.

All operational data for the period of January 1, 1993[1] to May 1, 2022 was collected and two different methods of analysis were used to assess appropriate FOR and a third analysis was completing to assess starting reliability of the units at the Holyrood TGS.

A brief overview of the methodology used in each analysis as well as the results are provided below.

1.1 Using Historical Data to Calculate DAUFOP instead of DAFOR (January 1 to December 31)

Chart 1 to Chart 3 provides historical annual DAUFOP outcomes for each unit for the period of January 1 to December 31 of each of the year from 1993 to 2021.

[1] Accurate operational data for Holyrood TGS is not available for the period prior to January 1, 1993.

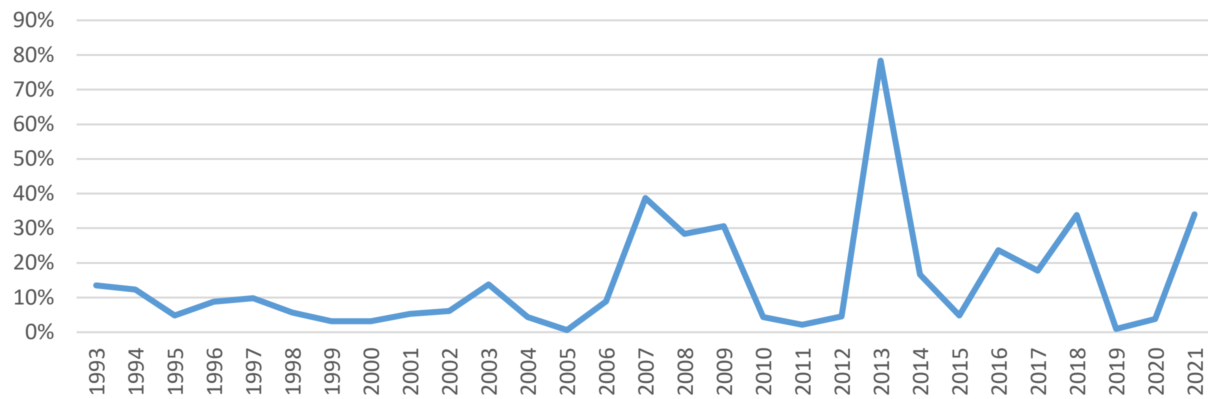


Chart 1: Holyrood Unit 1 DAUFOP Performance (January 1 to December 31)

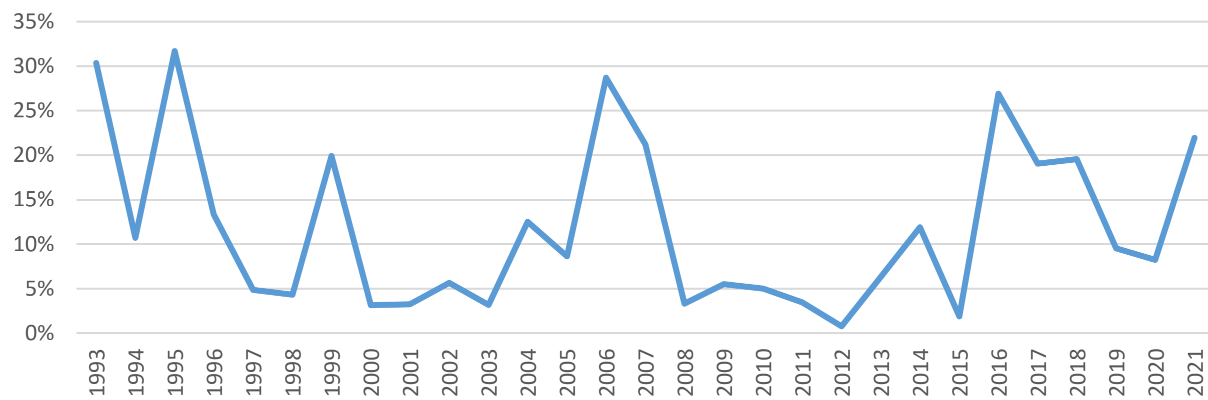


Chart 2: Holyrood Unit 2 DAUFOP Performance (January 1 to December 31)

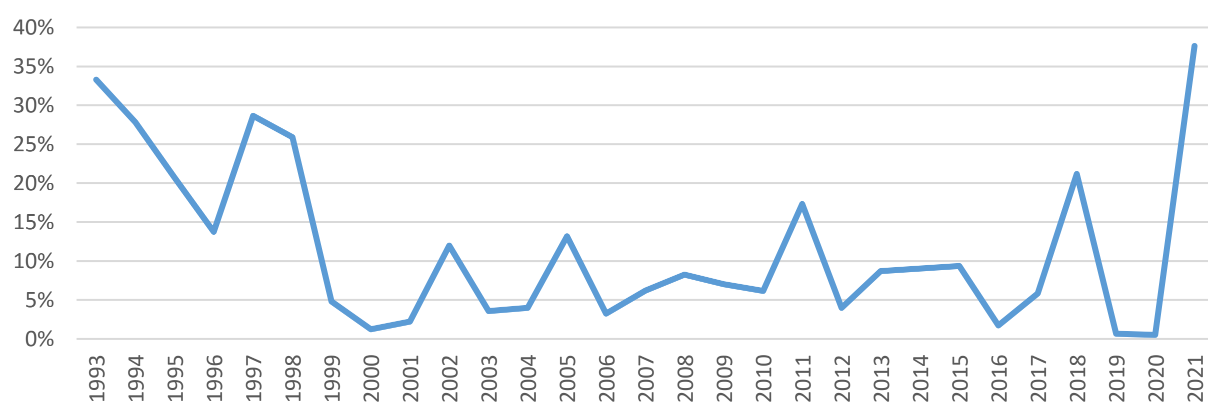


Chart 3: Holyrood Unit 3 DAUFOP Performance (January 1 to December 31)

The overall average, five-year average, and ten-year average for each unit for the period between January 1 and December 31 is summarized in Table 1.

Table 1: Average DAUFOP Performance (January 1 to December 31)

Unit	Overall Average (1993–2021)	Five-Year Average (2017–2021)	Ten-Year Average (2012–2021)
Holyrood Unit 1	14.6%	18.0%	21.8%
Holyrood Unit 2	11.9%	15.7%	12.6%
Holyrood Unit 3	11.7%	13.2%	9.9%
Total Holyrood Plant	12.7%	15.6%	14.8%

The analysis resulted in a ten-year average DAUFOP for the Holyrood Plant of 14.8%.

1.2 Using Historical Data to Calculate DAUFOP instead of DAFOR (April 1 to November 1)

Similar to the above analysis, the historical operating data from 2012 to 2021 was used to calculate DAUFOP performance; however, this time only the period of April 1 to November 1 of each year was considered. The purpose was to remove the bulk of the operating hours to better resemble what operations would look like in a standby operating scenario versus how Holyrood normally operates during the winter months as base load.

Chart 4 to Chart 6 provides the annual DAUFOP outcomes for each unit for the period of April 1 to November 1 of each of the year from 2012 to 2021.

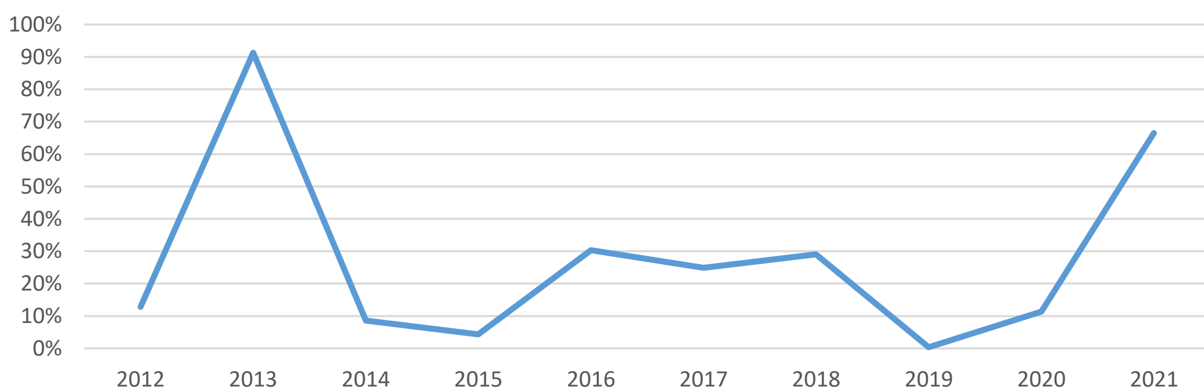


Chart 4: Holyrood Unit 1 DAUFOP Performance (April 1 to November 1)

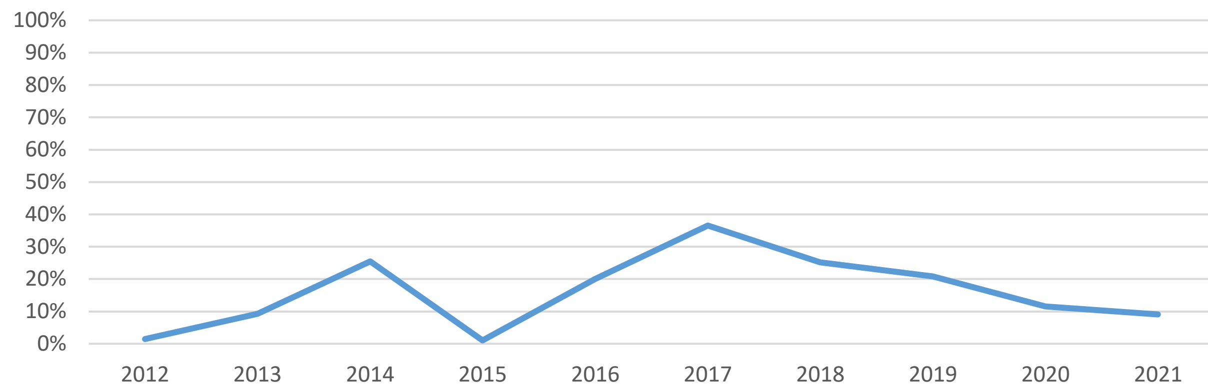


Chart 5: Holyrood Unit 2 DAUFOP Performance (April 1 to November 1)

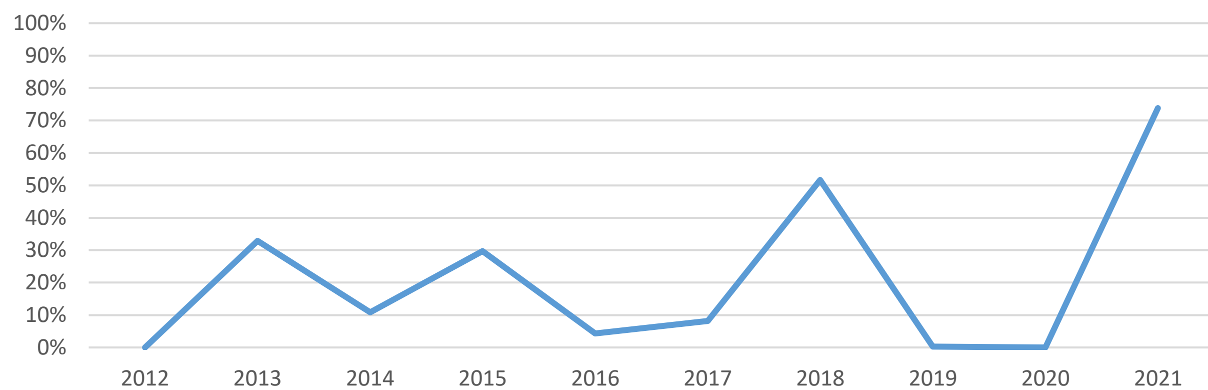


Chart 6: Holyrood Unit 3 DAUFOP Performance (April 1 to November 1)

1 The five-year and ten-year average for each unit for the period between April 1 and November 1 is
2 summarized in Table 2.

Table 2: Average DAUFOP Performance (April 1 to November 1)

Unit	Five-Year Average (2017–2021)	Ten-Year Average (2012–2021)
Holyrood Unit 1	26.4%	27.9%
Holyrood Unit 2	20.6%	16.0%
Holyrood Unit 3	26.8%	21.2%
Total Holyrood Plant	24.6%	21.7%

3 The analysis resulted in a ten-year average DAUFOP for the Holyrood Plant of 21.7%. This is believed to be
4 a more accurate reflection of FOR if the Holyrood Units move to a standby/peaking operating scenario.

1.3 Starting Performance and Outcomes when Considering a Required Minimum Six-Week Run-Time

To better understand the starting performance of the units at Holyrood TGS, the operational data from January 1, 1993 to May 1, 2022 was reviewed and each attempted start was identified as well as its outcome when considering a required minimum run-time of six weeks of operation.

Starts were categorized one of four ways:

1) As starting failure where the unit did not synchronize to system;
2) Starts that resulted in a trip within six weeks;
3) Starting in a derated[2] condition or that resulted in a derating within six weeks; and
4) Starts that resulted in full-load operation until a scheduled stop or for at least six weeks.

Historical starting failure data for all three units at the Holyrood TGS was reviewed. Restoration times following the failed starts range from hours to upwards of 12 days; however, the average restoration time is approximately 3 days.

It was determined that successful starts and starts in a derated condition or that resulted in a derating be combined to provide a percentage of time the unit was capable of supplying any generation to the provincial electricity system. The outcome of this analysis for each unit for all data available as well as for the ten years from January 1, 2012 to May 1, 2022 is provided in Table 3,

Table 4, and Table 5.

Table 3: Start Summary of Unit 1

Start Category	January 1, 1993 to May 1, 2002	January 1, 2012 to May 1 2022
Failed Starts	29 (8.2%)	11 (8.8%)
Starts Resulting in Trip	104 (29.4%)	53 (42.4%)
Successful Starts and Starts with Derates	221 (62.4%)	61 (48.8%)
Total Starts	**354**	**125**

[2] A derating is defined by Electricity Canada (formerly the CEA) as a capacity reduction >2% of the Unit's Maximum Continuous Rating. Historical data for the Units at Holyrood TGS shows the units have operated in a derated state for approximately 27% of their operating time with an average derated capacity of 110 MW.

Table 4: Start Summary of Unit 2

Start Category	January 1, 1993 to May 1, 2002	January 1, 2012 to May 1, 2022
Failed Starts	18 (45.0%)	10 (6.9%)
Starts Resulting in Trip	149 (40.9%)	62 (43.1%)
Successful Starts and Starts with Derates	197 (54.10%)	72 (50.0%)
Total Starts	**364**	**144**

Table 5: Start Summary of Unit 3

Start Category	January 1, 1993 to May 1, 2002	January 1, 2012 to May 1, 2022
Failed Starts	15 (5.1%)	6 (6.5%)
Starts Resulting in Trip	125 (42.8%)	35 (38.0%)
Successful Starts and Starts with Derates	152 (52.1%)	51 (55.4%)
Total Starts	**292**	**92**

2.0 Analysis and Recommendations

The analysis considers Holyrood TGS performance based on historical records, analysis of appropriate levels of performance for consideration of the viability and suitability of the Holyrood TGS to be used as a backup generating facility to the Labrador-Island Link in consideration of the significant reduction in operating hours each unit is forecast to receive while operating in a standby capacity. Additionally, the most likely operational status of each unit as presented for a standby scenario was considered, with Holyrood Units 1 and 2 normally in a standby state and Holyrood Unit 3 operating as a synchronous condenser.

Also worth noting is the question surrounding the suitability of the Holyrood TGS to perform as a standby generation facility? Although Units 1 and 2 may be available and capable of starting in some period of time to support after an unplanned outage, normally in the range of 24 hours, with Unit 3 requiring an additional 24 hours to convert the unit from synchronous condenser to generation mode;

consideration should be given to its lack of proven reliable starting as well as historical success rate in short duration run scenarios as assessed in Section 1.3.[3]

With the above considerations noted, when considering future operations of the Holyrood TGS as a backup generating facility, it is recommended to use DAUFOP values in the ~20% range, as provided in the April 1 to November 1 data analysis completed in Section 1.2. Additionally, as projected operation becomes better understood, appropriate sensitivity numbers should be selected to ensure a wide range of potential performance outcomes are considered.

[3] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd., March 30, 2022 filed as Attachment 3 to the "Reliability and Resource Adequacy Study Review – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station, Newfoundland and Labrador Hydro, March 31, 2022.

Volume III, Attachment 5

Full Results of Energy Criteria Analysis

Full Results of Energy Criteria Analysis

The Newfoundland and Labrador Interconnected System energy criteria is such that the Newfoundland and Labrador Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.[1]

Table 1 outlines the Island and Labrador forecast load cases[2] against the year in the study period that energy requirements are identified. These forecasts are discussed in detail in Volume III, Section 4, of the 2022 Update.

Table 1: Forecasts versus Firm Energy Criteria

Island and Labrador Load Scenario	Year of Energy Requirements
Base Island/Base Labrador	-
Base Island/High Labrador	2031
High Island/Base Labrador	-
High Island/High Labrador	2030

The Newfoundland and Labrador Interconnected System does not violate the energy criteria in the Base Island/Base Labrador scenario or the High Island/Base Labrador scenario. However, it does violate the energy criteria in the Base Island/High Labrador scenario by 2031 and in the High Island/High Labrador scenario by 2030. Refer to Table 4 for a detailed comparison.

The analysis assumes that the contracts with the Corner Brook Co-Generation, and Rattle Brook hydro-electric project expired, the St. Lawrence and Fermeuse wind projects end in 2029, and the Holyrood Thermal Generation Station ("Holyrood TGS") retires in 2030. As well, it is assumed that required energy can be transferred from Labrador to the Island via the Labrador-Island Link. However, the timing of these retirements do no affect the timing for the requirement of additional firm energy.

[1] On the Island, firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood TGS) is based on energy capability adjusted for maintenance and forced outages.
[2] The forecast values include bulk transmission system losses.

Table 2: **Existing Interconnected Island System Firm Energy Capability**[3]

Generation Assets	Firm (GWh)
Hydraulic Generating Units	
Bay d'Espoir	2,096
Upper Salmon	317
Hinds Lake	290
Cat Arm	678
Granite Canal	188
Paradise River	33
Mini Hydro	-
Total Hydraulic Generation	**3,602**
Thermal Generating Units	
Holyrood TGS	2,996
Hardwoods GT	-
Stephenville GT	-
Holyrood GT	-
Diesels:	
Hawke's Bay and St. Anthony Diesel	-
Total Thermal Generation	**2,996**
Other Island Generation Sources	
Newfoundland Power (Hydro)	324
Newfoundland Power (Thermal)	0
Total Newfoundland Power Owned	**324**
Total Deer Lake Power Owned	**793**
Power Purchase Agreements	
Exploits Grand Falls and Bishop's Falls	547
Star Lake	87
Corner Brook Cogen	-
Rattle Brook	-
St. Lawrence Wind	92
Fermeuse Wind	75
Total Power Purchases	**801**
Muskrat Falls at Soldier's Pond	**3,317**
Imports	**-**
Total Island Interconnected System	**11,833**

[3] As of January 2023.

Table 3: Labrador Interconnected System Firm Energy Capability[4]

	Firm (GWh)
Recapture Block	2,362
TwinCo Block	1,971
Happy Valley GT	-
Total Labrador Interconnected System	**4,333**

Table 4: Installed Firm Energy versus Forecast (GWh)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Installed Firm Energy - Island	11,833	11,833	11,833	11,833	11,833	11,833	11,666	8,670	8,670	8,670
Installed Firm Energy - Labrador	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333
Total	**16,166**	**16,166**	**16,166**	**16,166**	**16,166**	**16,166**	**15,999**	**13,003**	**13,003**	**13,003**
Forecast Annual Energy Required										
Base Island	8,089	8,302	8,444	8,410	8,407	8,427	8,439	8,529	8,603	8,691
Base Labrador	2,952	2,958	2,963	2,967	2,970	2,972	2,977	2,982	2,987	2,993
Total	**11,040**	**11,260**	**11,407**	**11,376**	**11,378**	**11,399**	**11,416**	**11,510**	**11,590**	**11,683**
Firm Energy - Surplus (Deficit)	5,126	4,906	4,759	4,790	4,788	4,767	4,583	1,493	1,413	1,320
Forecast Annual Energy Required										
Base Island	8,089	8,302	8,444	8,410	8,407	8,427	8,439	8,529	8,603	8,691
High Labrador	2,952	2,969	3,060	3,264	3,571	3,668	3,681	4,450	4,877	4,984
Total	**11,040**	**11,271**	**11,504**	**11,674**	**11,978**	**12,095**	**12,121**	**12,979**	**13,480**	**13,674**
Firm Energy - Surplus (Deficit)	5,126	4,895	4,662	4,492	4,188	4,071	3,878	24	(477)	(671)
Forecast Annual Energy Required										
High Island	8,098	8,318	8,476	8,464	8,492	8,540	8,582	8,766	8,970	9,103
Base Labrador	2,952	2,958	2,963	2,967	2,970	2,972	2,977	2,982	2,987	2,993
Total	**11,050**	**11,276**	**11,439**	**11,431**	**11,463**	**11,512**	**11,558**	**11,747**	**11,956**	**12,096**
Firm Energy - Surplus (Deficit)	5,116	4,890	4,727	4,735	4,703	4,654	4,441	1,256	1,047	907
Forecast Annual Energy Required										
High Island	8,098	8,318	8,476	8,464	8,492	8,540	8,582	8,766	8,970	9,103
High Labrador	2,952	2,969	3,060	3,264	3,571	3,668	3,681	4,450	4,877	4,984
Total	11,050	11,287	11,536	11,728	12,063	12,208	12,263	13,215	13,847	14,087
Firm Energy - Surplus (Deficit)	5,116	4,879	4,630	4,438	4,103	3,958	3,736	(212)	(844)	(1,084)

[4] As of January 2023.

Volume III, Attachment 6

Bay d'Espoir Hydroelectric Generating Facility

Unit 8 Summary Report

Bay d'Espoir Hydro Generating Unit 8
Summary Report

newfoundland labrador hydro

Executive Summary

The study includes the consideration of the development of a 154 MW unit (Unit 8) located in Powerhouse 2 next to existing Unit 7 at a total capital cost of $522.0 million (approximately $3.4 million per megawatt).

The principal parameters for this development are as follows:

• Time to project in-service	70 months
• Installed Capacity	154 MW
• Number of Units	1
• Estimated Unit Efficiency	98%

The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned. As this project would share the existing annual water supply from the existing watershed, there is no direct increased energy production associated with this project.

The Bay d'Espoir Unit 8 would interconnect to the Island transmission system via construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to Terminal Station No. 2 ("TS2").

Operations and Maintenance ("O&M") is estimated to have costs of 1% to 2% of direct project costs per year.

Contents

1.0 Project Description

Bay d'Espoir Unit 8 is a proposed 154 MW unit located in Powerhouse 2 next to the existing Unit 7. The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned.

The Bay d'Espoir facility is comprised of a reservoir including dams and a spillway; two adjacent powerhouses with an average gross head of 179 metres and a total installed capacity of 600 MW; and a tailrace channel rejoining the Bay d'Espoir facility. The addition of Unit 8 would be comprised of the following key components:

- An enlarged headrace channel, including a bifurcation excavated in the rock, supplying both the existing entrance channel to Unit 7 intake and the new entrance channel to Unit 8 intake;
- A new water intake similar to the existing intakes;
- A new buried steel penstock connecting the new intake to the new generating unit;
- A new generating unit; and
- An additional service bay as part of Powerhouse 2 next to existing Unit 7.

The electricity would be produced by the use of a Francis-type turbine, with a rated output of 154 MW.

To complete the interconnection with the existing system, Bay d'Espoir Unit 8 would interconnect to the system via the construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to TS2.

2.0 Generation Characteristics

The principal parameters for this development are as follows:

• Installed Capacity	154 MW at generator terminals
• Rated Flow	102 m^3/s
• Gross Head Design	179.75 m
• Net Design Head	173.5 m
• Rotating Speed	near 225 rpm
• Estimated Generator Efficiency	98%

3.0 Transmission Requirements

Bay d'Espoir Unit 8 would interconnect to the system via construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to TS2. The line route would be parallel to the existing line between Unit 7 and TS2 with five transmission line crossings and one river crossing.

4.0 Environmental Considerations

Hydroelectric developments of this nature will be subject to the provincial *Environmental Protection Act*, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an environmental preview report or an environmental impact statement be required. The project could also be subject to the federal Environmental Assessment Process. The federal government, in accordance with the *Canadian Environmental Assessment Act,* usually reviews undertakings that are subject to the provincial Environmental Assessment Process. Where possible the provincial and federal Environmental Assessment Process are harmonized in an effective and timely manner.

The most substantial environmental impact is anticipated to be during the construction phase of the project. However, as the expanded hydropower facility will be integrated to the existing facilities operation with limited changes to the actual operations, less environmental impacts are expected compared to a new hydropower facility.

Similar to the hydroelectric component, transmission line construction would also be subject to environmental assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of runoff from spoil areas and the relocation of fish during dewatering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the project. An Environmental Protection Plan generally outlines the owner's policy with respect to environmental protection, the owner's responsibility, the contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5.0 Cost

5.1 Methodology

The cost estimate for the construction of Bay d'Espoir Unit 8 is an AACE[1] Class 3 estimate, completed by SNC Lavalin in 2017, escalated to 2022 costs. Typical accuracy ranges for the AACE Class 3 estimates are -10% to -20% on the low side and +10% to +30% on the high side. These accuracy ranges depend on the technological complexity of the project and level of engineering achieved.

All sales taxes have been excluded from the estimate as they are refundable.

5.2 O&M Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

[1] American Association of Cost Engineering ("AACE").

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

It is expected that there is no material incremental variable O&M cost associated with Unit 8 as the variable cost for the Bay d'Espoir facility is not expected to increase as a result of an additional unit. As mentioned previously, there is no direct increased energy production associated with this project.

6.0 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The schedule assumes an overall project duration of 70 months, with construction lasting 54 months. Estimated project duration has increased since 2017 for several reasons:

i. Increased time to prepare the project for approval including updating class 3 estimates for cost and schedule once field work is completed;

ii. Extended time frame to procure long lead time items (i.e., on the critical path is the time to acquire the generator); and

iii. Longer management contingency of six months.

A summary of the schedule is as follows:

6.1 Year One

- Cost and Schedule upgade;
- Environmental and Regulatory approval process initiated; and
- Complete additional field testing.

6.2 Year Two

- Completion of environmental and regulatory approvals;
- Engineering detailed design; and
- Prepare tender documents and award contracts.

6.3 Year Three

- Continued engineering/procurement of major equipment;
- Upgrade access road to Unit 7;
- Excavate laydown areas;
- Construction of camp facilities;
- Installation of site services infrastructure;
- Start powerhouse concreting;
- Start penstock construction;
- Approach channel excavation;
- Powerhouse mechanical and electrical;
- Tailrace excavation; and
- Construct the switchyard.

6.4 Year Four

- Completion of powerhouse mechanical and electrical;
- Construct the intake;
- Complete construction of powerhouse;
- Start powerhouse mechanical and electrical;
- Trashracks assembly and installation; and
- Rock plug excavation.

6.5 Year Five

- Complete powerhouse mechanical and electrical;
- Start turbine installation; and
- Construct the transmission line.

6.6 Year Six

- Install the turbine;
- Final testing and commissioning; and
- Complete site rehabilitation works.

The following works/activities are considered to be on the critical path of the project:

- Water to Wire ("W2W") Equipment Packages are long-lead items and larger size turbine generator unit design, manufacturing, and installation timeline will likely form the critical path;
- Post-pandemic global supply chain challenges;
- Labour shortages which will be aggravated by a renewal energy project boom; and
- Environmental and regulatory approvals.

7.0 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project. Minimal impact to the existing system is anticipated during construction and any identified environmental concerns can be addressed through the implementation of mitigation measures. However, as construction will be occurring on a brownfield site, no additional environmental issues are expected.

Additionally, Powerhouse 2 was commissioned in 1977 (Phase 3) and the addition of a future unit was considered during construction. As such, rock excavation for the second unit was completed, and the downstream portion of the draft tube, complete with the draft tube gates guides were constructed to minimize interfering with the operation of the existing Unit 7 during the addition of Unit 8.

Volume III, Attachment 7

Final Report – Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8

newfoundland labrador hydro

Newfoundland and Labrador Hydro

Final Report

For

Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8

H363582-00000-228-230-0001
Rev. 0
December 11, 2020

Newfoundland and Labrador Hydro

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HATCH

Newfoundland and Labrador Hydro
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Hydroelectric Generating Unit No. 8
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NEWFOUNDLAND & LABRADOR

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Table of Contents

List of Appendices

Appendix A: Hydrological Analysis
Appendix B: Hydro Reference Inflow Series

List of Tables

List of Figures

Executive Summary

In August 2020, Newfoundland and Labrador Hydro (Hydro) engaged Hatch Ltd. (Hatch) to complete a hydrology and feasibility study for a potential new generating unit (Unit 8) at the Bay d'Espoir Hydroelectric Generating Station. This report documents the scope of work, background information, methodology, results, conclusions and recommendations of the study.

The Bay d'Espoir Hydroelectric System is located in south-central Newfoundland. There are three generating plants in the system: Granite Canal Hydroelectric Generating Station, Upper Salmon Hydroelectric Generating Station, and Bay d'Espoir Hydroelectric Generating Station. These plants have a combined total of 737.4 MW of installed capacity and account for almost 40 percent of the Island of Newfoundland's electricity needs. The Bay d'Espoir Hydroelectric Generating Station has six units housed in Powerhouse No. 1 and one unit (Unit 7) in Powerhouse No. 2. Hydro is reviewing the installation of an additional 154.4 MW unit (Unit 8) at Bay d'Espoir Powerhouse No. 2 next to the existing Unit 7. When Unit 7 was constructed in 1977, provision was made for a future Unit 8 by undertaking limited civil works.

The objective of the study was to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system. The scope of work included background data review; hydrological analysis; power and energy model (Hatch Vista DSS) analysis; and identification of any required environmental studies.

The hydrological analysis concluded that, for the purpose of this study, the Hydro inflow series may be used as provided, for the power and energy analysis of the proposed new Unit 8.

The power and energy analysis concluded that addition of Unit 8 to the Bay d'Espoir plant does not impact the firm energy of the Bay d'Espoir system.

The simulated average annual energy of the Bay d'Espoir system is 3,394.11 GWh. The simulated average annual energy of the system with addition of Unit 8 to the Bay d'Espoir plant is 3,416.74 GWh, a 0.67 percent increase. The simulated average annual energy of the Bay d'Espoir plant is 2,617.65 GWh. The simulated average annual energy of the plant with addition of Unit 8 is 2,650.64 GWh, an increase of 1.2 percent.

With addition of Unit 8, simulated hourly generation of the Bay d'Espoir plant increases 17.6 percent of the time and decreases 29.7 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.

The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 140.7 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because, although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in

simulated on-peak generation is at the expense of simulated off-peak generation. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.

With addition of Unit 8, simulated Bay d’Espoir plant efficiency increases are in the range of 0.0016 to 0.0125 percent, with an average of 0.008 percent.

The North Salmon bypass spillway is used only 0.6 percent of the time in the simulation of the existing system, and 1.1 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d’Espoir Unit 8. This loss occurred only 2.3 percent of the time.

Hatch has not examined the impact of water surface drawdown on the adequacy of submergence of power intakes as part of this study, as this is a hydraulic phenomenon that cannot be analyzed explicitly in a water management model such as Vista. It is recommended that this issue be examined in a separate hydraulic study. The tailrace channel improvement described by SLI (2018b) should be implemented in order to avoid generation loss when all units at the expanded Bay d’Espoir plant are running. Otherwise, the information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d’Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.

The following end-of-November elevation ranges are recommended at the large storage reservoirs in the system to optimize Bay d’Espoir system generation in the winter months while allowing room for possible early winter high flow.

- Victoria: 324.18 m to 325.44 m
- Meelpaeg: 271.46 m to 272.11 m
- Long Pond: 181.70 m to 182.25 m.

If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter. Hydro should consider further study to examine the impact that lower reservoir levels in advance of winter may have upon generation.

1. Introduction

In August 2020, Newfoundland and Labrador Hydro (Hydro) engaged Hatch Ltd. (Hatch) to complete a hydrology and feasibility study for a potential new generating unit at the Bay d'Espoir Hydroelectric Generating Station. This report documents the scope of work, background information, methodology, results, conclusions and recommendations of the study.

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The Bay d'Espoir Hydroelectric Generating Station has six units housed in Powerhouse No. 1 and one unit (Unit 7) in Powerhouse No. 2. Hydro is reviewing the installation of an additional 154.4 MW unit (Unit 8) at Bay d'Espoir Powerhouse No. 2 next to the existing Unit 7. When Unit 7 was constructed in 1977, provision was made for a future Unit 8 by undertaking limited civil works.

1.1 Objective

The objective of the study is to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system.

1.2 Scope of Work

The scope of work includes the following components.

- Background data review.
- Hydrological analysis for the Bay d'Espoir system, which includes the Victoria, Burnt, Granite, Meelpaeg, Upper Salmon and Long Pond Reservoirs, including verification against external sources, where available. A detailed hydrological analysis from 1970 to present is required with a limited review of the full hydrological record.
- Power and energy model (Hatch Vista DSS) analysis with consideration of the following issues:
  - Potential operating procedure modifications, following the addition of Unit 8
  - Average annual energy of the Bay d'Espoir Hydroelectric Generating Station
  - Firm annual energy of the Bay d'Espoir Hydroelectric Generating Station
  - Average monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station

- Firm monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station
- Impact on the operation of Upper Salmon Hydroelectric Generating Station
- Operations to control frazil ice at the generating stations in the system
- Target storage of the Bay d'Espoir system reservoirs in advance of the winter operating season
- Impact on efficiency for Bay d'Espoir Hydroelectric Generating Station
- Inclusion of fish compensation requirements at Granite Canal Hydroelectric Generating Station and fisheries releases at Pudops Dam for Grey River and Burnt Spillway for White Bear River
- Any other operational constraints or inadequacies that may be identified during the study.

* Identification of any required environmental studies.
* Technical report.

2. Background Data Review

2.1 System Description

The Bay d'Espoir system is located in south-central Newfoundland, as shown in Figure 2-1. Figure 2-2 shows the general arrangement of the drainage basin, with the locations of each of the major structures noted as well. The characteristics of the reservoirs in the system are summarized in Table 2-1 (Hydro, 2015). All elevations in this report are related to Canadian Geodetic Vertical Datum 1928 (CGVD28) except where otherwise noted.

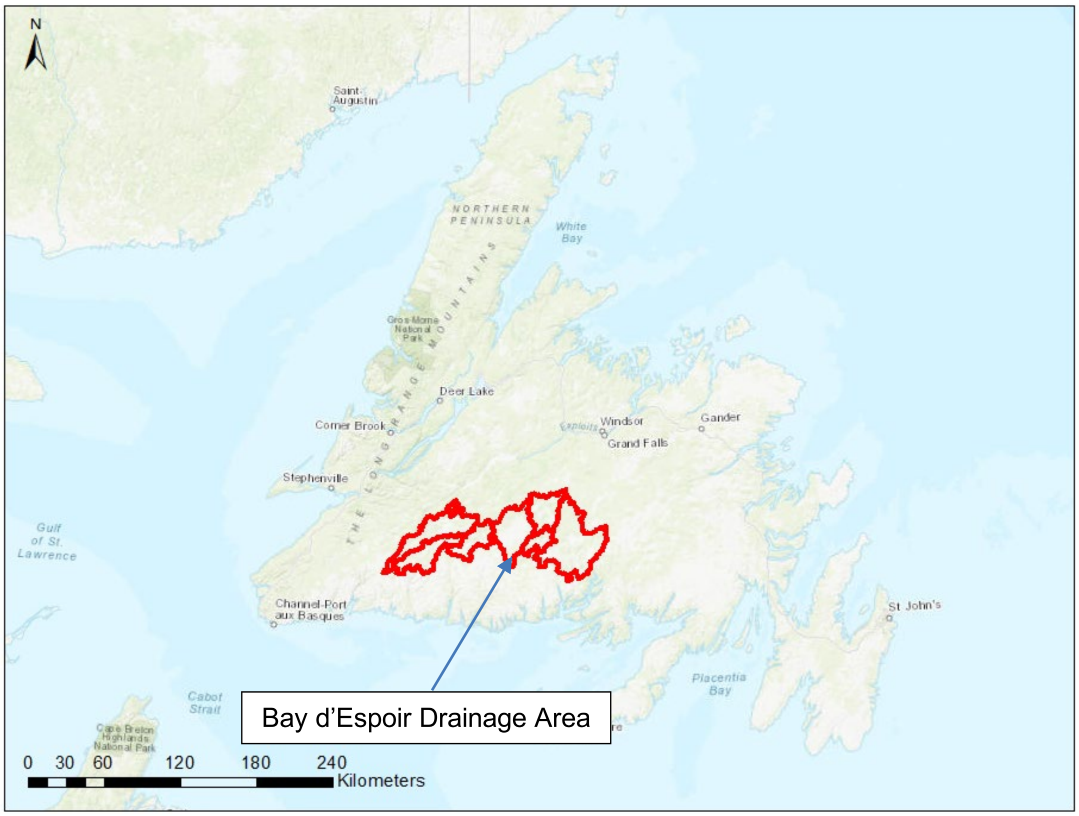

Figure 2-1: Location Map

The system includes Victoria Lake, Burnt Pond, Granite Lake, Meelpaeg Reservoir, Great Burnt Lake, Upper Salmon Reservoir, and Long Pond. (For clarity, the Upper Salmon Reservoir is formed by Great Burnt Lake and Cold Spring Pond, which are connected by a diversion canal.) The headwaters of the Bay d'Espoir system begin at Victoria Lake at an approximate elevation of 320 m. Through a constructed array of dams and canals, water is directed across several diverted watersheds to generating plants at Granite Canal, Upper Salmon and finally to Bay d'Espoir where it is discharged to tidewater at the Atlantic Ocean.

The system has a total live storage of more than 3,660 million m^3 of water and a total drainage area of 5,903 km^2.

The reservoirs in the Bay d'Espoir system provide about 75 percent of the hydraulically derived electrical energy produced by Hydro on the Island of Newfoundland and are managed in concert with the corporation's other hydraulic resources. Maximum storage levels at these reservoirs are a function of spill elevation, with provisions for sudden seasonal inflow, while minimum levels at these reservoirs are associated with maintaining adequate head for generator operation. In addition, maximum operating levels are a function of dam stability and freeboard requirements as well as being able to pass the inflow design flood (IDF). Minimum levels are associated with minimum head but also erosion protection level on constructed dams.

Currently, the releases from the Bay d'Espoir reservoirs are achieved by scheduled gate openings at Victoria Control Structure, scheduled production at Granite Canal, scheduled production at Upper Salmon Generating Station with appropriate releases at Ebbegunbaeg Control Structure and scheduled thermal plant production at Holyrood in association with other hydraulic production on the system. Typically, Hydro operates the Granite Canal and Upper Salmon Generating Stations at their most efficient settings, while operating the Bay d'Espoir Generating Station to meet the balance of the overall load on the Bay d'Espoir system.

Hydro has the ability to pass excess flows out of the basin through spillways on Victoria Lake, Burnt Pond, Granite Lake, and Long Pond. There are also spillways on Great Burnt Lake and Cold Spring Pond which can be used to pass water to Long Pond.

The seven generating units at Bay d'Espoir utilize approximately 176 m of head to produce a rated output of 613.4 MW with a rated flow of 397 m^3/s. The plant produces an average of 2.7 TWh annually, making it the largest hydroelectric plant on the island portion of Newfoundland and Labrador.

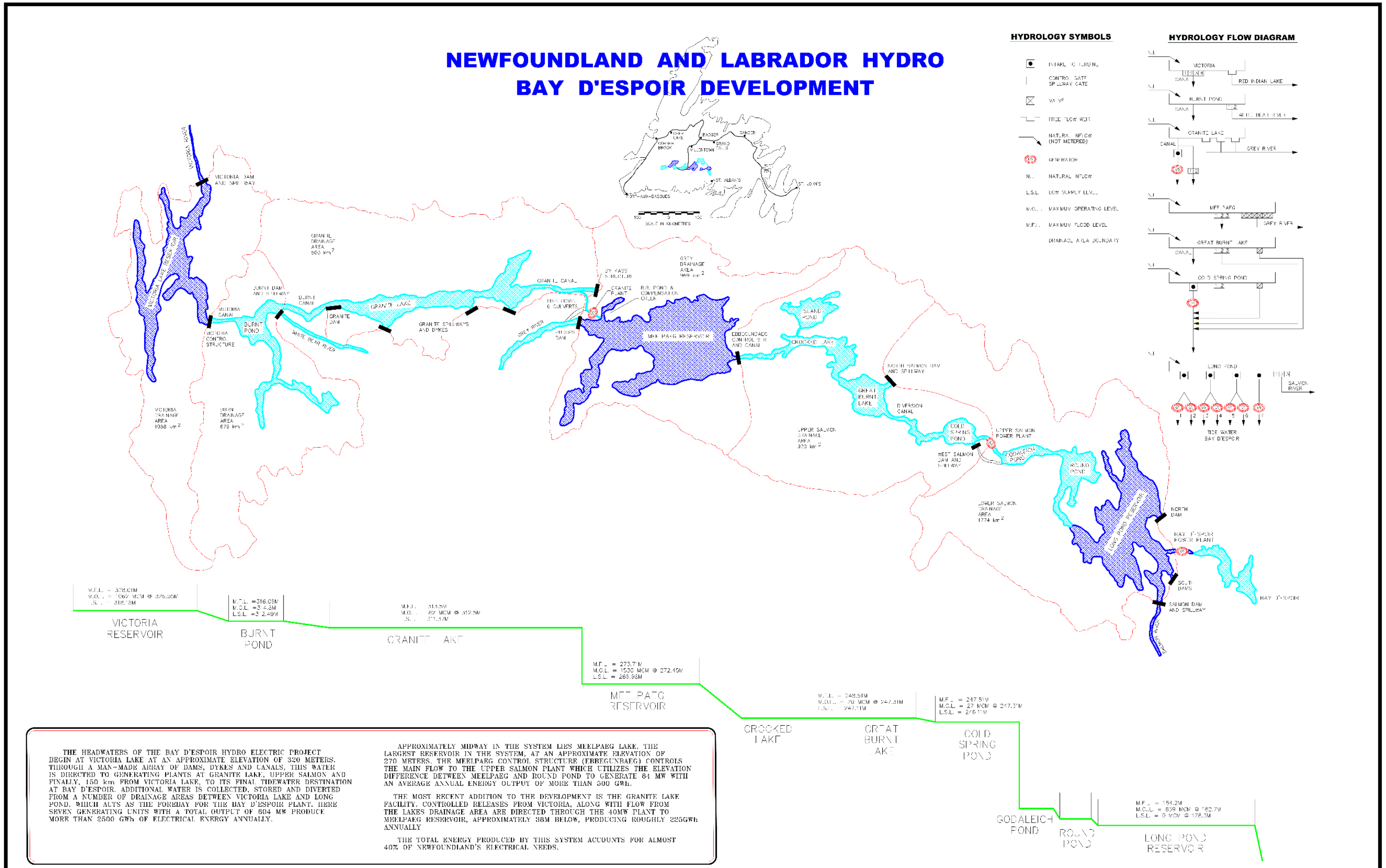

Figure 2-2: Bay d'Espoir System – General Arrangement

Table 2-1: Reservoir Characteristics from Major Reservoir Operations Manual (Hydro, 2015)

Reservoir Name	Low Supply Level (m)	Max. Operating Level (m)	Storage at Max. Operating Level (Mm^3)	Drainage Area (km^2)
Victoria Lake	318.15	326.05 – 326.41(1)	1,062 (at 326.05 m) 1,122 (at 326.41 m)	1,058
Burnt Pond	-	314.76	39	679
Granite Lake	308.89(2) 311.37	312.53	82	503
Meelpaeg Lake	266.98	271.59 – 272.45(1)	1,250 (at 271.59 m) 1,535 (at 272.45 m)	969
Great Burnt Lake	247.11	247.31	20	630
Cold Spring Pond	246.11	247.31	27	290
Long Pond	178.31	180.25 – 182.70(1)	360 (at 180.25 m) 839 (at 182.70 m)	1,774

Notes: (1) range varies with season
(2) emergency low supply level

2.2 Physiography and Climate

The Island of Newfoundland represents the north-eastern most extension of the Appalachian Mountain system in North America. The physiography of the island of Newfoundland (Figure 2-3) consists primarily of a tilted plateau which is higher in the west than in the east. The highland areas in the west range from 200 to 600 m above sea level, with some peaks rising over 750 m. The central part of the Island has an elevation which ranges from 180 to 300 m. The eastern part of the Island is at a generally lower elevation and has undulating topography where only isolated peaks reach an elevation of 300 m. The Bay d'Espoir system is located on the southern, seaward side of this plateau.

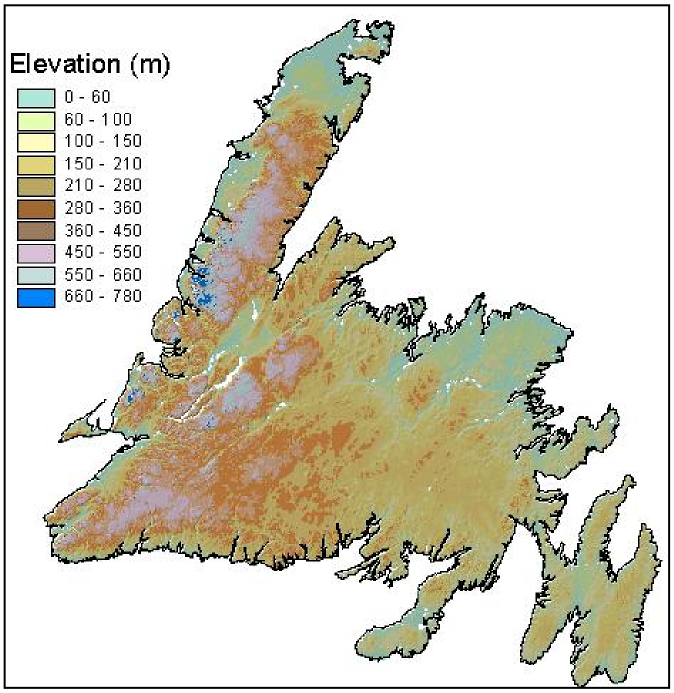

Figure 2-3: Topography of Newfoundland

The climate of Newfoundland is classified as a cool snow forest climate with no distinct dry season and cool to warm summers. In the southern part of the Island, including much of the Bay d'Espoir system, temperatures can range from -35°C in winter to highs in the mid-20s or higher in the summer. Winter snow cover in southern Newfoundland usually melts between April and early June but starting times and melt rates vary from year to year.

The mean annual precipitation on the Island (Figure 2-4) ranges from 1000 mm to over 1700 mm. For the Bay d'Espoir system, the mean annual precipitation ranges from about 1400 mm at the headwaters near Victoria Lake to 1600 mm at Long Pond.

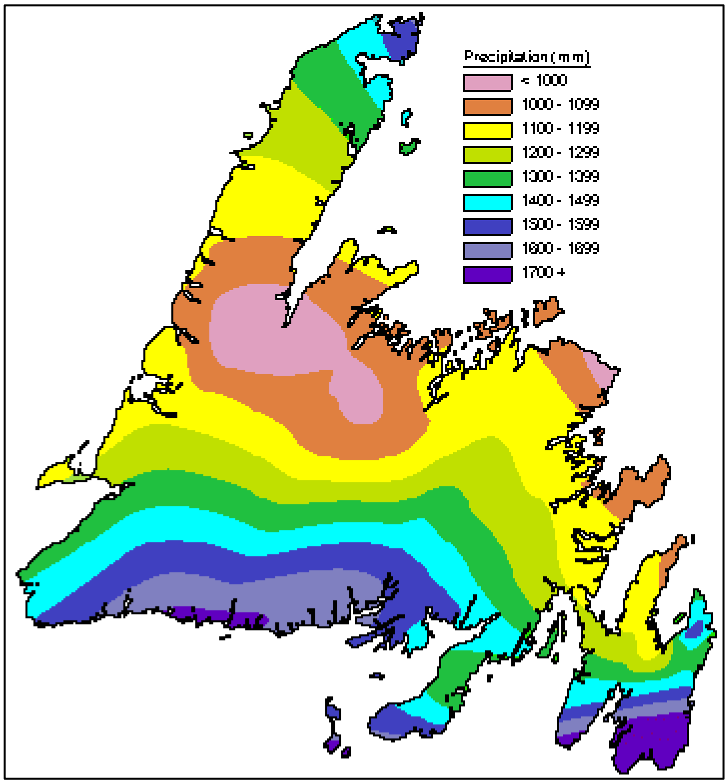

Figure 2-4: Mean Annual Precipitation

2.3 Data and Records

Records reviewed for this study, based on information provided by Hydro and information in Hatch's archives, is summarized in Table 2-2.

Table 2-2: List of Data Sources

Document Title	Date	Prepared by
Engineering Feasibility Study of the Proposed Bay d'Espoir Hydroelectric Generating Unit 8	2018	SNC-Lavalin
Major Reservoir Operation Manual Revision 5	2015	NL Hydro
Full record of historical inflow data for the Bay d'Espoir system	1950-2019	NL Hydro
Full record of spillage data for the Bay d'Espoir system	Varies - 2019	NL Hydro
Full record of reservoir level data for the Bay d'Espoir system	Varies - 2019	NL Hydro
Granite Canal Fish Habitat Management Standard Instruction	2015	NL Hydro
Fisheries Releases at Pudops (Grey River) and Burnt Spillway (White Bear River) Standard Instruction	2015	NL Hydro
Full record of historical generation data for Granite Canal, Upper Salmon and Bay d'Espoir	1996-2019	NL Hydro
O&M Manual for Granite Canal Hydro Generating Station	2005	GE Hydro
O&M Manual for Upper Salmon Hydro Generating Station	1983	Acres
O&M Manual for Bay d'Espoir Hydro Generating Station	Not Available	Shawmont
Probable Maximum Flood Study for the Bay d'Espoir Hydroelectric Development	2019	Hatch
Standard Operating Instruction BA-P-032 (T-085) Frazil Ice Procedure	2019	NL Hydro
Storage Curves for Bay d'Espoir System	Varies	NL Hydro
Environment Canada Meteorological Gauges located within the Bay d'Espoir System	Varies - 2019	Environment Canada
Water Survey of Canada Hydrometric Gauges	Varies - 2019	Environment Canada
Island Hydrology Review	2003	SGE Acres
Adjustment of Bay d'Espoir Reference Inflow Sequences	2004	SGE Acres
Island Load Profile	2020	NL Hydro
Turbine Generator Technical Specification	2017	SNC-Lavalin
Frazil Ice Historical Data	Varies - 2019	NL Hydro

2.4 Island Hydrology Review (2003)

In 2002, Hydro commissioned SGE Acres to carry out a study of hydrological issues related to estimation of its hydroelectric energy production. The study (SGE Acres, 2003) reviewed Hydro's data and methodology for estimating annual hydroelectric capability on the Island of Newfoundland, recommended the appropriate length of hydrologic record to use to develop the estimate, and also addressed trends and anomalies in the hydrologic record. The study concluded that some of the reference inflow series in the Bay d'Espoir system demonstrated minor internal inconsistencies, arising from differences in the methods of flow derivation employed for different periods. The study also concluded that the inconsistencies would have only a small effect on the estimates of average energy but should be corrected. Analysis of Hydro's inflow series and records from other independently gauged basins on the Island for the period 1950 to 2002 did not show any definitive natural trends or changes.

2.5 Adjustment of Bay d'Espoir Reference Inflow Sequences (2004)

Following the 2003 study, SGE Acres was retained by Hydro to adjust its Bay d'Espoir reference inflow sequences to make them internally consistent and free of random and systematic errors as demonstrated by appropriate statistical and graphical tests (SGE Acres, 2004).

Two types of adjustments were required. The first was an adjustment to the flows estimated for the pre-project period. These had originally been estimated for some of the Hydro basins using the standard technique of transfer from nearby gauged basins, using factors based on drainage area and mean annual runoff. The 2004 study adjusted the transfer factors slightly, using the additional body of data by then available from the Hydro basins themselves.

The second type of adjustment related to internal basin accounting, in particular, water transfer from Meelpaeg to Upper Salmon. The 2004 study found that the data and the records used to calculate the water transfer were sound, but that an alternative approach was needed to re-estimate the inflow series for the Meelpaeg, Upper Salmon and Lower Salmon sub-basins. The study recommended that Hydro make additional measurements to verify or redevelop the elevation-discharge curves for the Ebbegunbaeg control structure for future use and then recalculate the inflows to confirm the distribution of inflows among the sub-basins.

2.6 Feasibility Study (2018)

In June 2017, SNC-Lavalin Inc. (SLI) was retained by Hydro to perform an engineering study to add Unit 8 (150 MW installed capacity) at the Bay d'Espoir power plant (SLI, 2018a). The objective of the study was to define the project scope of work, prepare a master project execution schedule, and produce a class 3 cost estimate. Construction management was assumed to be in the form of an Engineering, Procurement and Construction Management (EPCM) type contract, with the EPCM firm also performing commissioning on behalf of the owner. The feasibility study mandate included the following main activities:

- Basic engineering to produce a class 3 cost estimate. The study was based on site condition information readily available in existing Hydro files when Unit 7 was constructed, and a site walk through. No new site condition investigations were performed (i.e., geotechnical surveys).
- Preparation of turbine and generator technical specifications as well as technical sheets for other major equipment to get budgetary prices from suppliers.
- Development of a 3D model of the new powerhouse from headrace to tailrace channel.
- Production of general arrangement drawings.
- Class 3 estimate.
- Development of a project execution plan with a preliminary schedule.
- Feasibility Study Report.

The scope of the SLI feasibility study did not include hydrological analysis, power and energy analysis, or capacity optimization.

The SLI feasibility study included an overview of required approvals under provincial and federal environmental legislation. Potentially applicable permits and authorizations relevant to the water environment include those listed under the NL Water Resources Act, federal Fisheries Act, and federal Navigation Protection Act and Regulations. The study noted that flow and current speed downstream of the plant could be modified due to increased peaking production resulting in lower minimum flows and higher peak flows with both powerhouses at full capacity. The modification of the outflow at the power station might result in bank erosion and could also locally affect the aquatic environment. The construction of the new entrance channel, the new intake and the enlargement of the existing headrace channel and tailrace will be conducted in or near waterbodies that potentially support fish habitat. Construction activities might interact with fish habitat. Operation and maintenance are not expected to result in significant adverse environmental effects on aquatic fauna and habitats.

2.7 Description of New Facility

The description of the new Unit 8 facility is extracted from SLI (2018a, 2018b).

Powerhouse 1 has six generating units of 76.5 MW nominal capacity each and three individual intakes and penstocks each supplying two units through a bifurcation near the powerhouse. The first four units were commissioned in 1967 (Bay d'Espoir phase 1) and the last two units (phase 2) were commissioned in 1977. A single headrace canal provides water to the three intakes and the powerhouse discharges via a 4.5 km long tailrace channel which flows into Bay d'Espoir.

Bay d'Espoir Powerhouse 2 contains a single unit of 154.4 MW nominal capacity (Unit 7). Water is provided by a separate headrace channel, intake and penstock. This powerhouse discharges in its own tailrace channel connecting Powerhouse 2 to the tailrace channel of Powerhouse 1. Powerhouse 2 was commissioned in 1977 (phase 3) and was constructed for the future installation of a second unit. The construction of Powerhouse 2 included rock excavation for the second unit and downstream portion of the draft tube with the draft tube gates guides, so as to enable installation of the future Unit 8 without impacting the operation of the existing Unit 7.

There is considerable head loss in the three 2-unit combined penstocks of Units 1 to 6 compared to Unit 7. With one unit at capacity (76.5 MW) in each of the three combined penstocks, the loss is 5.98 m. When two units are at capacity on the same penstock, they can attain 150 MW (75 MW each) and the loss increases to 14.24 m. The penstock loss for Unit 7 running at capacity (154.4 MW) is only 5.65 m. Therefore, operation of Unit 7 is more efficient than each of Units 1 to 6.

The new facility will include the following elements:

- An enlarged headrace channel including a bifurcation excavated in the rock and supplying both the existing entrance channel to Unit 7 intake and the new entrance channel to Unit 8 intake.
- A new water intake similar to the existing Unit 7 intake.
- A new buried steel penstock connecting the new intake to the new generating unit.
- A new 154.4 MW generating Unit 8 with an additional service bay as part of Powerhouse 2 next to existing Unit 7. The new unit will be built in the existing excavations, upstream of the draft tube outlet, done in the 1970s as part of the construction of Powerhouse 2.
- A high voltage 230 kV line from the Unit 8 step-up transformer to Terminal Station No 2 (TS-2) with the addition of a new breaker-and-a-half diameter to receive the new line.

The new facility will utilize the existing powerhouse forebay and does not require the construction of any additional dams.

Unit 8 will use a draft tube similar to Unit 7 with a minor modification to reduce head losses. The generating unit equipment will be designed to modern standards.

The unit will have a nominal combined efficiency of 0.916 and a transformer efficiency of 0.99. The penstock loss at capacity (154.4 MW) is 5.81 m. Additionally, tailrace channel expansion is recommended in the SLI report, to minimize any increase in tailwater elevation that could result from increased plant discharge with the addition of Unit 8.

3. Hydrological Analysis

The study required a hydrological analysis of the Bay d'Espoir system, including a detailed analysis from 1970 to present and a limited review of the full record. Hydro provided reference inflow series dating back to 1950; the period 1970 to present includes the operational period of the Bay d'Espoir Hydroelectric Generating Station.

The analysis is documented in Appendix A of this report. The Hydro reference inflow series are provided in Appendix B.

The analysis concluded that the reference inflow may be used as provided, for the power and energy analysis of the proposed new Unit 8.

4. Modelling Approach

Hatch used its proprietary Vista Decision Support System (DSS) model suite for the study of impacts of Unit 8 on the Bay d'Espoir system. The DSS has been implemented for Nalcor assets including the Upper Churchill, Lower Churchill, Exploits River and the integrated Island systems. For this study, the model configuration is limited to the Bay d'Espoir system.

A credible hydrologic/power and energy model requires a large amount of effort to be invested in the model setup, including collection and validation of data, calibration to multiple actual observed events, and verification of the model suitability and results. Fortunately for the present assignment, a calibrated and verified Vista DSS model of the Bay d'Espoir development has been in active service with Hydro for more than ten years. It is used operationally for long term and short term generation planning.

4.1 Topology

The schematic of the Bay d'Espoir model setup in Vista is provided in Figure 4-1 below and it includes all reservoirs, ponds and flow paths. Detailed characteristics of generation facilities and conveyances are modelled, including:

- Elevation-storage relationship
- Unit characteristics
- Tailwater relationship
- Spill structures
- River reach routing.

It was assumed that the tailrace channel expansion recommended by SLI (2018b) with the addition of Unit 8 will be implemented. Therefore, the tailwater relationship in Vista was adjusted such that the tailwater level at the full discharge of the expanded plant is the same as the level at full discharge of the existing plant.

4.2 Operational Constraints and Frazil Ice Consideration

Vista has a large library of operational constraints that are used to capture license, environmental and operational limitations. The Vista setup includes:

- Limits on reservoir minimum and maximum levels.
- Environmental flow releases for fish, including flows to the White Bear River, Grey River and for Burnt Pond Outflow.
- Constraints on Granite Canal plant operations for Compensation Creek.
- Seasonal rule curves for Victoria, Meelpaeg and Long Pond.

- Elevation and flow constraints for stable ice cover on Burnt Canal.

The constraints in the existing Vista setup were reviewed and confirmed that they are consistent with the Major Reservoir Operations Manual (Hydro 2015) and other relevant operating guides. In addition, periods of outages and limited capacity operations were defined for Granite Canal and Upper Salmon hydro plants in consideration of frazil ice mitigation.

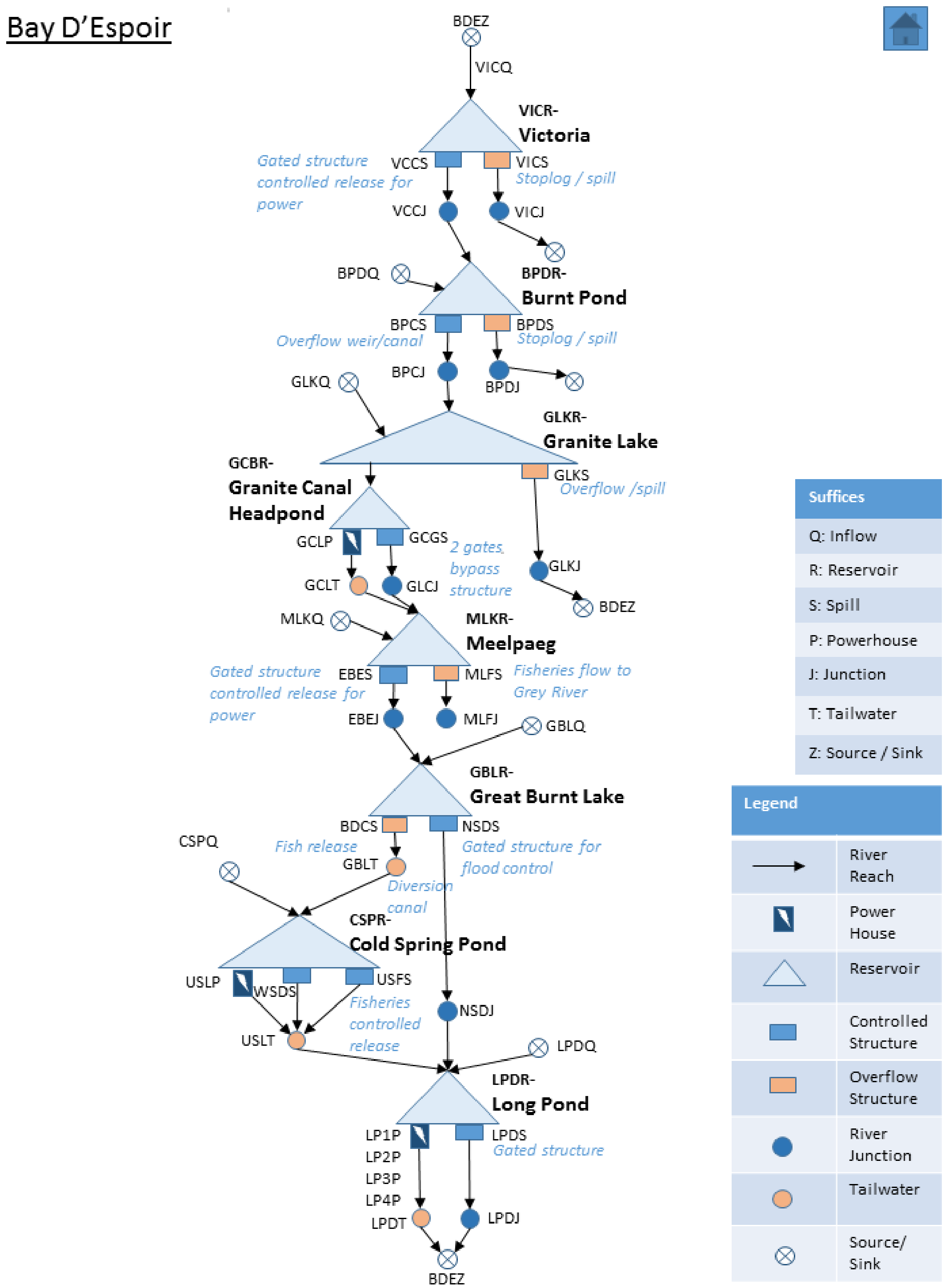

Figure 4-1: Bay d'Espoir Vista Schematic

5. Model Analyses

The LT Vista module was used to perform the energy analyses in this study using all the 70 years of provided hydrologic record earlier reviewed in Appendix A of this report. The hydrology data was compared to the hydrology data in the Hydro Vista operations database and was found to be the same. LT Vista facilitates studies of long-term assessments and planning using long periods of hydrology.

The model was based on water-balance continuity where flow release decisions are constrained by physical limits and operating rules defined in the setup. The time step as defined in LT Vista is referred to as the period and is specified by the user. Typical period durations are months or weeks but can also be defined as multiples of a day or multiples of a week. The user also defines daily sub-periods within a week, i.e., on-peak, off-peak, shoulder-peak etc., hours for each day in a typical week and there could be as many sub-periods as desired. In model analyses, the average load and price over each period and sub-period are key drivers in the optimization, along with the defined constraints. In this assessment, the Island load profile provided by Hydro varies daily and over each sub-period (within the period). Therefore, the sub-periods should be selected so that derived energy is properly influenced by the provided load profile, i.e., higher generation during higher load sub-periods. The provided Island load for 2020 was analyzed to properly select the sub-periods. Figure 5-1 shows the average hourly weekday and weekend load profile for the given load.

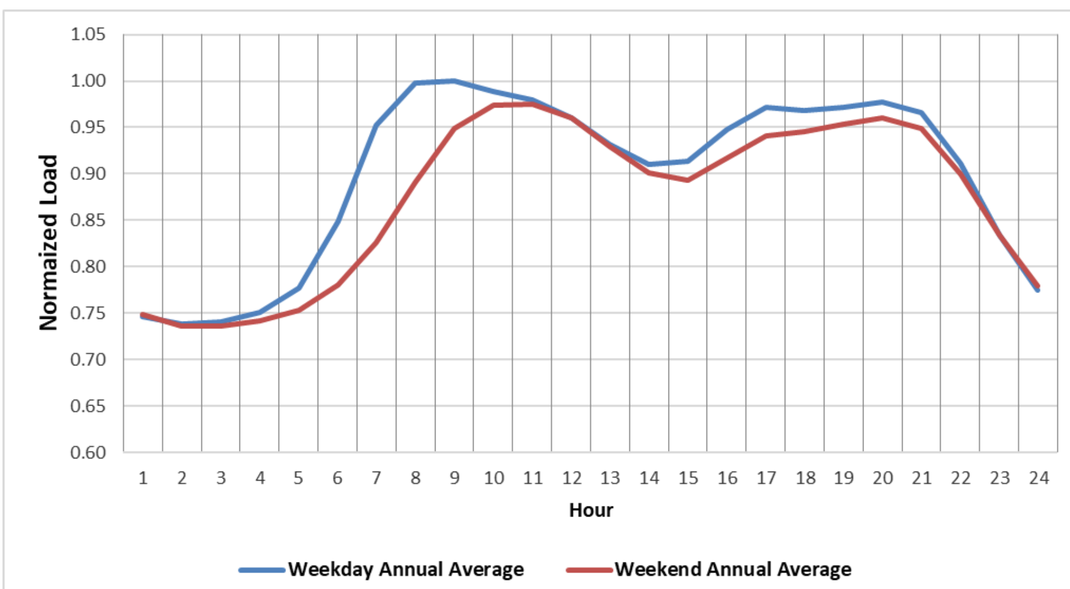

Figure 5-1: 2020 Island Load Annual Weekday and Weekend Average Load Profiles

The following four sub-periods can be identified from the figure.

- Early hours/late night low load or off-peak period, longer for the weekend and the weekend.
- Morning and mid-day and night high load or shoulder-peak period.
- Morning higher load or peak-period, longer for the weekday than the weekend.
- Evening higher load or peak-period.

It can also be seen that the weekday non off-peak loads are typically higher than the weekend values. Therefore, eight weekly sub-periods (4 for weekday and 4 weekend) were defined for this study as shown in Table 5-1.

Table 5-1: Modelled Weekly Sub-Period Definition

Hour	Mon	Tue	Wed	Thur	Fri	Sat	Sun
1	2	2	2	2	2	1	1
2	2	2	2	2	2	1	1
3	2	2	2	2	2	1	1
4	2	2	2	2	2	1	1
5	2	2	2	2	2	1	1
6	2	2	2	2	2	1	1
7	4	4	4	4	4	1	1
8	6	6	6	6	6	1	1
9	6	6	6	6	6	3	3
10	6	6	6	6	6	5	5
11	4	4	4	4	4	5	5
12	4	4	4	4	4	5	5
13	4	4	4	4	4	3	3
14	4	4	4	4	4	3	3
15	4	4	4	4	4	3	3
16	4	4	4	4	4	3	3
17	8	8	8	8	8	3	3
18	8	8	8	8	8	7	7
19	8	8	8	8	8	7	7
20	8	8	8	8	8	7	7
21	4	4	4	4	4	7	7
22	4	4	4	4	4	3	3
23	2	2	2	2	2	1	1
24	2	2	2	2	2	1	1

1 (2)	Off-Peak
3 (4)	Shoulder-Peak
5 (6)	Morning-Peak
7 (8)	Evening- Peak

5.1 Firm Energy Analysis

For a hydroelectric system, firm energy is the amount of electricity that can be generated over the most adverse sequence of hydrology, called the critical period. To determine the firm energy, simulations were carried out for the full hydrologic record. LT Vista run time depends on the model time step. The longer the time step, the shorter the run time. The run time increases exponentially as the time step decreases. Therefore, the analysis was carried out in two phases. In phase one, simulation was carried out over the full hydrologic records using a monthly time step to identify the critical period and an initial estimate of the firm energy. In phase two, a more detailed simulation was carried out using a daily time step to more accurately define the firm energy. Plant operation to manage frazil ice formation was considered in both phases based on the following operational assumptions at Granite Canal and Upper Salmon plants:

Granite Canal Plant:

- December: three nights in a row, 8 h/night, when the plant is limited to 30 MW.

Upper Salmon Plant:

- December: four nights in a row of shutdown for 12 h/night.
- January and February: one week in each month during which the plant is limited to 50 MW.

5.1.1 Critical Period Analysis

LT Vista was run in monthly time step to simulate operations over a 70-year continuous period with a fixed annual load for the existing system with the Upper Salmon bypass. The load shape is defined by the provided 2020 Island load. The annual load was gradually increased until the system experienced failure to meet the load. For this analysis, the starting water levels in each reservoir in the system were assumed to be the maximum operating level (MOL) or upper rule curve for each reservoir and time of year, as specified in the Major Reservoir Operations Manual (Hydro 2015). The total Bay d'Espoir system storage was monitored in order to establish system failure and determine the critical period.

The total system storage trajectories are illustrated in Figure 5-2. As shown in Figure 5-2, the total system storage drops to its minimum level in 1962. The LT simulation indicates that the critical sequence occurs between January 1959 (when system storage was full considering upper rule curves and maximum operating levels of the reservoirs) and March 1962 when the system storage drops to minimum.

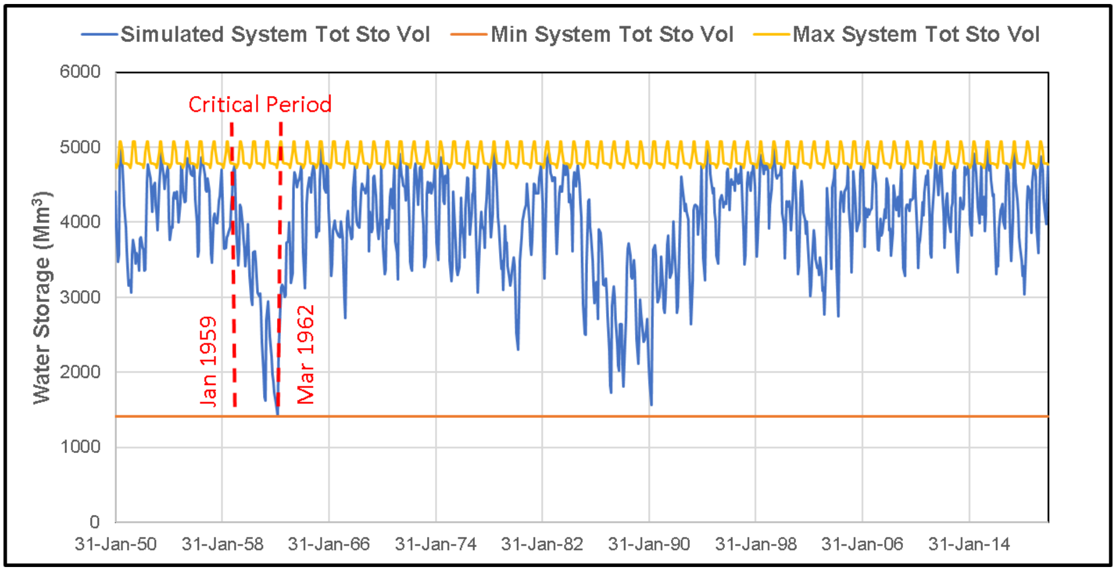

Figure 5-2: System Total Storage Trajectory

5.1.2 Detailed Analysis Using Daily Time Step

Once the critical period had been identified, LT Vista was run from January 1959 to December 1962 using a daily time step for trial annual loads close to 300 MWc. Again, the total system storage was monitored for each load trial to identify the smallest load value that would cause the storage, starting full, to be depleted in the critical period. The detailed analysis was performed for both the existing system with Upper Salmon bypass and the existing system plus Unit 8 and the Upper Salmon bypass.

The shape for each of the load trials is defined by the given 2020 Island load. The final estimate of the firm energy is 297.0 MWc (with peak load of 541 MW) for the existing system and 297.5 MWc (with peak load of (542 MW) for the existing system plus Unit 8. Figure 5-3 shows the trajectory of the system storage under the existing system firm energy. Both the existing system and the existing system plus Unit 8 annual loads have the same capacity factor of 0.5485 as the 2020 Island load. Figure 5-4 shows a comparison of the existing system annual firm load with 2020 Island load. As such it can be determined that the addition of Unit 8 does not impact the firm energy of the Bay d'Espoir plant.

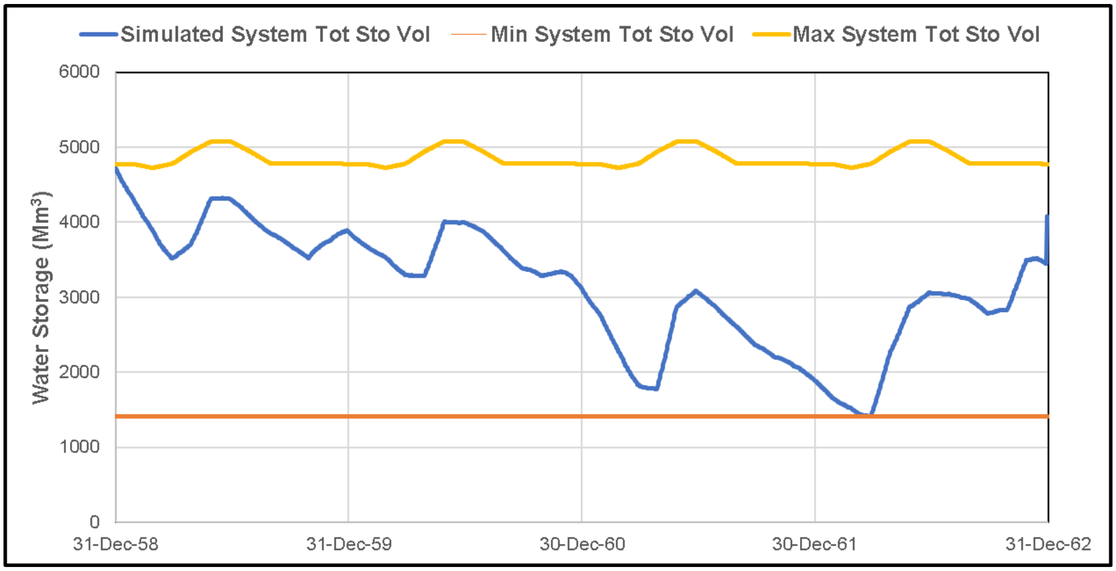

Figure 5-3: Simulated Firm Load System Total Storage Trajectory

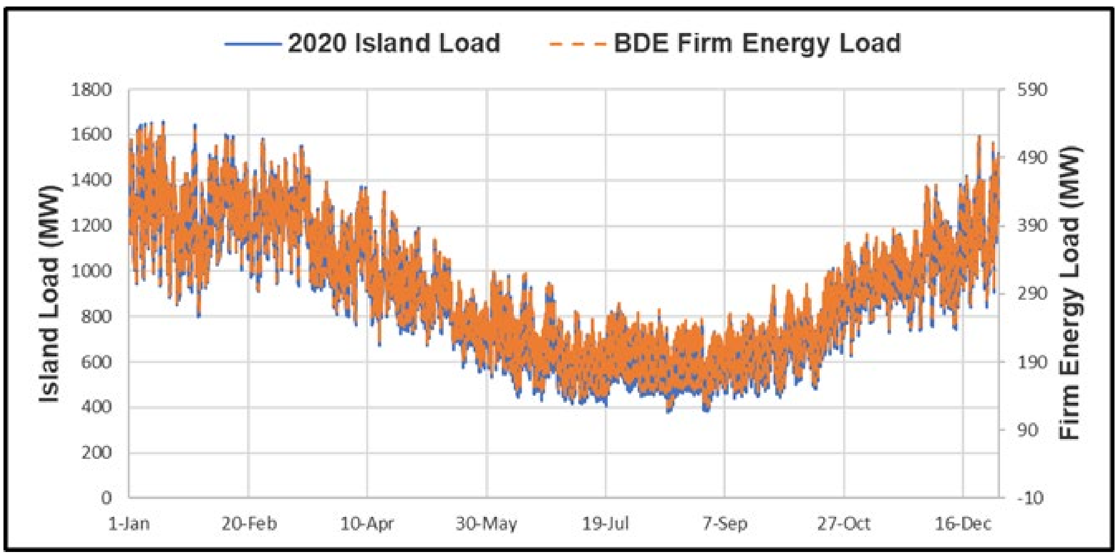

Figure 5-4: Comparison between Hourly 2020 Island Load and Hourly Bay d'Espoir Firm Energy Load

5.2 Energy Capability Analysis

To estimate the energy capability of the Bay d'Espoir system, LT Vista was run to optimize capacity while respecting the firm load requirement. For this purpose, the firm load established in Section 5.1.2 for the existing system was imposed on the system along with market opportunity to capture secondary energy. In order that the market price reflects the Island system load, and as such the capacity requirement, the hourly market price is set at the hourly load value of the 2020 Island load provided by Hydro. The analysis was performed with the constraints listed in Section 4.2 and frazil ice consideration based on the following operational assumptions at Granite Canal and Upper Salmon plants:

Granite Canal Plant:

- December: three nights in a row, 8 h/night, when the plant is limited to 30 MW.

Upper Salmon Plant:

- December, January and February: three nights in a row of shutdown for 12 h/night in each month.

In order to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system, LT Vista was run for the following four scenarios:

- Existing system with Upper Salmon bypass
- Existing system without Upper Salmon bypass
- Existing system plus Unit 8, with Upper Salmon bypass
- Existing system plus Unit 8, without Upper Salmon bypass.

All the runs were conducted over the 70-year continuous period of available hydrology. An important consideration over such a long run horizon is the analytical time step or period and sub-periods. LT Vista run time and computer memory requirement are significantly influenced by the analytical time step. The longer the time step, the shorter the run time and the smaller the computer memory requirement. Both run time and memory requirement increase exponentially as the analytical time step shortens. For a system the size of the Bay d'Espoir system and a 70-year run, the time step must be chosen to not over-task available computer resources. After experimentation with several time step durations, a nominal five-day period was used for this assessment. The time step at the end of each calendar month was adjusted so that this time ended at the month boundary. The sub-periods established in Section 5 (see Table 5-1), so that derived energy is influenced by the 2020 Island load profile and the system capacity is properly captured, was used for each run.

The results of the energy analysis are presented in Table 5-2 as average annual energy for the Bay d'Espoir system and the contribution from each plant, for each of the four scenarios. The difference and percent difference for the other three scenarios relative to the existing system with Upper Salmon bypass are also presented in the table. The following can be inferred from the table:

- Granite Canal plant average annual energy remains approximately 234 GWh for all four scenarios.

- There is only a very slight reduction in average annual energy for the existing system without Upper Salmon bypass.
- There is a similar level of increase, 0.67 percent, in the system average annual energy with the addition of Unit 8 with and without the Upper Salmon bypass.
- The average annual energy contributed by the Upper Salmon plant dropped by 1.92 percent and 1.68 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.
- The average annual energy contributed by the Bay d'Espoir plant increased by 1.26 percent and 1.22 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.

Table 5-2: Average Annual Energy for Bay d'Espoir System and the Contributing Plants

Scenario	Total System	Granite Canal Plant	Upper Salmon Plant	Bay d'Espoir Plant
Average Annual Energy (GWh/year)				
Existing system with Upper Salmon bypass	3,394.11	234.01	542.46	2,617.65
Existing System without Upper Salmon bypass	3,392.92	233.98	541.90	2,617.04
Existing system plus unit 8, with Upper Salmon bypass	3,416.74	234.07	532.03	2,650.64
Existing system plus unit 8, without Upper Salmon bypass.	3,416.91	234.00	533.35	2,649.57
Difference Relative to Existing system with Upper Salmon bypass (GWh)				
Existing System without Upper Salmon bypass	-1.19	-0.03	-0.56	-0.61
Existing system plus unit 8, with Upper Salmon bypass	22.63	0.06	-10.43	33.00
Existing system plus unit 8, without Upper Salmon bypass.	22.79	-0.01	-9.11	31.92
Difference Relative to Existing system with Upper Salmon bypass (%)				
Existing System without Upper Salmon bypass	-0.04	-0.01	-0.10	-0.02
Existing system plus unit 8, with Upper Salmon bypass	0.67	0.03	-1.92	1.26
Existing system plus unit 8, without Upper Salmon bypass.	0.67	-0.01	-1.68	1.22

5.3 Detailed Model Results

Detailed model results are presented in the following subsections as tables, duration curves and monthly box plots. The centered-vertical line of the box plots extends from the minimum value to the maximum value. The horizontal line in the box is the median and the lower and upper ends of the box represents the 25th percentile and 75th percentile respectively. Where tables are presented for off-peak and on-peak values, the on-peak hours are hours 7 to 22 each day of the week, and the off-peak hours are hours 1 to 6, 23 and 24 each day of the week.

5.3.1 Firm Energy

Firm annual energy of the existing system and the existing system plus Unit 8 were estimated as 297.0 MWc and 297.5 MWc respectively. The difference of 0.17 percent is attributable to increased efficiency of the Bay d'Espoir plant due to the new unit. This is expected, as there is no spill at the plant with the existing system, so no recovery of energy with addition of the unit. The system annual firm energy of the existing system of 297.0 MWc (2,601.72 GWh) is therefore adopted for the system. The corresponding annual firm energy for the Bay d'Espoir plant is 2,095.97 GWh. The corresponding total, on-peak and off-peak firm monthly energy for the system along with contributions from each plant are presented in Table 5-3.

Table 5-3: Firm Monthly Energy (GWh) for Bay d'Espoir System and the Contributing Plants

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	System			**Granite Canal Plant**		
January	300.88	211.07	89.82	21.16	15.17	5.98
February	278.75	192.17	86.57	19.57	13.94	5.63
March	274.41	187.21	87.20	20.20	14.26	5.94
April	230.68	158.03	72.65	15.47	10.82	4.66
May	194.05	133.86	60.19	16.55	11.57	4.98
June	158.95	113.18	45.77	10.80	7.40	3.40
July	151.24	108.34	42.89	11.71	7.58	4.13
August	145.97	105.12	40.85	10.10	6.73	3.37
September	152.43	108.51	43.91	8.87	5.89	2.98
October	195.09	136.97	58.12	14.01	9.17	4.84
November	235.34	163.42	71.91	19.64	13.25	6.40
December	283.94	198.78	85.17	20.17	13.61	6.56
	Upper Salmon Plant			**Bay d'Espoir Plant**		
January	35.44	23.79	11.65	244.29	172.11	72.18
February	32.82	21.86	10.96	226.36	156.37	69.99
March	33.93	22.36	11.58	220.27	150.59	69.68
April	26.03	16.96	9.07	189.18	130.26	58.92
May	27.83	18.13	9.70	149.67	104.17	45.51
June	18.22	11.61	6.62	129.92	94.16	35.76
July	19.92	11.88	8.04	119.61	88.89	30.72
August	17.11	10.55	6.57	118.76	87.85	30.91
September	15.04	9.24	5.80	128.51	93.38	35.13
October	23.81	14.38	9.44	157.27	113.42	43.84
November	33.22	20.77	12.46	182.48	129.41	53.06
December	34.11	21.34	12.77	229.66	163.82	65.84

5.3.2 Average Monthly Energy

The average annual energy for each scenario was presented in Table 5-2. The total, on-peak and off-peak average monthly energy for the system along with contributions from each plant, are presented in Table 5-4 to 5-7. It will be noted that there is general increase in the on-peak generation and decrease in off-peak generation for the river system and Bay d'Espoir plant with addition of Unit 8. The monthly on-peak and off-peak generation at Granite Canal and Upper Salmon plants remain essentially the same with addition of Bay d'Espoir Unit 8. This change in distribution of generation at Bay d'Espoir plant is discussed further in Section 5.3.3 below.

Table 5-4: Average Monthly Energy (GWh) for Bay d'Espoir System

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing system with Upper Salmon bypass			**Existing System without Upper Salmon bypass**		
January	439.09	327.72	111.38	437.39	326.75	110.64
February	425.20	300.41	124.79	424.93	300.12	124.81
March	397.66	284.11	113.54	396.88	283.75	113.13
April	329.55	241.98	87.57	329.08	241.85	87.23
May	230.56	167.51	63.05	230.90	167.73	63.17
June	170.19	124.63	45.56	170.86	125.24	45.62
July	153.59	110.93	42.67	153.82	111.15	42.68
August	146.04	105.26	40.78	146.10	105.31	40.79
September	157.05	113.39	43.66	157.37	113.71	43.67
October	237.42	177.60	59.82	237.01	177.23	59.79
November	327.24	252.20	75.04	327.81	252.62	75.19
December	380.52	288.38	92.14	380.77	288.35	92.42
	Existing system plus Unit 8, with Upper Salmon bypass			**Existing system plus Unit 8, without Upper Salmon bypass**		
January	457.59	362.29	95.30	449.35	357.58	91.77
February	456.36	342.40	113.96	453.30	341.03	112.27
March	399.95	294.29	105.66	398.34	293.34	105.00
April	328.46	245.56	82.90	330.55	247.08	83.47
May	214.83	154.34	60.49	218.99	157.88	61.11
June	162.14	117.06	45.08	164.34	119.14	45.19
July	151.26	108.69	42.57	151.70	109.12	42.58
August	145.97	105.19	40.78	145.97	105.19	40.78
September	153.68	110.19	43.49	154.68	111.12	43.56
October	229.72	170.94	58.78	231.79	172.89	58.90
November	330.92	259.93	70.99	330.57	259.58	70.98
December	385.86	299.77	86.09	387.34	301.06	86.29

Table 5-5: Average Monthly Energy (GWh) for Granite Canal Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing system with Upper Salmon bypass			**Existing System without Upper Salmon bypass**		
January	26.40	19.37	7.03	26.32	19.36	6.96
February	24.92	17.73	7.19	24.90	17.71	7.19
March	25.02	17.96	7.06	25.03	17.93	7.10
April	21.27	15.84	5.43	21.33	15.88	5.46
May	22.67	16.69	5.98	22.67	16.67	6.00
June	13.89	11.73	2.16	14.11	11.87	2.24
July	11.69	9.05	2.64	11.30	8.98	2.32
August	11.06	8.41	2.65	11.40	8.71	2.69
September	11.88	8.82	3.06	11.67	8.85	2.82
October	18.29	12.88	5.41	18.39	13.04	5.35
November	22.26	16.37	5.88	22.23	16.36	5.87
December	24.66	18.35	6.31	24.61	18.35	6.26
	Existing system plus Unit 8, with Upper Salmon bypass			**Existing system plus Unit 8, without Upper Salmon bypass**		
January	27.13	19.30	7.83	27.31	19.40	7.92
February	24.92	17.63	7.29	25.06	17.65	7.41
March	24.91	17.72	7.19	24.93	17.75	7.19
April	21.22	15.56	5.66	21.16	15.53	5.62
May	22.82	16.52	6.30	22.81	16.49	6.32
June	14.15	11.50	2.64	14.07	11.59	2.47
July	12.27	8.59	3.68	11.92	8.78	3.13
August	10.72	7.73	2.99	11.05	7.88	3.17
September	11.63	8.49	3.14	11.40	8.41	2.99
October	17.82	12.52	5.29	17.79	12.49	5.30
November	22.01	16.00	6.02	22.02	16.02	5.99
December	24.47	18.06	6.41	24.47	18.02	6.45

Table 5-6: Average Monthly Energy (GWh) for Upper Salmon Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing system with Upper Salmon bypass			**Existing System without Upper Salmon bypass**		
January	59.19	40.40	18.79	58.82	40.15	18.67
February	53.02	36.16	16.86	52.92	36.08	16.84
March	60.57	40.39	20.18	60.54	40.48	20.06
April	57.02	38.21	18.81	56.56	37.85	18.72
May	52.73	35.33	17.40	52.56	35.28	17.28
June	40.71	28.77	11.94	40.57	28.66	11.91
July	28.33	21.49	6.84	29.05	21.94	7.11
August	20.73	16.26	4.47	20.75	16.05	4.70
September	23.27	17.82	5.45	23.32	17.34	5.98
October	39.45	28.19	11.26	39.30	27.42	11.87
November	50.29	34.78	15.51	50.41	34.55	15.85
December	57.13	39.30	17.83	57.11	39.21	17.90
	Existing system plus Unit 8, with Upper Salmon bypass			**Existing system plus Unit 8, without Upper Salmon bypass**		
January	59.27	40.44	18.83	58.56	39.95	18.61
February	53.08	36.19	16.89	52.79	35.97	16.82
March	60.77	40.53	20.25	60.66	40.52	20.14
April	56.53	37.77	18.76	56.32	37.63	18.69
May	52.60	35.09	17.51	52.50	35.18	17.33
June	39.66	28.01	11.65	40.05	28.10	11.96
July	24.10	18.94	5.16	25.72	19.20	6.53
August	19.40	15.22	4.17	19.76	15.45	4.30
September	22.57	17.06	5.51	23.20	16.70	6.50
October	37.15	25.84	11.31	37.30	25.23	12.07
November	49.99	33.81	16.18	49.70	33.39	16.31
December	56.91	39.08	17.83	56.79	38.90	17.89

Table 5-7: Average Monthly Energy (GWh) for Bay d'Espoir Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing system with Upper Salmon bypass			**Existing System without Upper Salmon bypass**		
January	353.51	267.95	85.56	352.26	267.25	85.01
February	347.25	246.52	100.74	347.10	246.32	100.78
March	312.06	225.76	86.30	311.31	225.34	85.97
April	251.26	187.93	63.33	251.18	188.13	63.06
May	155.15	115.49	39.66	155.67	115.78	39.88
June	115.59	84.14	31.45	116.18	84.71	31.47
July	113.57	80.39	33.18	113.47	80.23	33.24
August	114.25	80.59	33.66	113.95	80.55	33.40
September	121.90	86.75	35.15	122.38	87.51	34.87
October	179.68	136.53	43.15	179.33	136.76	42.56
November	254.69	201.05	53.64	255.17	201.71	53.46
December	298.73	230.73	68.00	299.05	230.80	68.25
	Existing system plus Unit 8, with Upper Salmon bypass			**Existing system plus Unit 8, without Upper Salmon bypass**		
January	371.19	302.55	68.64	363.48	298.23	65.24
February	378.36	288.58	89.78	375.44	287.41	88.04
March	314.27	236.05	78.22	312.75	235.08	77.67
April	250.71	192.23	58.48	253.08	193.91	59.16
May	139.41	102.73	36.68	143.67	106.22	37.46
June	108.33	77.55	30.78	110.22	79.45	30.77
July	114.89	81.15	33.73	114.06	81.14	32.92
August	115.85	82.24	33.61	115.16	81.86	33.30
September	119.48	84.64	34.84	120.09	86.02	34.07
October	174.75	132.58	42.18	176.69	135.17	41.53
November	258.91	210.12	48.79	258.85	210.17	48.68
December	304.48	242.63	61.85	306.09	244.14	61.94

5.3.3 Impact on Distribution of Generation at Bay d'Espoir Generating Station

Figure 5-5 shows comparison of the monthly box plot of the hourly generation at Bay d'Espoir plant. The following can be inferred from the figure:

- The optimized maximum hourly generation increased from near 600 MW for the existing plant to well over 700 MW, with the addition of Unit 8, in the fall to spring months of October to May.
- There is significant increase in optimized maximum generation in June and September with the addition of Unit 8.

- There is reduction in optimized maximum generation in July and August, with addition of Unit 8, an indication that energy is moved from these low load months to high load months.
- The 25th to 75th percentile spread in the winter months of December to March is much wider with the addition of Unit 8, an indication of significant energy movement from off-peak period to on-peak period in these high load months.

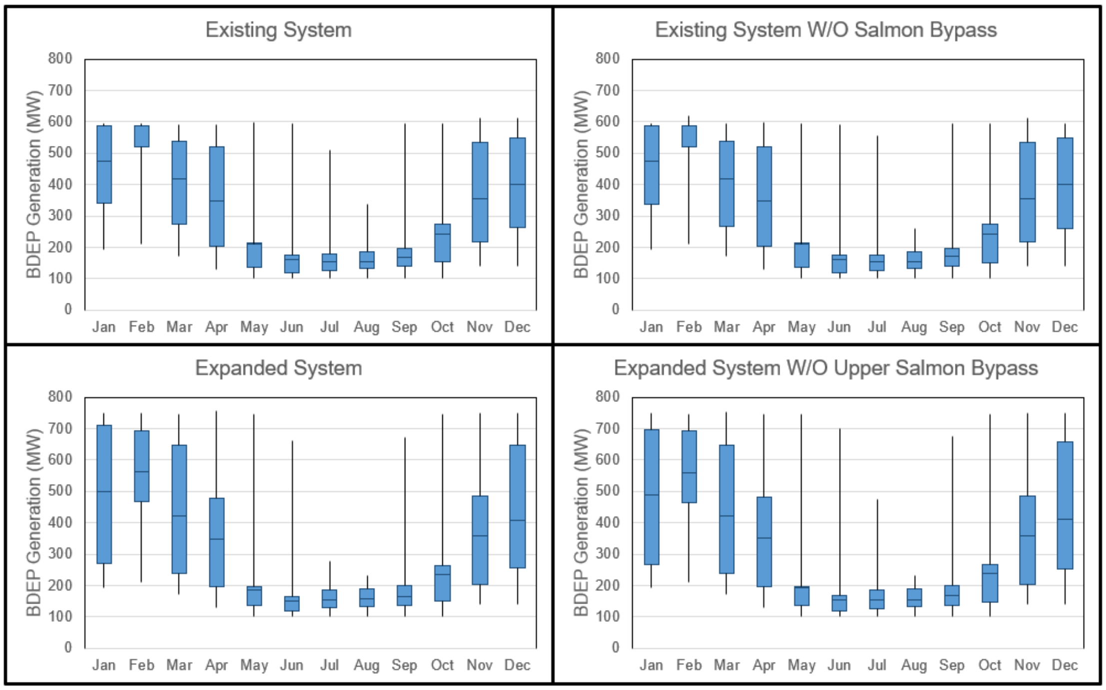

Figure 5-5: Variation in Hourly Bay d'Espoir Plant Generation by Month

Figure 5-6 shows comparison of the hourly generation duration curves of the four scenarios. The curves for existing system with and without Upper Salmon bypass are identical. Similarly, the curves for existing system plus Unit 8 with and without Upper Salmon bypass are identical. The figure has the following distinct segments.

- A segment representing 17.6 percent of the time when generation with addition of Unit 8 is higher than that of the existing system. These are typically on-peak hours.
- A second segment representing 29.7 percent of the time when generation with addition of Unit 8 is lower than that of the existing system. These are off-peak hours from which energy is moved to the on-peak hours.

- A third segment representing 52.7 percent of the time when generation with the existing and system and the expanded systems are identical. These are hours when the committed firm load is just met.

The optimized maximum generation for the existing Bay d'Espoir plant is 613.4 MW which increased to 754.1 MW with addition of Unit 8. This is an optimized increase of 140.7 MW during some of the on-peak hours. It is less than the 154.4 MW capacity of Unit 8 because gain in on-peak hour generation is at the expense of off-peak hour generation during which firm load must also be met. To increase on-peak hour generation to 154.4 MW will compromise meeting of firm load in some off-peak hours which will then have to be met from other resources.

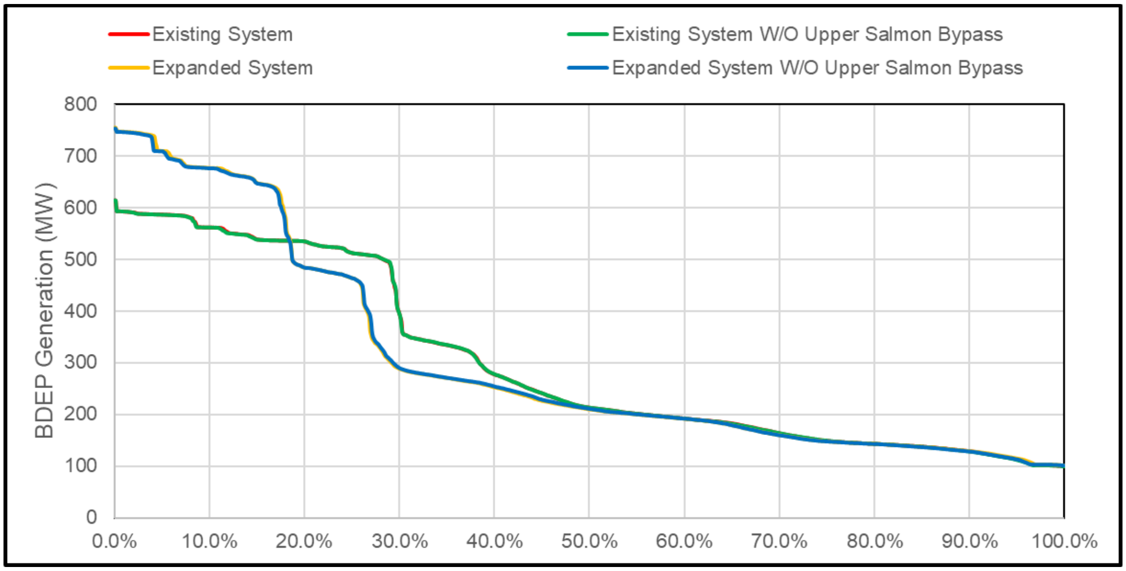

Figure 5-6: Duration Curves of Hourly Bay d'Espoir Plant Generation

It should be understood that the model does indeed employ Unit 8 at its full 154.4 MW capacity, being the first unit in scheduling order (discussed in Section 5.3.4 below). However, the model optimizes the total Bay d'Espoir plant output, with the objectives of meeting the defined firm every hour and maximizing average energy. Output at full rated capacity of the plant is possible, but there would be a tradeoff with reduced firm and average simulated energy. Likewise, increased duration of output in the high range (e.g., 700+ MW) is also possible, but with the tradeoff of reduced firm and average simulated energy. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW. Hydro's intent is not to generate more from the Bay d'Espoir plant on an energy basis, but rather to shift generation from the off-peak hours and non-winter period to the on-peak hours and winter period (i.e., Labrador-Island Link deliveries and/or other on-island generation can be used to replenish the Bay d'Espoir system during the off-peak periods).

Hatch has not examined the impact of water surface drawdown on adequacy of submergence at power intakes as part of this study. This is a hydraulic phenomenon that cannot be analyzed explicitly in a water management model such as Vista and it is recommended that it be examined in a separate hydraulic study. Otherwise, the information provided by Hydro on the hydromechanical equipment, head losses and tailwater do not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.

5.3.4 Impact on Efficiency of Bay d'Espoir Generating Station

Figure 5-7 shows a comparison of the hourly efficiency duration curve of the four scenarios. The curves for the existing system with and without Upper Salmon bypass are identical. Similarly, the curves for existing system plus Unit 8 with and without Upper Salmon bypass are identical. At the upper end of the curves, the efficiency of the existing system with Unit 8 is higher than that of the existing system by 0.0016. At the lower end of the curves, efficiency of the existing system with Unit 8 is higher than that of the existing system by 0.0125. On average, efficiency of the existing system with Unit 8 is higher than that of the existing system by 0.008. Each of the curve has three segments as will be understood with review of the unit commitment process represented by the efficiency versus flow plot shown in Figure 5-8.

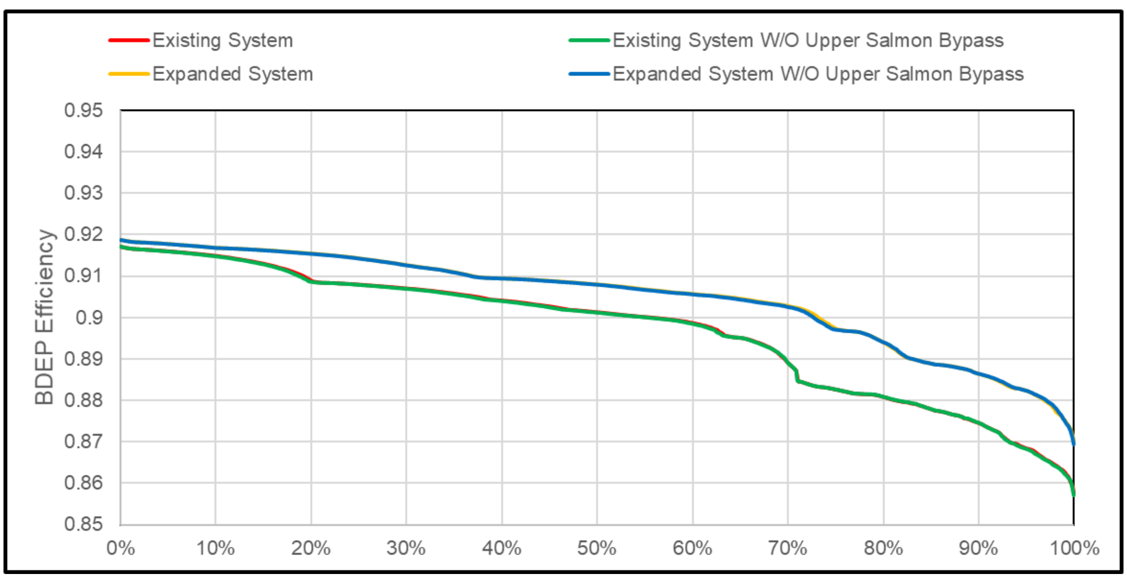

Figure 5-7: Duration Curves of Hourly Bay d'Espoir Plant Generation Efficiency

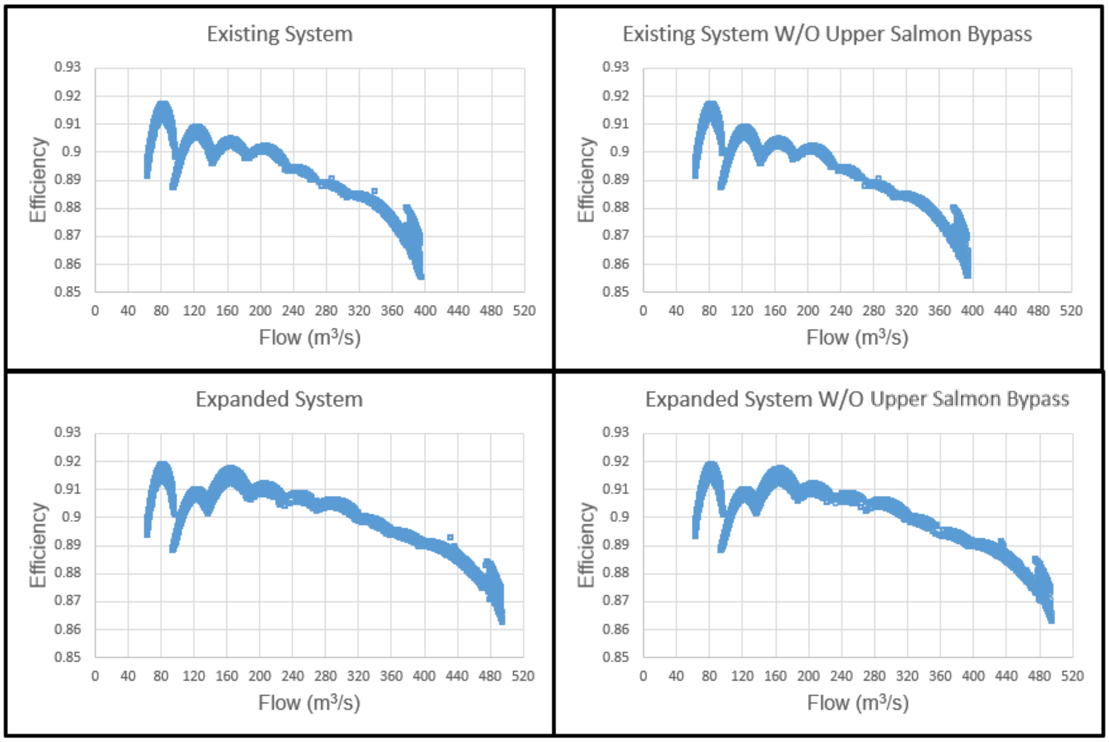

Figure 5-8: Hourly Bay d'Espoir Plant Generation Efficiency with Flow

For the existing system, the most efficient unit (Unit 7) is base loaded, then one of the other six units (which are on combined penstocks) is brought on-line as flow increases, resulting in a plant efficiency drop. This is the first segment of the efficiency duration curve in Figure 5-7. As flow increases further, one unit from the two remaining combined penstocks is brought online, then one unit in the last combined penstock is brought on-line marking the end of the second segment in Figure 5-7. This process causes a gradual decrease in efficiency as tailwater level increases with increasing plant flow. With further increases in flow, the second unit in one of the combined penstocks is brought on-line causing a sharp decrease in efficiency due to higher penstock head loss. The second unit in the two remaining penstocks is brought on-line one after the other with increasing flow until all units are on-line marking the end of the third segment.

The scheduling process for the expanded system follows the same pattern except that the first segment comprises three units. In this case, the most efficient unit (Unit 8) is base loaded, then one of Unit 1 to 6 is brought on-line as flow increases. Unit 7 is then brought on-line as flows increases further, thus completing the first segment. Once Unit 7 is brought on-line, the remaining five units are brought on-line as required (i.e., following the same scheduling process as with the existing system).

All the efficiency curves have a rough cluster near full capacity with the lowest efficiency. This can be explained by examining the monthly box plot of the generation efficiency in Figure 5-9. The low efficiencies typically occur in January to March when load and secondary energy need are higher. This is the drawdown period with varying water level accompanied by higher flows and higher tailwater level. This results in wide variation of head leading to wide variation of efficiency.

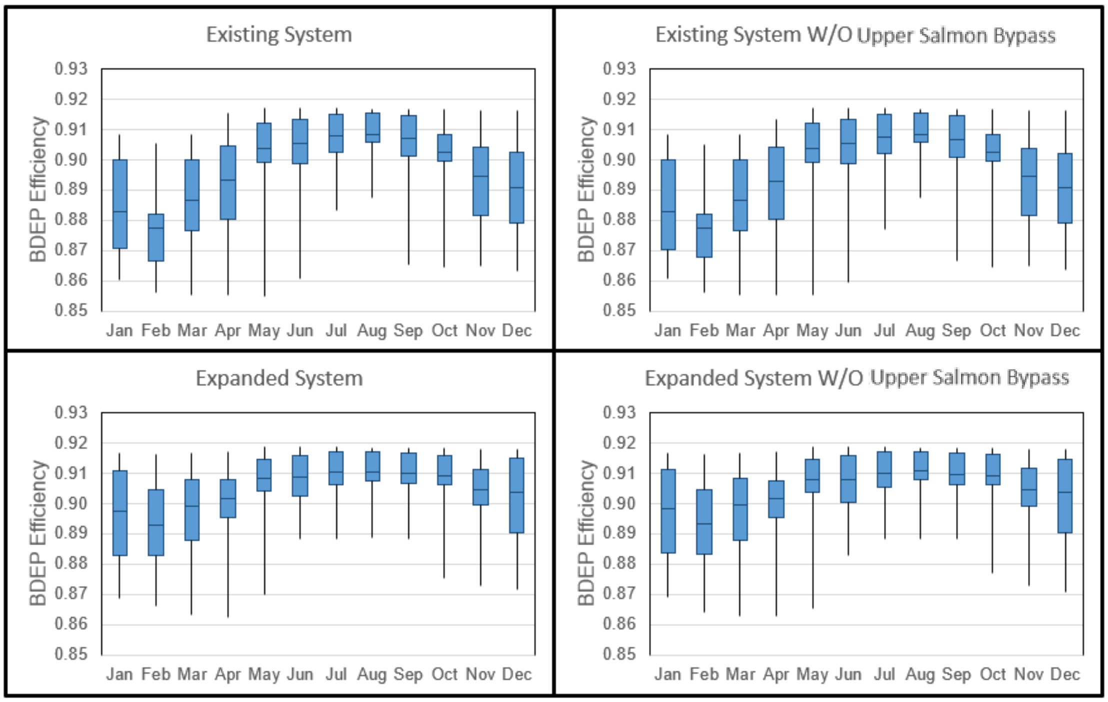

Figure 5-9: Variation in Hourly Bay d'Espoir Plant Generation Efficiency by Month

5.3.5 *Upper Salmon Bypass and West Salmon Spillway Usage*

The Upper Salmon bypass (i.e., North Salmon spillway) is used to pass flows from the Upper Salmon reservoir to Long Pond while bypassing the Upper Salmon plant. According to Hydro, reasons for this may include periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

It was shown in Figure 5-6 that the duration curve of the Bay d'Espoir hourly generation is identical with or without Upper Salmon bypass. This suggests that the bypass is rarely needed to maintain peaking at the plant. So, it is desirable to examine the usage of the bypass and West Salmon spillway.

Figure 5-10 shows duration curves of hourly flows in the North Salmon Spillway and Figure 5-11 shows the duration curves of hourly flows in the West Salmon spillway. The North Salmon spillway is used only 0.6 percent and 1.1 percent of the time for the existing and expanded systems respectively. West Salmon spillway is used only 0.1 percent of the time for both existing and expanded system at very low flow of 5 m^3/s when the North Salmon spillway is available. The spillway is used 3.8 percent and 6.2 percent of the time for the existing and expanded systems respectively without the bypass in the system. There are no spills at Long Pond in any of the scenarios as the capacity driven requirement for generation from Bay d'Espoir is higher than the capacity flow at the Upper Salmon plant.

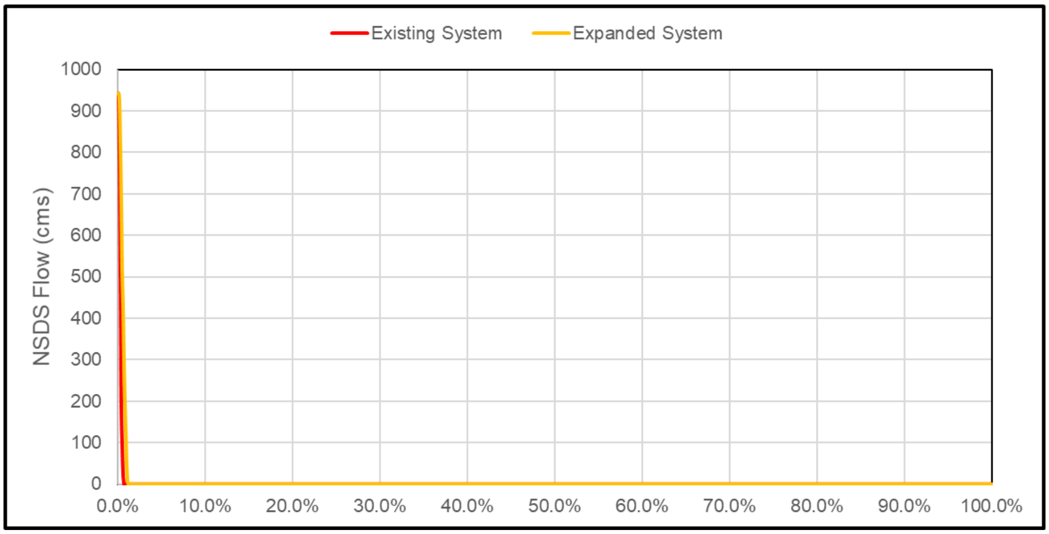

Figure 5-10: Duration Curves of Hourly Flows in the North Salmon Spillway

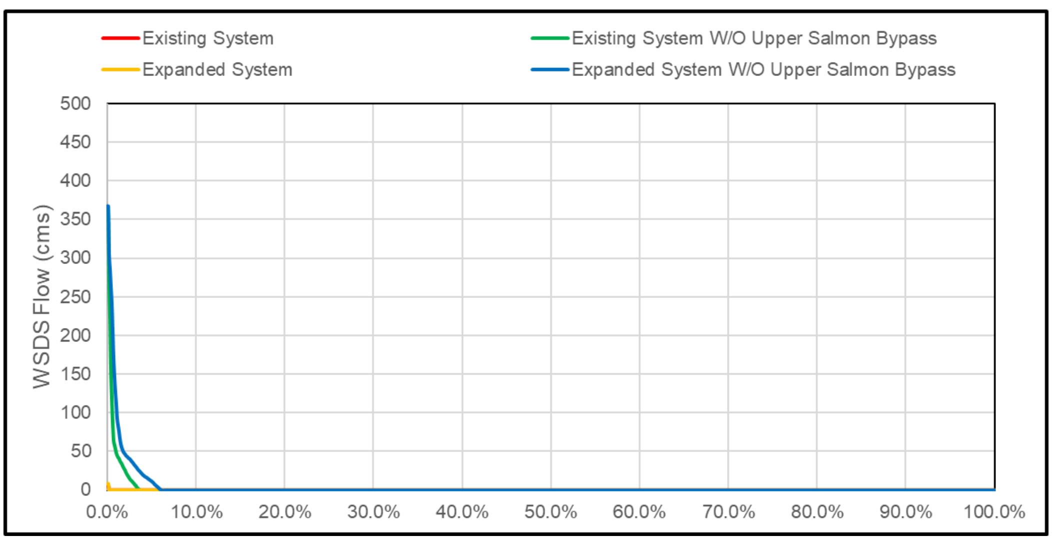

Figure 5-11: Duration Curves of Hourly Flows in the West Salmon Spillway

5.3.6 Impact on the Operation of Upper Salmon Hydroelectric Generating Station

Figure 5-12 shows monthly box plot of the power flow at Upper Salmon. The impact on generation is very subtle and there are slight noticeable differences between the existing and expanded systems operation only in the high load months of January to March. Operations in the rest of the year are quite identical. Comparing the existing and expanded case with the bypass and focusing on the boxes in the box plot, power flows for the expanded case are slightly higher in January to March. In the cases without the bypass, power flows are also higher in the expanded system than the existing system in January to March.

Figure 5-13 shows the duration curves of the hourly generation efficiency at the plant. It can be seen in the figure that, as a result of the January to March increased power flow in the expanded system, the plant is operated slightly less often, 80 percent of the time in the expanded system compared to 81.7 percent of the time in the existing system. There is also loss of efficiency about 2.3 percent of the time in the expanded system compared to the existing system.

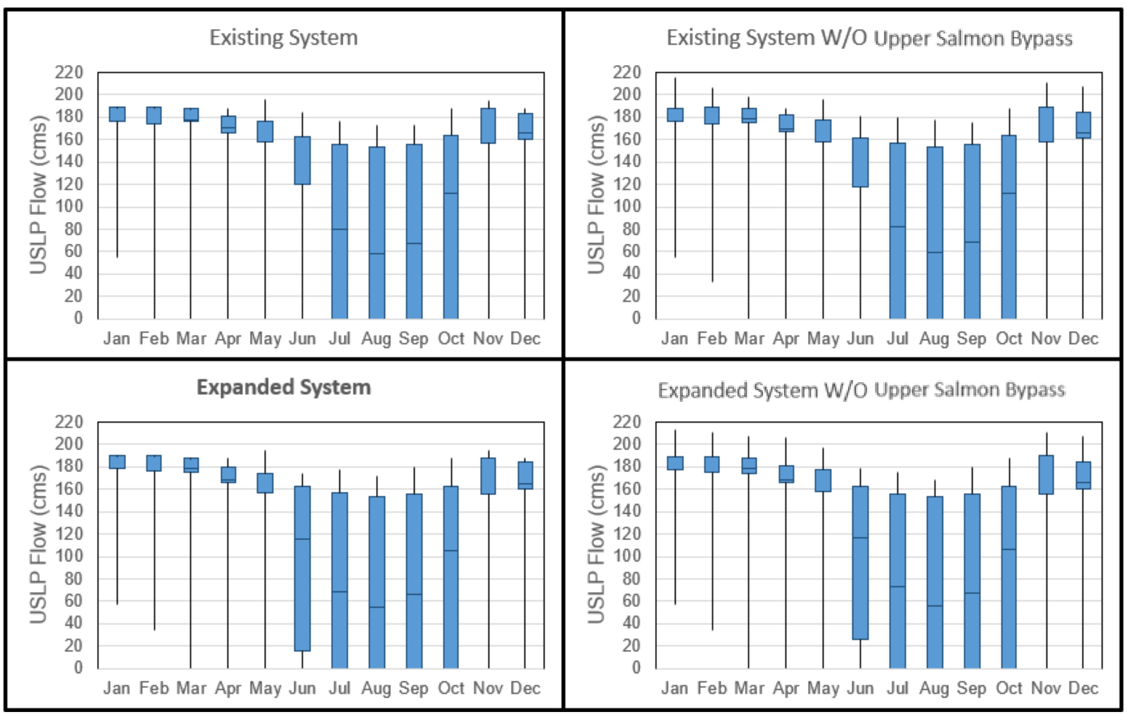

Figure 5-12: Variation in Hourly Upper Salmon Generation Flow by Month

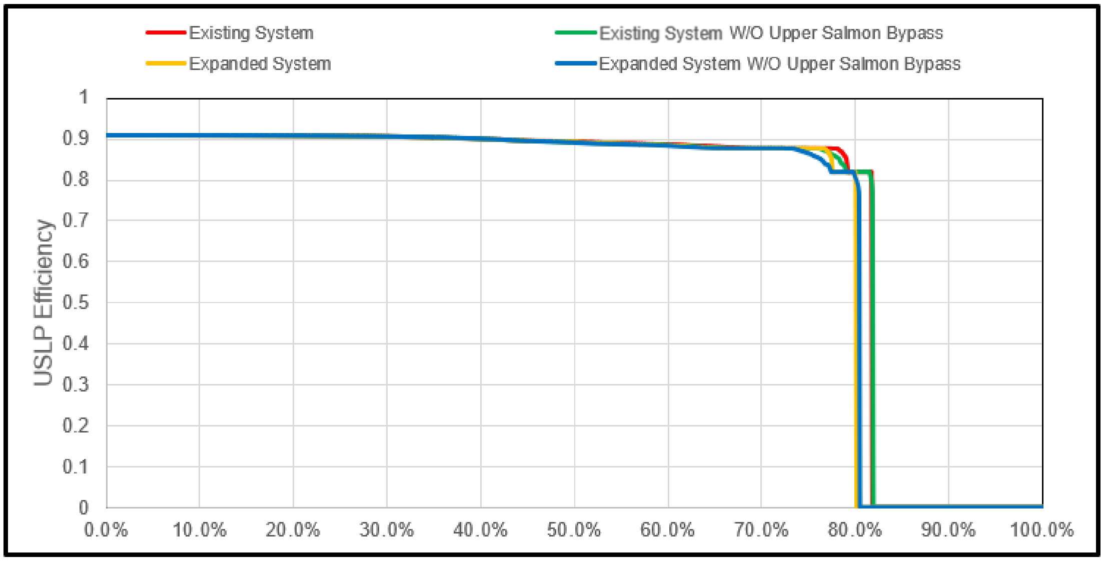

Figure 5-13: Duration Curves of Hourly Generation Efficiency at Upper Salmon Plant

5.3.7 *Recommended Range of Storage of the Bay d'Espoir System Reservoirs in Advance of Winter Operating Season*

The range of simulated monthly end elevations of the three large reservoirs are presented in the following sections. The optimization analysis in this study is for the Bay d'Espoir system alone. Therefore, these elevation ranges are those that maximize the economic benefits of the Bay d'Espoir system generation and not necessarily the overall Nalcor generation system. With this recognition, ranges of end-of-November storage for each reservoir are recommended in this section, to maximize generation in the winter months and allow room for possible early winter high flow. If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter. Hydro should consider further study to examine the impact that lower reservoir levels in advance of winter may have upon generation.

5.3.7.1 *Victoria Reservoir*

Figure 5-14 shows the variation in monthly end elevation of Victoria Reservoir. The elevation ranges and variations are identical across all scenarios. An elevation range of 324.18 m to 325.44 m representing the 25th to the 75th percentiles is recommended at the end of November for Victoria Reservoir.

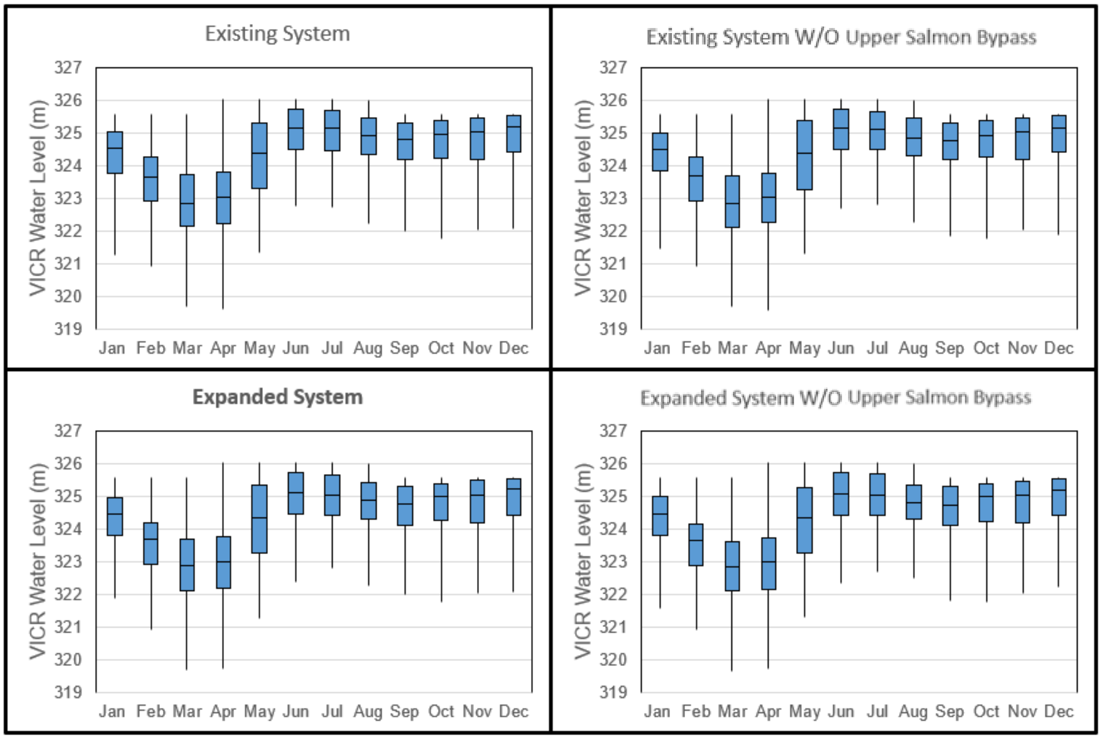

Figure 5-14: Variation in Victoria Reservoir Monthly End Elevation

5.3.7.2 Meelpaeg Reservoir

Figure 5-15 shows the variation in monthly end elevation of Meelpaeg Reservoir. The variation is different in the winter months of January to May for the expanded system. In these months, the 25th to 75th percentiles are both wider and lower for the expanded system than for the existing system. The minimum elevations for the expanded system are also lower in these months. However, the variation and range of elevations in November are identical across all scenarios. An elevation range of 271.46 m to 272.11 m representing the 25th to the 75th percentiles is recommended at the end of November for Meelpaeg Reservoir.

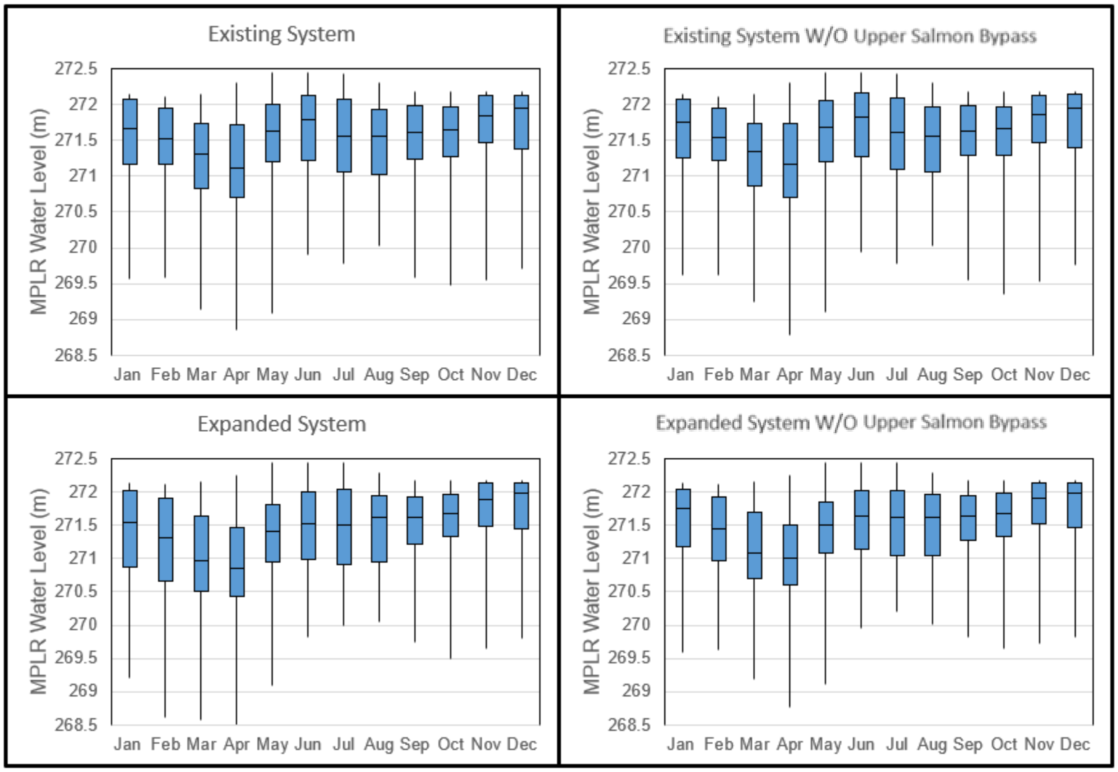

Figure 5-15: Variation in Meelpaeg Reservoir Monthly End Elevation

5.3.7.3 *Long Pond Reservoir*

Figure 5-16 shows the variation in monthly end elevation of Long Pond Reservoir. The elevation ranges and variations are identical across all scenarios from December to May with some differences in the remaining months of the year. The November elevation range is tight. This month has the highest minimum month end elevation in each of the scenarios to provide storage for optimum generation through winter. Therefore, an elevation range of 181.70 m to 182.25 m is recommended at the end of November for the Long Pond Reservoir. 181.70 m is the minimum end of November elevation of the four scenarios and 182.25 m is the 75th percentile of the November end elevation across all scenarios.

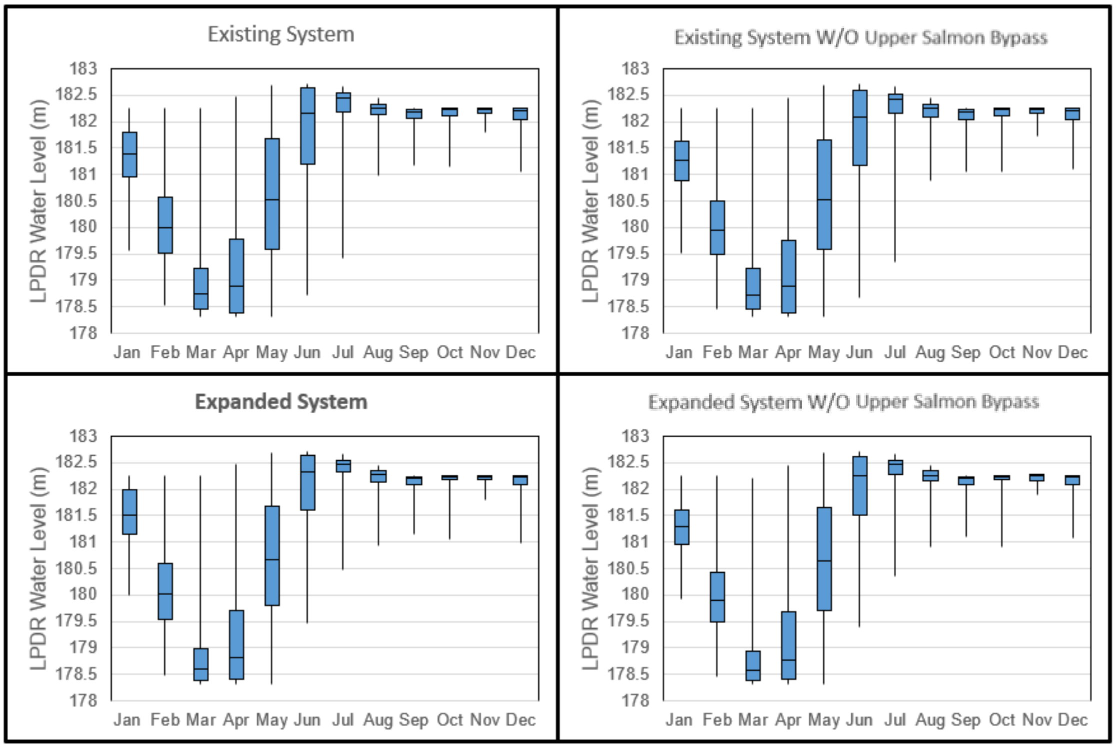

Figure 5-16: Variation in Long Pond Reservoir Monthly End Elevation

6. Conclusions and Recommendations

6.1 Conclusions

The conclusions of the study are as follows.

1. The Hydro inflow series, except for Victoria sub-basin, do not appear to be wholly consistent with the corrected dataset (SGE Acres, 2004). The reason for this is unknown. However, the totals of the Hydro inflows at Upper Salmon and Bay d'Espoir Generating Stations are generally consistent with the corrected dataset and show no significant trend or change; as a result, there should be no adverse impact on the accuracy of the generation estimates at these facilities. The total of the Hydro inflows at Granite Canal Generating Station after 1980 is slightly higher than that of the corrected dataset, but any resulting error in the estimate of total system generation is expected to be small, since Granite Canal accounts for only a small portion of the total system capacity.
2. There is no evidence of significant trend or change in the natural flow series. Any appearance of trend or change in the reference inflow series is therefore expected to be due to inflow calculation methods and does not signify any actual hydrological phenomenon. There are some apparent inconsistencies in the distribution of sub-basin inflows within the system, but these tend to balance each other out.
3. It is concluded that, for the purpose of this study, the Hydro inflow series may be used as provided, for the power and energy analysis of the proposed new Unit 8.
4. The simulated firm energy of the Bay d'Espoir system is 297.0 MWc (with peak load of 541 MW).
5. Addition of Unit 8 to the Bay d'Espoir plant does not impact the firm energy of the Bay d'Espoir system.
6. The simulated average annual energy of the Bay d'Espoir system is 3,394.11 GWh. The simulated average annual energy of the system with addition of Unit 8 to the Bay d'Espoir plant is 3,416.74 GWh, a 0.67 percent increase.
7. The simulated average annual energy of the Bay d'Espoir plant is 2,617.65 GWh. The simulated average annual energy of the plant with addition of Unit 8 is 2,650.64 GWh, an increase of 1.2 percent.
8. With addition of Unit 8, simulated hourly generation of the Bay d'Espoir plant increases 17.6 percent of the time and decreases 29.7 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.
9. With or without addition of Unit 8, the simulated operation of the Bay d'Espoir plant is to generate only to meet firm load 52.7 percent of the time.

10. The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 140.7 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because the model has to meet the defined firm load; the increase in on-peak generation is at the expense of off-peak generation. Although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. Output at full rated capacity of the plant with Unit 8 is possible but would come with a tradeoff in reduced firm and average simulated energy. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.
11. Hatch has not examined the impact of water surface drawdown on adequacy of submergence at power intakes as part of this study. The study assumes that the tailrace improvements recommended by SLI (2018b) are implemented. Otherwise, the information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.
12. With addition of Unit 8, simulated Bay d'Espoir plant efficiency increases are in the range of 0.0016 to 0.0125, with an average of 0.008.
13. The North Salmon bypass spillway is used only 0.6 percent of the time in the simulation of the existing system, and 1.1 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.
14. There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d'Espoir Unit 8. This loss occurred only 2.3 percent of the time.

6.2 Recommendations

The recommendations of the study are as follows.

1. It is recommended to implement the tailrace channel improvement described by SLI (2018b) in order to avoid generation loss when all units at the expanded Bay d'Espoir plant are running.
2. It is recommended that Hydro examine the impact of water surface drawdown on the adequacy of submergence of power intakes, in a separate hydraulic study.

3. The following end-of-November elevation ranges are recommended at the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.

    1. Victoria: 324.18 m to 325.44 m
    2. Meelpaeg: 271.46 m to 272.11 m
    3. Long Pond: 181.70 m to 182.25 m.

    If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter. Hydro should consider further study to examine the impact that lower reservoir levels in advance of winter may have upon generation.

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Appendix A
Hydrological Analysis

A.1 Introduction

The study required a hydrological analysis of the Bay d'Espoir system, including a detailed analysis from 1970 to present and a limited review of the full record. Hydro provided reference inflow series dating back to 1950; the period 1970 to present includes the operational period of the Bay d'Espoir generating station.

The purpose of the analysis was to determine whether there are any trends or anomalies in the sequences, such as continuously increasing or decreasing trends or step trends due to some external factor. A statistical approach was necessary to assess the significance of any apparent finding. The analysis used quantitative statistical tests as well as standard hydrological plotting methods.

A.2 Data Assembly

Reference daily inflow series were provided by Hydro for the period 1950 to 2019 (70 years) for seven sub-basins of the Bay d'Espoir system. The series consisted of daily inflows in each sub-basin area, expressed in m^3/s. The inflows are synthesized or calculated values, not observed data; new inflows are successively appended to each series by backrouting calculations, which make use of recorded turbine flows, spill flows and reservoir levels, and the estimated relationship between reservoir elevation and volume, to solve for the estimated inflows.

For the purpose of this review, the inflows were aggregated into annual values, and converted into volume (million m^3) or equivalent depth of runoff (mm) as necessary to facilitate comparison. There are seven reference inflow series:

- Victoria Lake
- Burnt Pond
- Granite Lake
- Meelpaeg Lake
- Great Burnt Lake
- Cold Spring Pond
- Long Pond

These correspond to the sub-basin drainage areas in Table 2-1 and Figure 2-2.

In addition, records of observed streamflow from selected Water Survey of Canada (WSC) hydrometric stations were analyzed. Streamflows are measured and recorded at WSC hydrometric stations at several locations on the Island of Newfoundland. Three stations were chosen for comparison with Hydro's series, based on sufficient record length and proximity to the Bay d'Espoir system. In general, they are characterized by relatively large drainage areas and long unbroken periods of record and are free from artificial flow regulation. The stations are summarized in and locations are shown in Table A-1 and Figure A-1.

Table A-1: Selected WSC Hydrometric Stations

Name	Station ID	Drainage Area (km^2)
Bay du Nord River at Big Falls	02ZF001	1,170
Gander River at Big Chute	02YQ001	4,450
Lewaseechjeech Brook at Little Grand Lake	02YK002	470

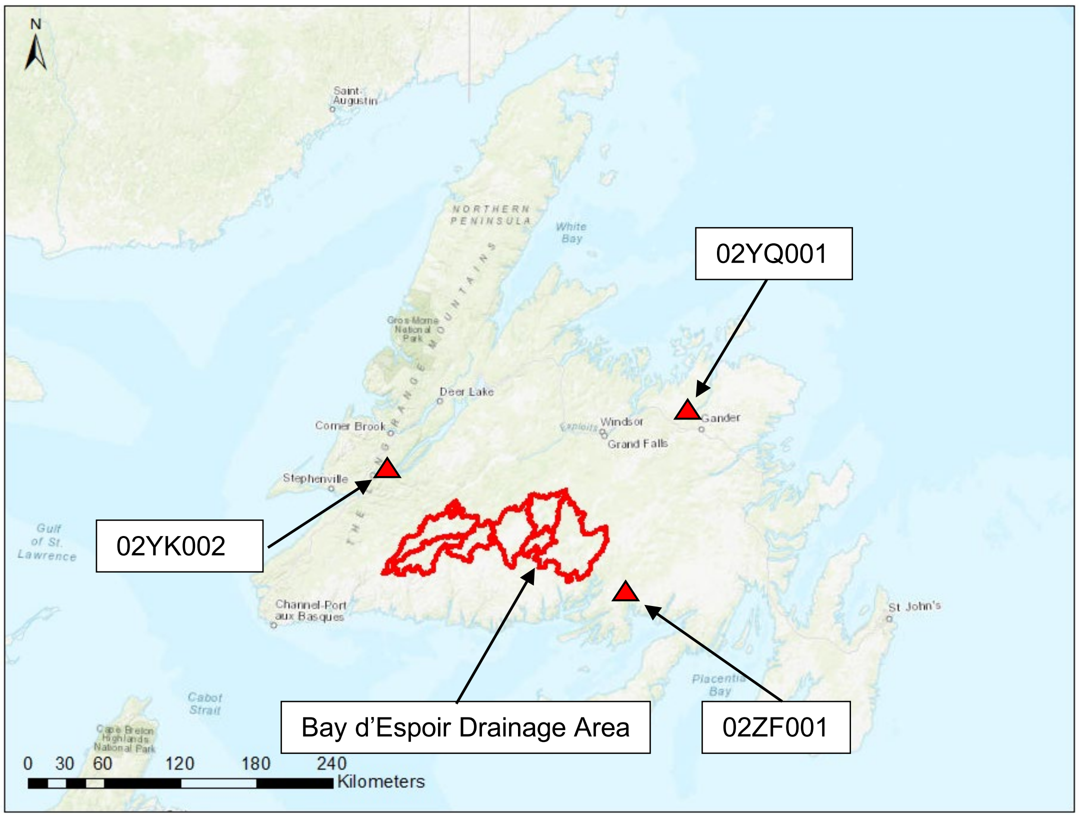

Figure A-1: Selected WSC Hydrometric Station Locations

A.3 Data Analysis Techniques

The purpose of the data analysis was to determine whether there are any trends or anomalies in the series, such as continuously increasing or decreasing trends, or step trends due to some external factor. In the case of the Hydro series, the most likely source of a step trend is the change in methodology for determining inflows after a new generating station within the system came online.

In statistical terms, the purpose of trend analysis is to determine if a series of observations of a random variable is generally increasing or decreasing with time, or whether the probability distribution has changed with time. Two types of trends may be distinguished: step changes, and monotonic trends. Step change tests are for testing changes before and after a known event such as a change in measurement techniques, forest fire, construction of a dam, or diversion. A monotonic trend is one that is continuously increasing or decreasing with time.

If a line is fitted to any time series plot it will almost always show some apparent trend; the chances of a perfectly horizontal line are slim. It is therefore important to carry out the appropriate statistical tests to assess the significance of an apparent trend.

Statistical analysis was done on the flows 1970 to 2019 to analyze a 50 year flow record as per the RFP. The critical p-value adopted for the analysis was 0.05.

A.4 Time Series Plots

Time series plots show the annual average inflow over time. The full series provided by Hydro (1950-2019) were plotted with the remediated inflow series developed by SGE Acres (2004) to verify consistency and continuity. It is noted that SGE Acres (2004) discretized the system inflows into four series: Victoria, Meelpaeg (including Burnt Pond and Granite Lake), Upper Salmon (i.e., Great Burnt Lake and Cold Spring Pond) and Lower Salmon (i.e., Long Pond). To facilitate direct comparison with the current Hydro series, the SGE Acres Meelpaeg and Upper Salmon series have been partitioned into their constituent sub-basins on the basis of drainage area. All series have been expressed as annual volumes (million m^3) as per the format of the original units in SGE Acres (2004).

Figure A-2 to Figure A-8 show the annual inflow volume by sub-basin. It is evident that there are discrepancies involving some of the individual inflow series.

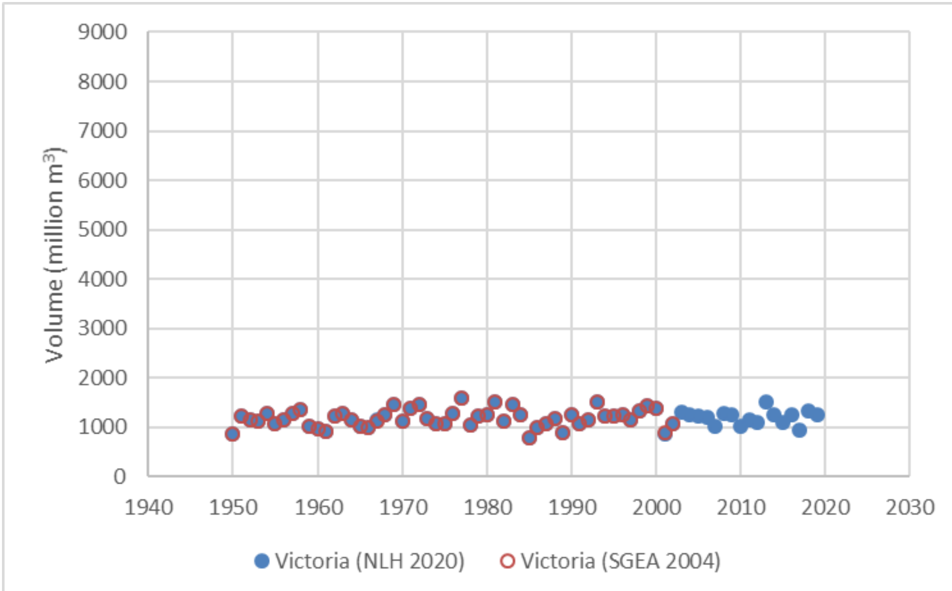

Figure A-2: Victoria Sub-basin Annual Inflow Volume

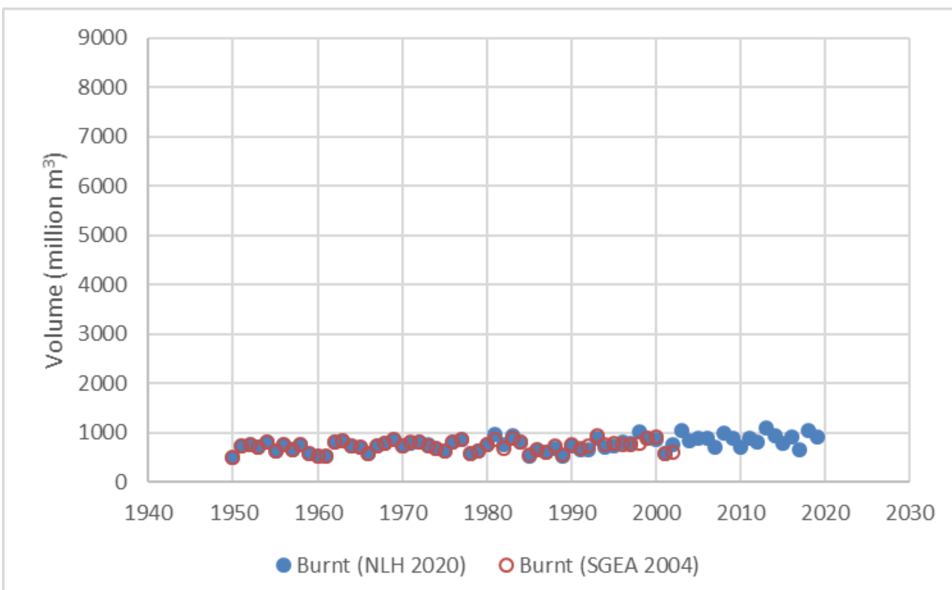

Figure A-3: Burnt Sub-basin Annual Inflow Volume

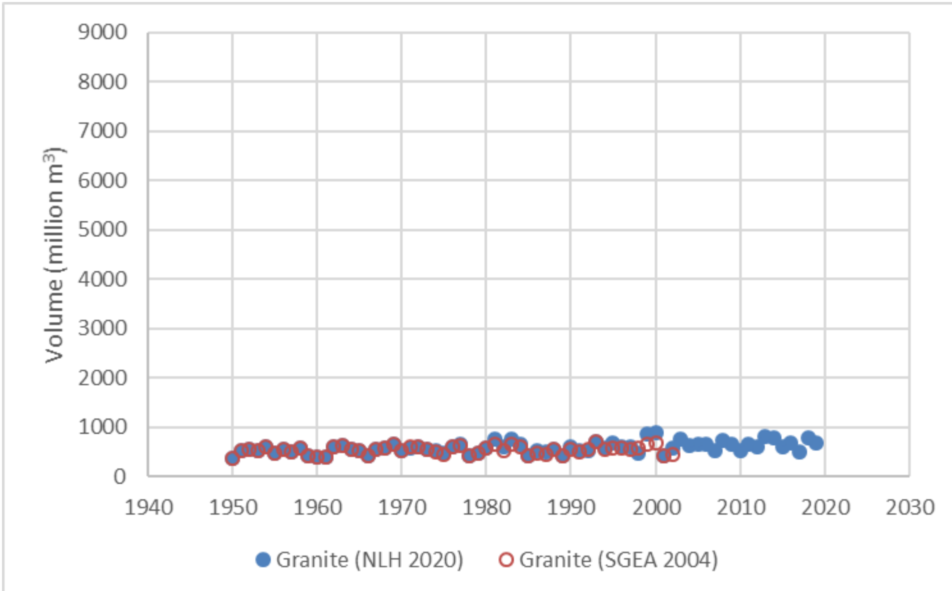

Figure A-4: Granite Sub-basin Annual Inflow Volume

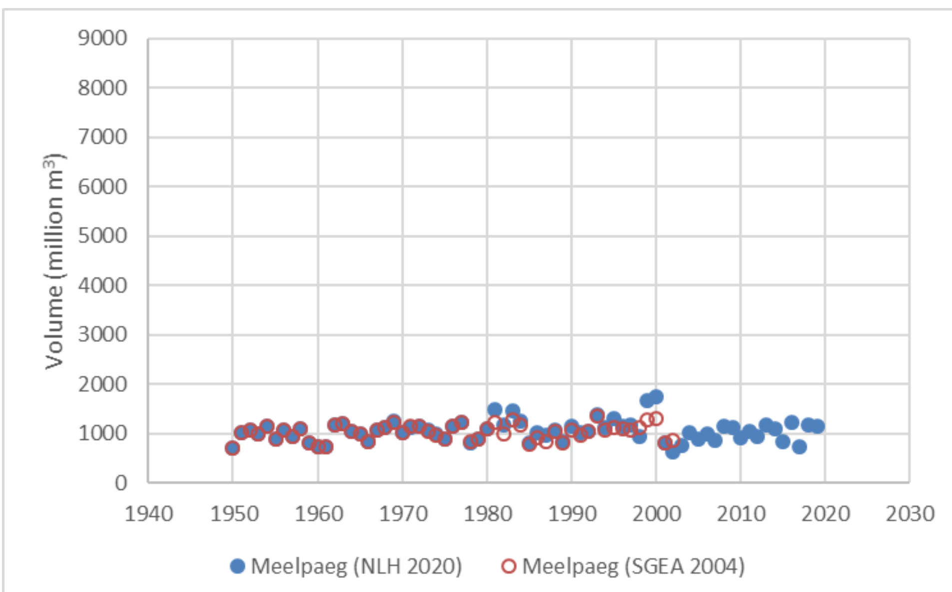

Figure A-5: Meelpaeg Sub-basin Annual Inflow Volume

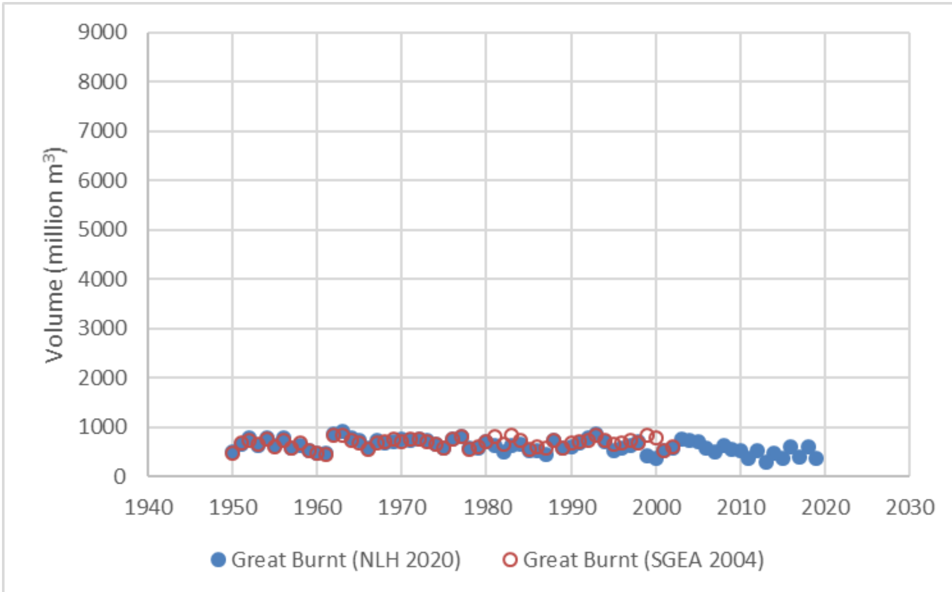

Figure A-6: Great Burnt Sub-basin Annual Inflow Volume

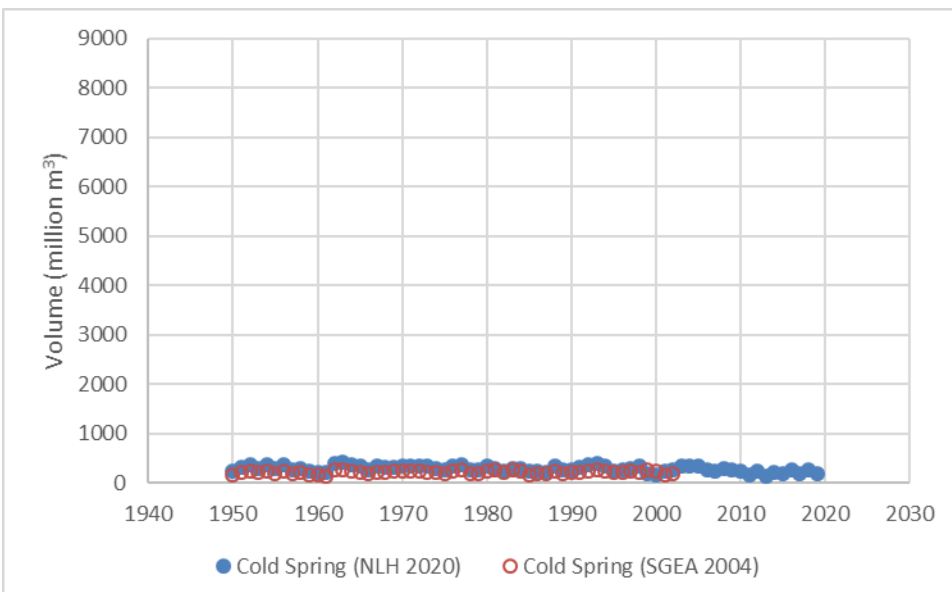

Figure A-7: Cold Spring Sub-basin Annual Inflow Volume

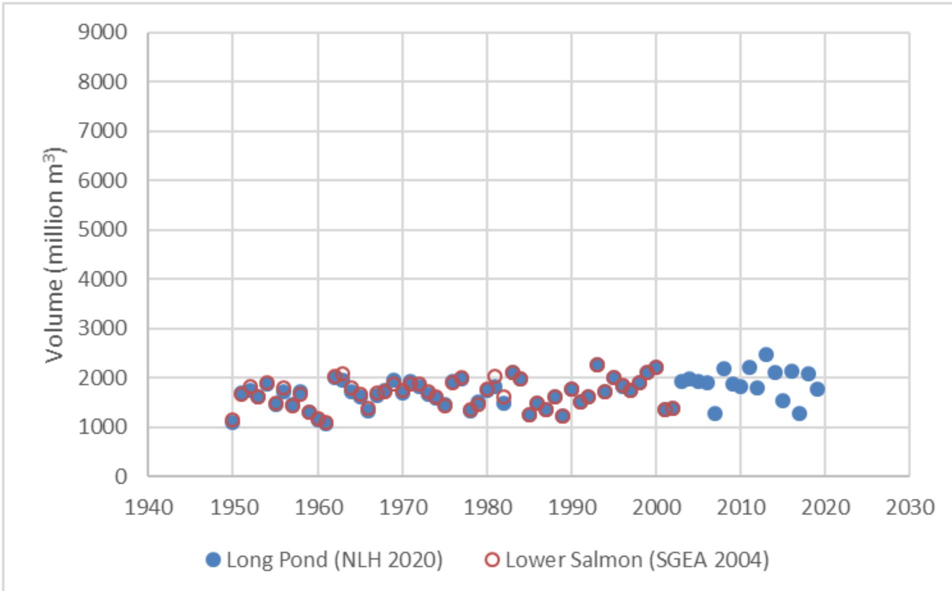

Figure A-8: Long Pond Sub-basin Annual Inflow Volume

- The Victoria inflow series from Hydro is consistent with the previous study (Figure A-2).
- SGE Acres (2004) generated an inflow series called "Meelpaeg" representing the combined Burnt Pond, Granite Lake and Meelpaeg Lake sub-basins. The values from the Hydro series diverge from SGE Acres values after 1980 (Figure A-3, Figure A-4, Figure A-5).
- SGE Acres (2004) generated an inflow series called "Upper Salmon" representing the combined Great Burnt Lake and Cold Spring Pond sub-basins. The values from the Hydro series are not consistent with the SGE Acres values (Figure A-6, Figure A-7).
- The Long Pond inflow series from Hydro has some minor discrepancies but is generally consistent with the previous study (Figure A-8).

The discrepancies above are further discussed in Section A.10, but overall were not considered to be of practical significance to the results of the power and energy analysis in the current study.

Figure A-9, Figure A-10, and Figure A-11 show the total inflow accumulated at each generating station.

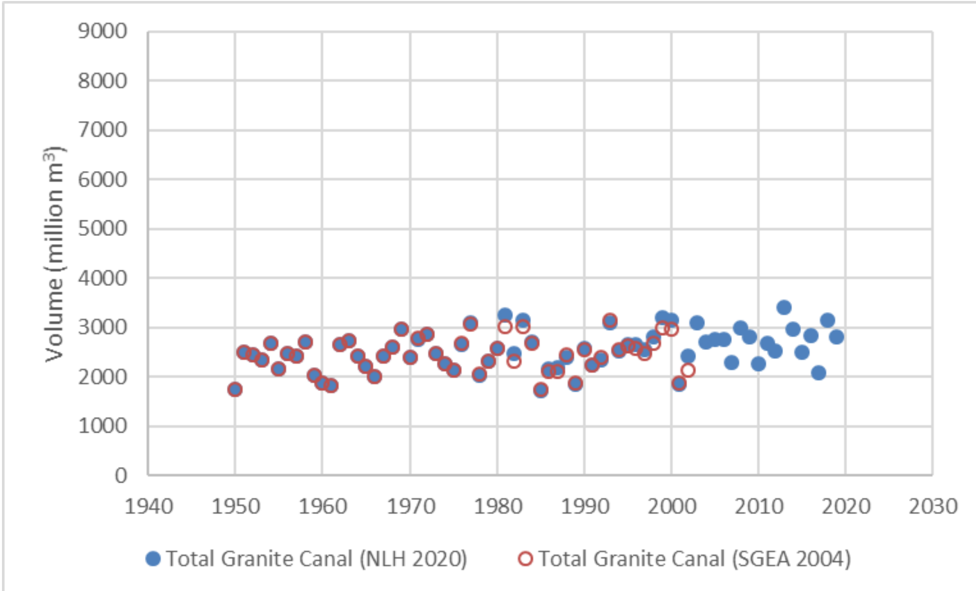

Figure A-9: Total Inflow to Granite Canal GS

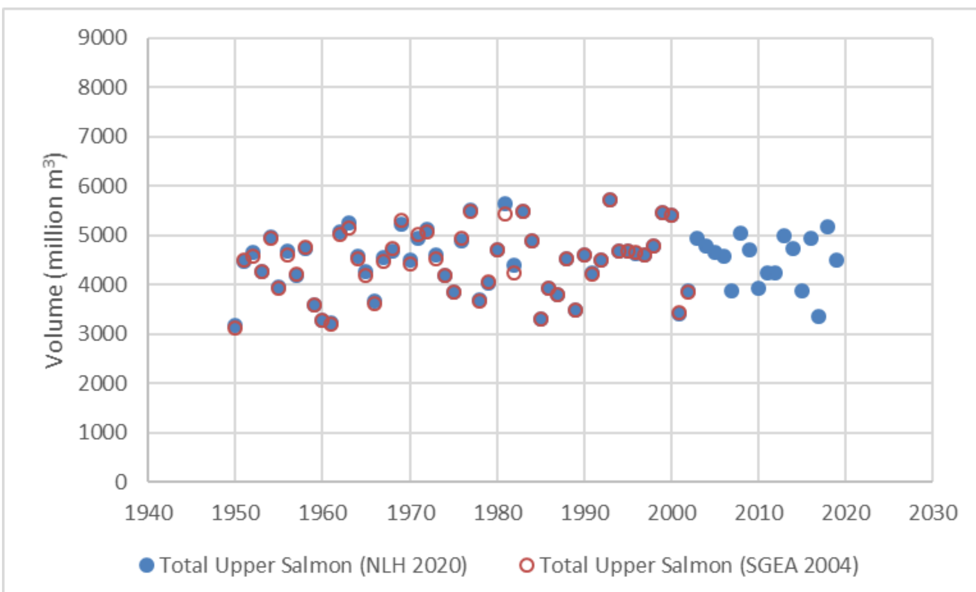

Figure A-10: Total Inflow to Upper Salmon GS

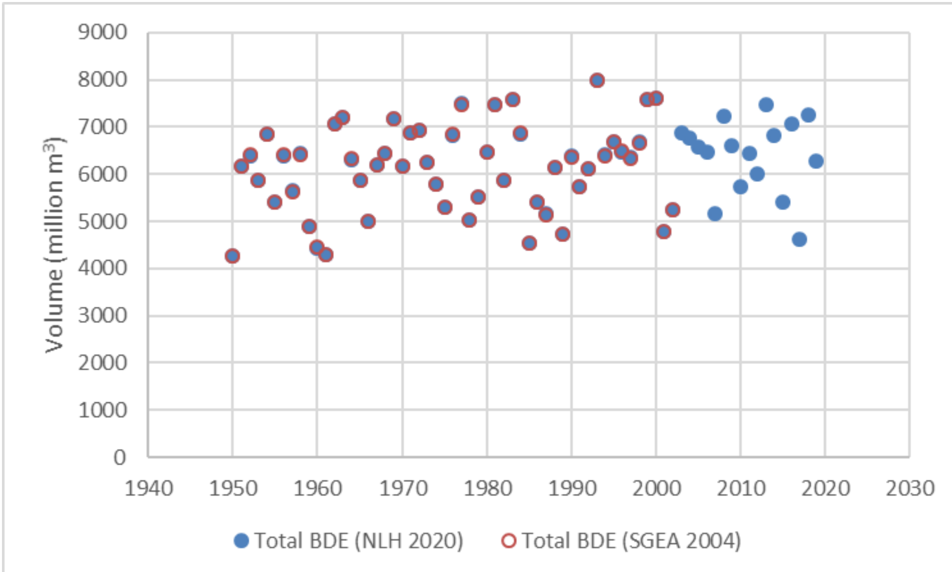

Figure A-11: Total Inflow to Bay d'Espoir GS

- Figure A-11 indicates that the total volume of the Hydro inflow series in the Bay d'Espoir system is consistent with the earlier work of SGE Acres (2004) though some inconsistencies were noted in some of the individual sub-basin inflows.
- Figure A-10 indicates that the total volume of the Hydro inflow series upstream of Upper Salmon is generally consistent with the earlier work of SGE Acres (2004).
- Figure A-9 indicates that the total inflow of the Hydro inflow series upstream of Granite Canal is slightly higher than the SGE Acres series after 1980.

The Hydro reference inflow series were also plotted as mm depth of runoff with Locally Weighted Scatterplot Smoothing (LOESS) lines to smooth the data and visualize dry and wet periods and trends (Figure A-12). An alpha value of 0.33 was chosen to smooth the data and minimize several local minima and maxima.

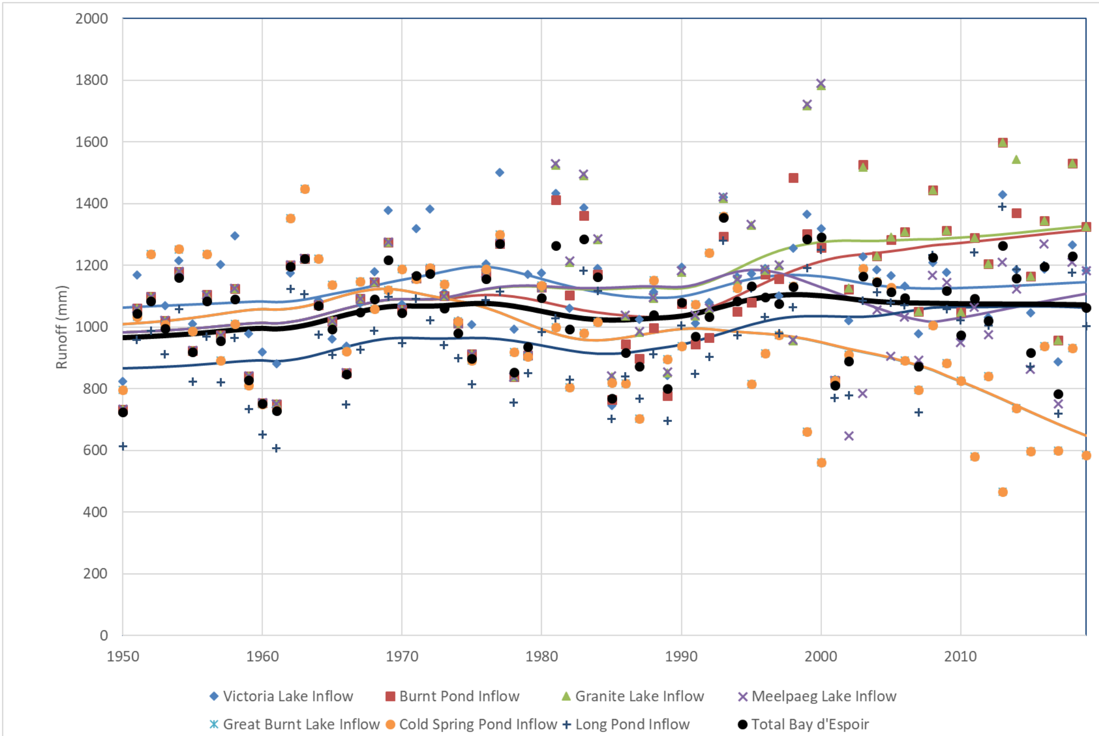

Figure A-12: Sub-basin Inflows with LOESS Lines

From Figure A-12, the following observations are made.

- The Victoria Lake inflow appears to have no notable trend.
- The Burnt Pond inflow matches the Granite Lake and Meelpaeg Lake inflows until 1973, after which it diverges. This suggests that the series were developed from the same hydrological record up to 1973. The Burnt Pond inflow appears to have an overall positive trend.
- The Granite Lake inflow matches the Meelpaeg Lake inflows until 1994, after which it diverges. This suggests that the series were developed from the same hydrological record up to 1994. The Granite Lake inflow appears to have an overall positive trend.
- The Meelpaeg Lake inflow appears to have no notable trend.
- The Great Burnt and Cold Spring Pond inflows match each other. This suggests that they are developed from the same hydrological record. They appear to have an overall negative trend.
- The Long Pond inflow appears to have a slight positive trend, more so in the latter half of the series.
- The total Bay d'Espoir inflow appears to have no notable trend.

Figure A-13 shows the same inflows but accumulated upstream of each generating station.

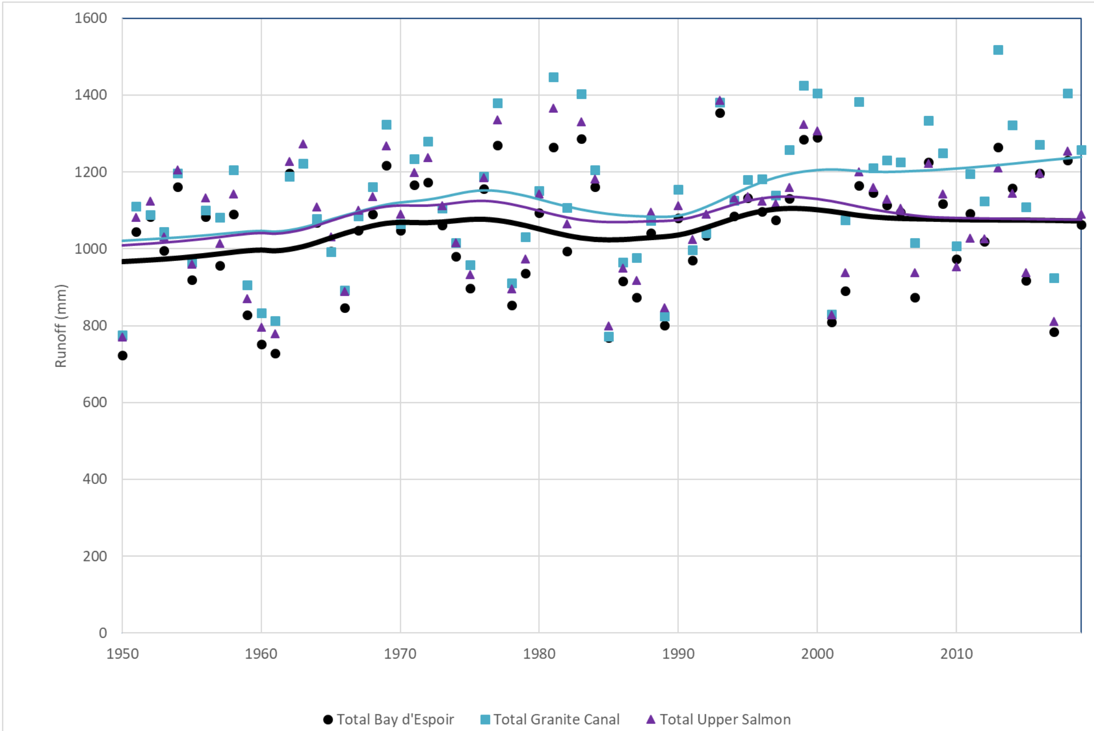

Figure A-13: Total Generating Station Inflows with LOESS Lines

As noted previously, total inflow to Bay d'Espoir appears to have no notable trend. The same may be said of total inflow to Upper Salmon. However, total inflow to Granite Canal appears to be higher than expected in the latter part of the record.

The WSC observed streamflow series are plotted as mm depth of runoff with LOESS lines to smooth the data and visualize dry and wet periods and trends (Figure A-14). The records appear to have no notable trend at least since 1970.

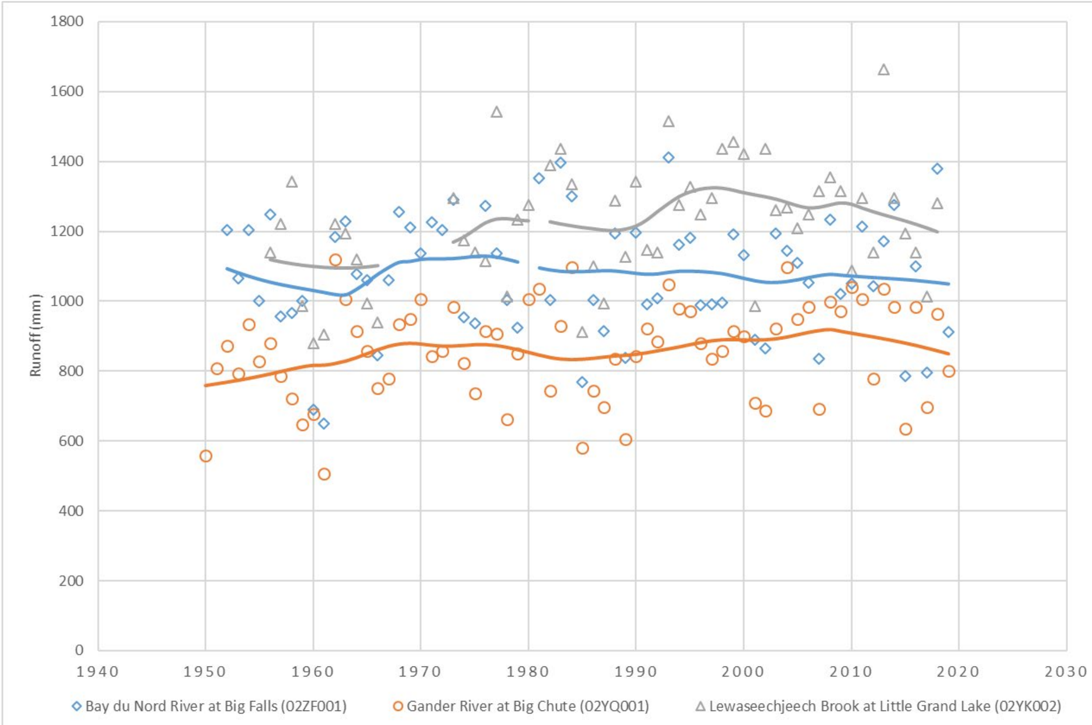

Figure A-14: Time Series of WSC Hydrometric Stations with LOESS Lines

A.5 Normality Tests

The Shapiro-Wilk test (Shapiro and Wilk, 1965) was used as a quantitative test to determine if the inflows (1970-2019) were normally distributed. A p-value greater than critical indicated that the data was normally distributed. If the data are not normally distributed, then parametric tests cannot be used. The p-values were greater than 0.05 for all inflow records with the exception of Meelpaeg Lake. The normal probability plot of Meelpaeg is shown in Figure A-15; non-normality is evident from two apparent high outlier values well off the line of best fit, corresponding to years 1999 and 2000.

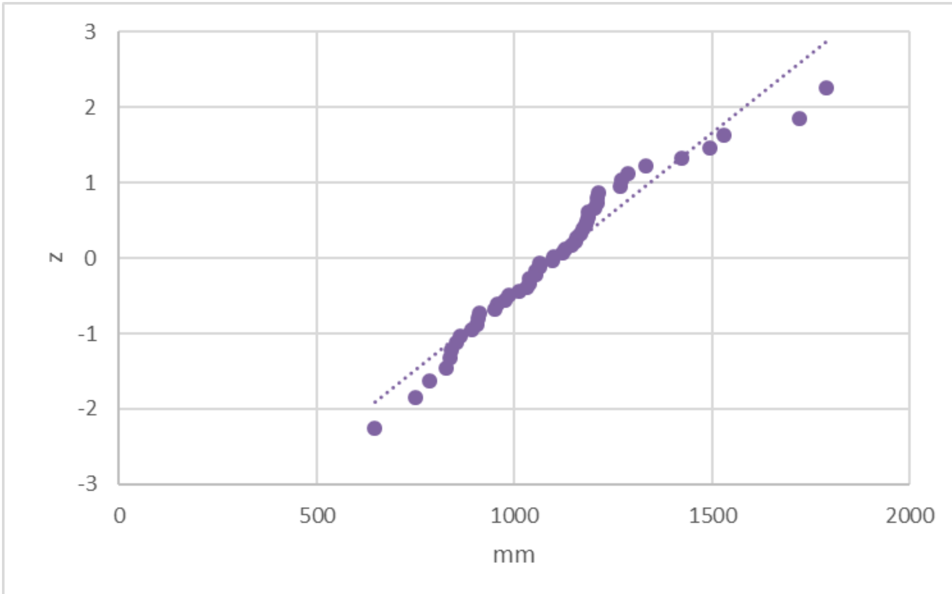

Figure A-15: Meelpaeg Normal Probability Plot

Based on these results, parametric tests were used in all sub-basins except Meelpaeg Lake, where only non-parametric tests were used.

A.6 Monotonic Trend Tests

The non-parametric Mann-Kendall trend test (Mann, 1945; Kendall, 1975) is commonly used to analyze trends in hydrological time series. It is based on the correlation between the ranks of a time series and their time order and tests the null hypothesis that there is no change in the median of the independent observations over time. The main reason for using non-parametric tests is that their power and significance are not affected by the actual distribution of the data. Parametric tests such as the regression coefficient test assume that the data are normally distributed, and their power can be greatly weakened when this assumption is not satisfied. Non-normally distributed data are very common for hydrological time series, and the insensitivity to distribution makes the use of non-parametric tests preferable (Kundzewicz and Robson, 2000; Yue et al., 2002). At the same time, non-parametric procedures are only slightly less powerful that parametric tests when used on normally distributed data. Moreover, they avoid the effort and the potential for real or perceived biases being imparted by the data analyst (Hirsch et al., 1991).

The assumption of serial independence of a time series is still required for the resulting p-values of the Mann-Kendall test to be correct (Helsel and Hirsch, 2002). The reason is that, if autocorrelation (persistence) is present, the test may indicate a significant trend in a time series which is actually random, more often than the significance level specifies. In several studies, this problem has been approached by first testing the time series for lag-1 autocorrelation, and if the autocorrelation coefficient is significant or above a certain threshold, a "pre-whitening" procedure is applied to the data series remove the effect of the serial dependence before carrying out the Mann-Kendall test. However, Fleming and Clarke (2002) concluded that pre-whitening of annual hydrologic time series can substantially and inappropriately reduce the power of trend significance tests and increase slope estimate errors. They recommended that pre-whitening not be applied to annual hydrologic time series unless there is a strong site-specific physical basis for the assumption of lag-1 autocorrelation.

There is no physical basis to presuppose that natural runoff in the Bay d'Espoir watershed is serially dependent on an annual scale; therefore, the Mann-Kendall test was conducted on all the data series without adjustment. Parametric linear regression was also carried out for all Hydro sub-basins that were identified to be normally distributed (i.e., all except Meelpaeg). The results of the monotonic trend tests were classified into five categories from Burn (1997):

- Category 1 is a statistically significant increasing trend with p-values less than 0.05.
- Category 2 is a mild increasing trend with p-values between 0.05 and 0.10.
- Category 3 is a weak trend or no trend. P-values are greater than 0.10.
- Category 4 is a mild decreasing trend with p-values between 0.05 and 0.10.
- Category 5 is a statistically significant decreasing trend with p-values less than 0.05.

Regression results agreed with the Mann-Kendall test results with only a slight difference in the p-values. The classifications of the flow series based on the p-value were as follows.

- Victoria Lake was classified as Category 3, indicating a weak or no trend.
- Burnt Pond was classified as Category 1, indicating statistically significant increasing trend.
- Granite Lake was classified as Category 1, indicating statistically significant increasing trend.
- Meelpaeg Lake was classified as Category 3, indicating a weak or no trend.
- Great Burnt Lake was classified as Category 5, indicating statistically significant decreasing trend.
- Cold Spring Pond was classified as Category 5, indicating statistically significant decreasing trend.
- Long Pond was classified as Category 2, indicating mild but not statistically significant increasing trend.

- The total Bay d'Espoir inflow series was classified as Category 3, indicating a weak or no trend.
- All of the WSC streamflow records were classified as Category 3, indicating a weak or no trend.

These trends can be observed in the time series plots, Figure A-12. Despite the appearance of significant trend in some of the Hydro series, no significant trends were found in the independent WSC records of observed streamflow in other rivers, or in the total inflow to the system. It is unusual that the trends in the sub-basin inflows are in different directions. If the actual annual inflows in the Bay d'Espoir system experienced any trends, we would expect to see such trends reflected in regional streamflow measurements, and to see a consistent overall pattern in the trends. The evidence does not support the presence of trends in the actual annual inflows to the Bay d'Espoir system. It is concluded that the appearances of trends in the Hydro series are due to internal inconsistencies in the calculations of inflows over the period of record, rather than any actual hydrological phenomenon.

An apparent monotonic trend can mask a step change and so it is necessary to consider step change tests and mass curve analysis as described in the following sections.

A.7 Step Change Tests

Step change analysis was carried out on the inflow data before and after points of suspected intervention. During the period of record after 1970, two generating stations came online: Upper Salmon in 1983, and Granite Canal in 2003. These were assumed to be potential change points that could have affected the calculations of inflow. Step change analysis was done twice, breaking the time series into periods before and after the date of suspected intervention to determine if there was an effect. The streamflows from the WSC hydrometric stations were also tested to see if any step changes also occurred in the natural rivers.

The standard tests include the Mann-Whitney test (Mann and Whitney, 1947) and the t-test, both of which assume that the time of change is known. The Mann-Whitney test is a non-parametric (rank-based) test that looks for differences between two independent sample groups. Its parametric counterpart is the t-test, which requires that the data be normally distributed and therefore could not be used for the Meelpaeg series. Both tests produced the same conclusions for all series.

- Victoria Lake showed no significant step changes.
- Burnt Pond showed a positive step change when subdivided by 1970-1982 and 1983-2019.
- Granite Lake showed a positive step change when subdivided by 1970-1982 and 1983-2019.
- Meelpaeg Lake showed no significant step changes.

- Great Burnt Lake showed a negative step change when subdivided by 1970-1982 and 1983-2019, and also when subdivided by 1970-2002 and 2003-2019.
- Cold Spring Pond showed a negative step change when subdivided by 1970-1982 and 1983-2019, and also when subdivided by 1970-2002 and 2003-2019.
- Long Pond showed a positive step change when subdivided by 1970-2002 and 2003-2019.
- The total Bay d'Espoir inflow showed no significant step changes.
- None of the WSC streamflow records showed significant step changes.

Despite the appearance of significant step changes in some of the Hydro series, no significant step changes were found in the independent WSC records of observed streamflow in other rivers, or in the total inflow to the system. It is unusual that the step changes in the sub-basin inflows are in different directions. If the actual annual runoff in the Bay d'Espoir system experienced any step changes, we would expect to see such step changes reflected in regional streamflow measurements, and to see a consistent overall pattern in the step changes. The evidence does not support the presence of step changes in the actual annual inflows to the Bay d'Espoir system. It is concluded that the appearances of step changes in the Hydro series are due to internal inconsistencies in the calculations of inflows over the period of record, rather than any actual hydrological phenomenon.

A.8 Runs Test

The runs test was used to confirm general randomness of the annual flows. A run is a continuous set of values above or below the median concurrently. Runs analysis is a time series analysis tool that indicates whether there are unusually large or small numbers of runs, and whether any of them lasted an unusual length of time. The distribution of run lengths also provides an indication of the volatility of the series; if there are frequent changes in runs above and below the mean or median then the series is considered volatile. Too many or too few runs indicate that there may be a problem with randomness of the data. A normal pattern for hydrological time series is one of randomness.

Runs analysis found the resulting p-value for all series to be greater than 0.05, and thus all of the series were considered to be random.

A.9 Mass Curve Analysis

A mass curve analysis is a standard hydrological plotting technique to aid in detection of changes in the homogeneity or consistency of the data. A single mass curve is a plot of cumulative flows against time. A record that is homogeneous and consistent will plot as a straight line. Any change in the consistency or homogeneity of the data record will show up as a change in the slope of the mass curve. A double mass curve is a plot of cumulative flows against the cumulative flows of another station that is known to be consistent (e.g., a nearby hydrometric gauge). Again, a change in slope indicates that the data set is internally inconsistent.

Figure A-16 shows the single mass curves for the three WSC hydrometric stations. The curves appear to be reasonable in that each maintains essentially the same overall slope throughout the record. The slopes are indicative of the wetness of each basin; Gander River is in the relatively drier northeast of the Island and has a milder slope. Slight changes in slope are indicative of wetter and drier periods during the record. Bay du Nord and Lewaseechjeech each have one missing year of data in the early 1980s which is responsible for a slight offset in the respective curves.

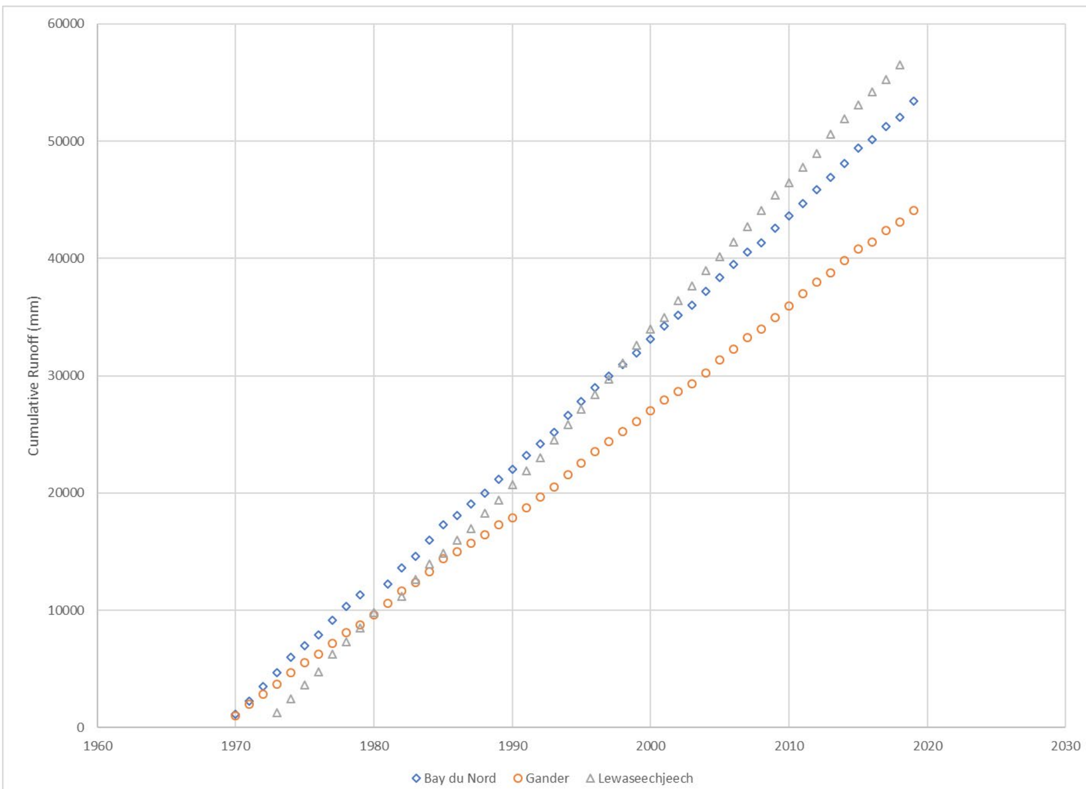

Figure A-16: Single Mass Curve: WSC Hydrometric Stations

As in (SGE Acres, 2003), Gander River was selected as a basis for comparison due to its continuous long term record. Figure A-17 shows the double mass curves of the Bay d'Espoir inflow series with Gander River as the common reference.

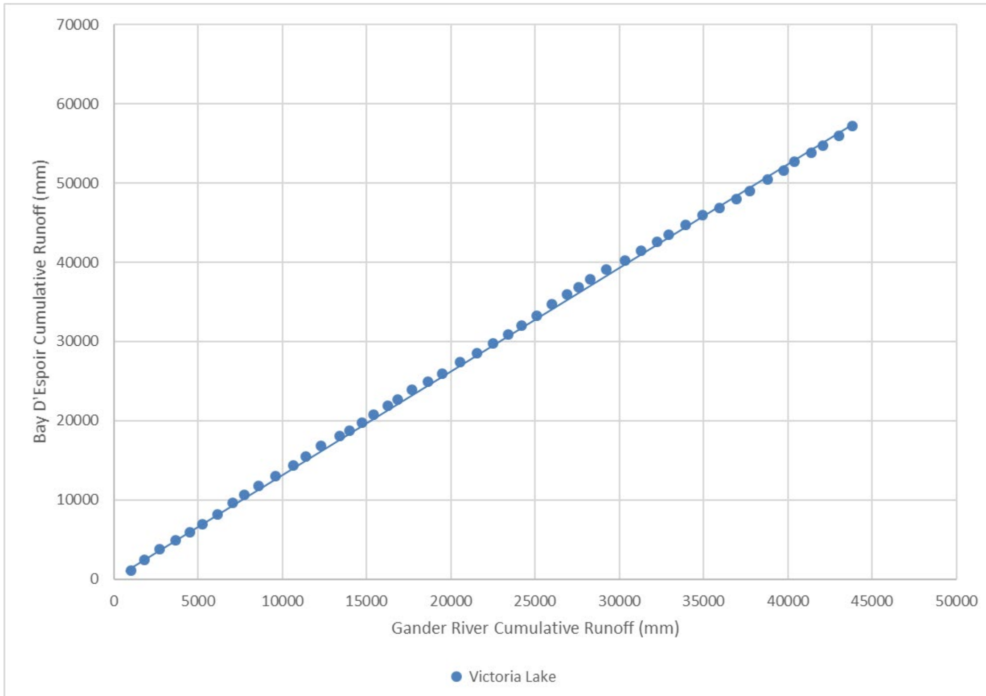

Figure A-17: Double Mass Curve: Victoria Lake

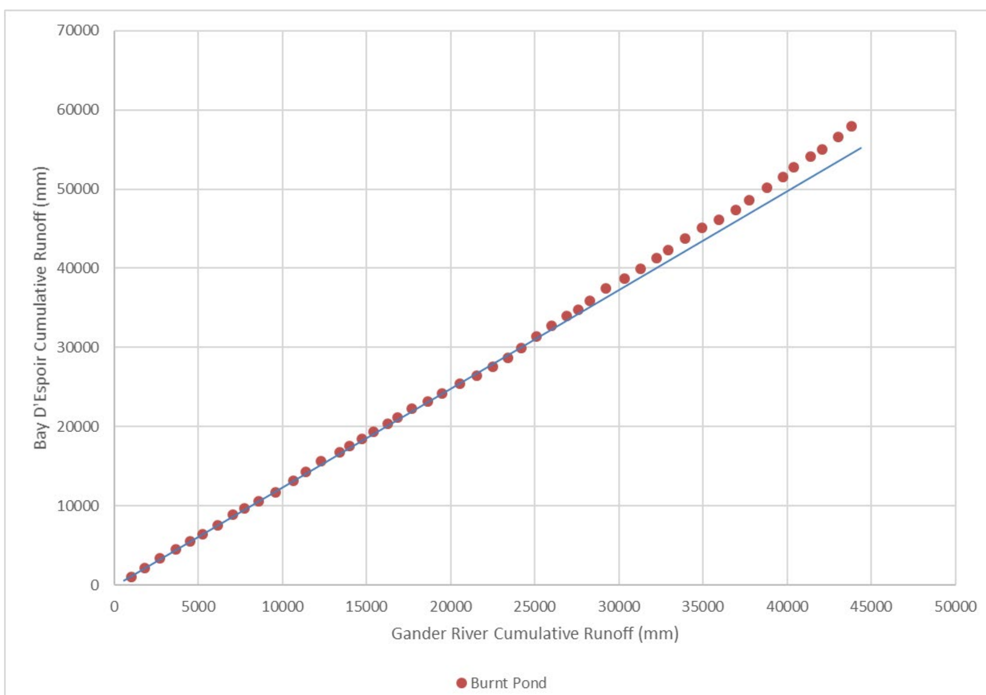

Figure A-18: Double Mass Curve: Burnt Pond

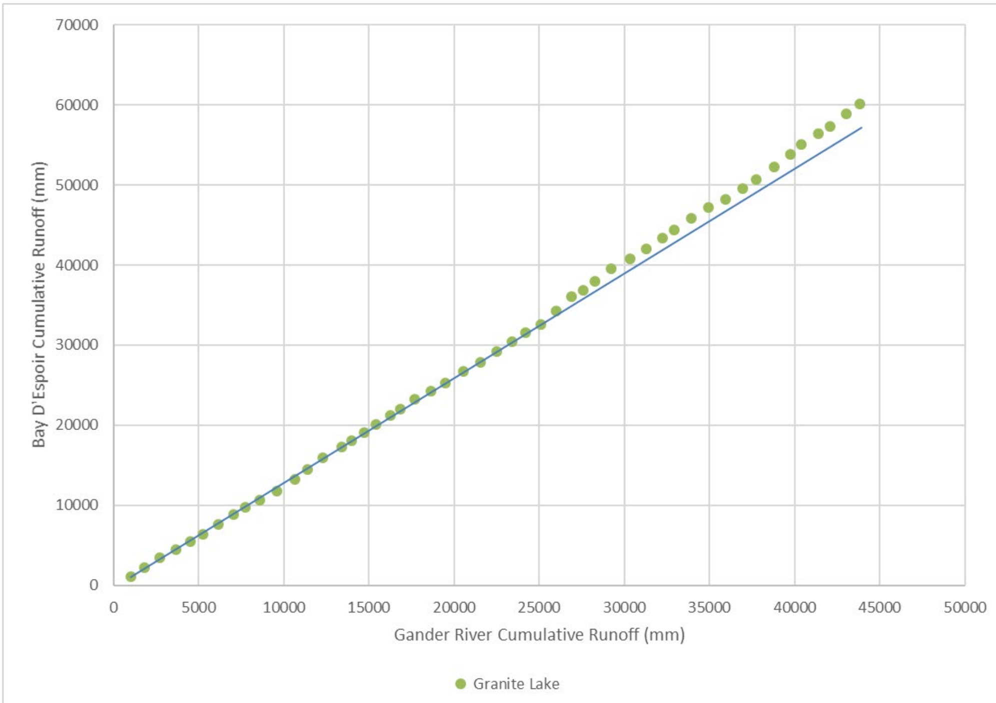

Figure A-19: Double Mass Curve: Granite Lake

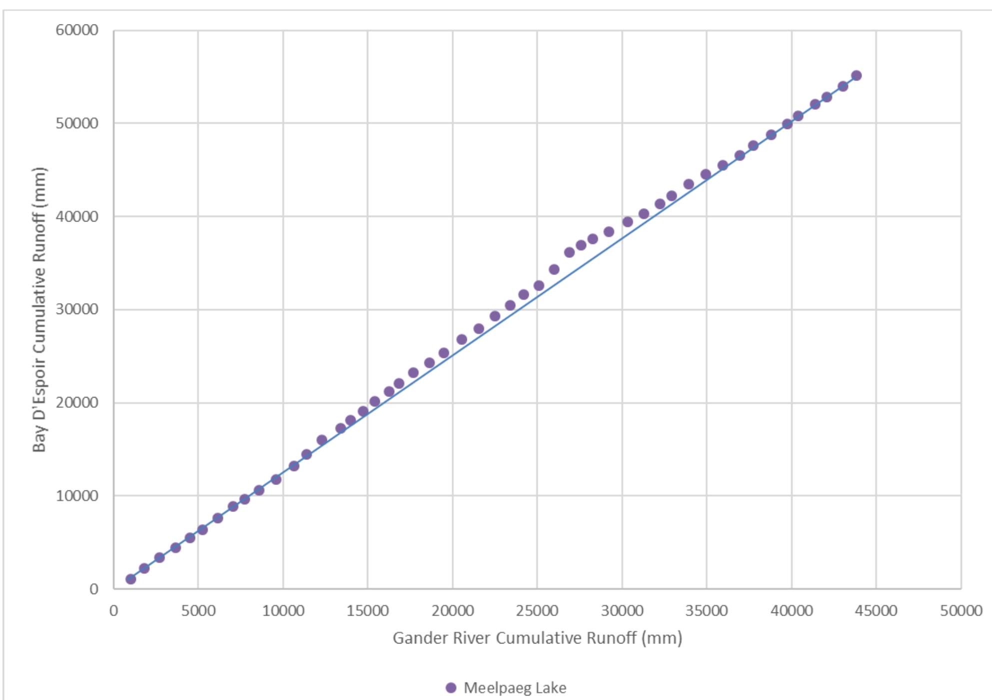

Figure A-20: Double Mass Curve: Meelpaeg Lake

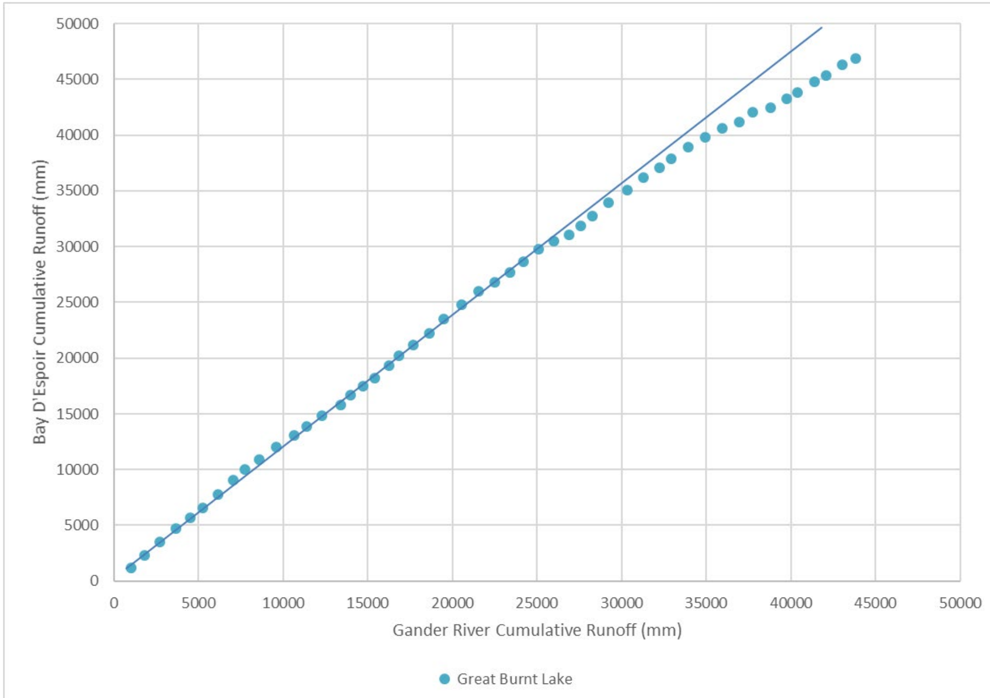

Figure A-21: Double Mass Curve: Great Burnt Lake

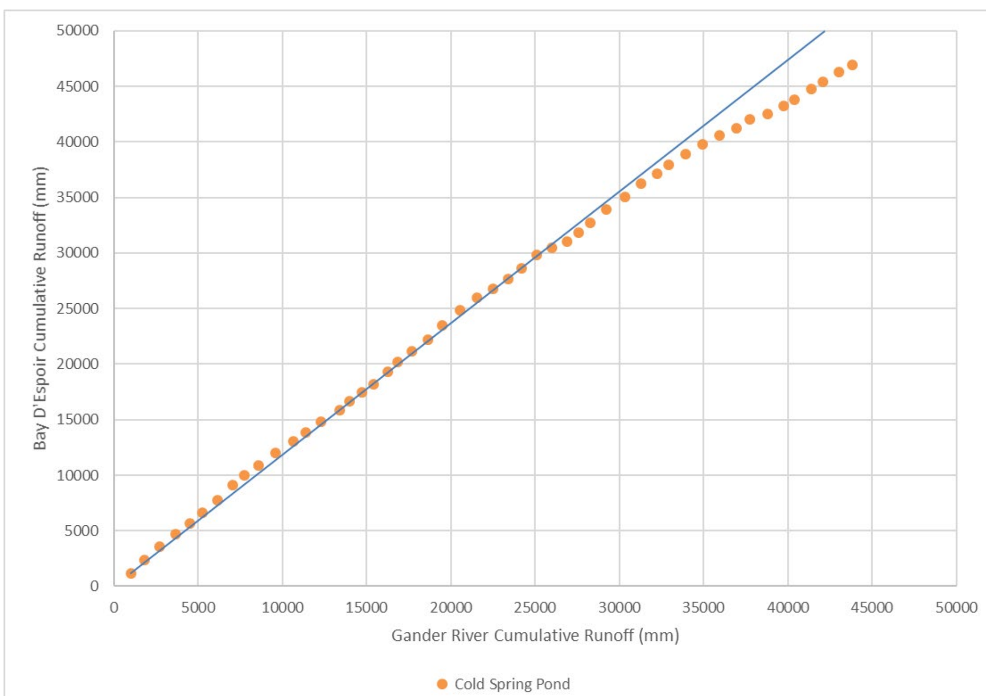

Figure A-22: Double Mass Curve: Cold Spring Pond

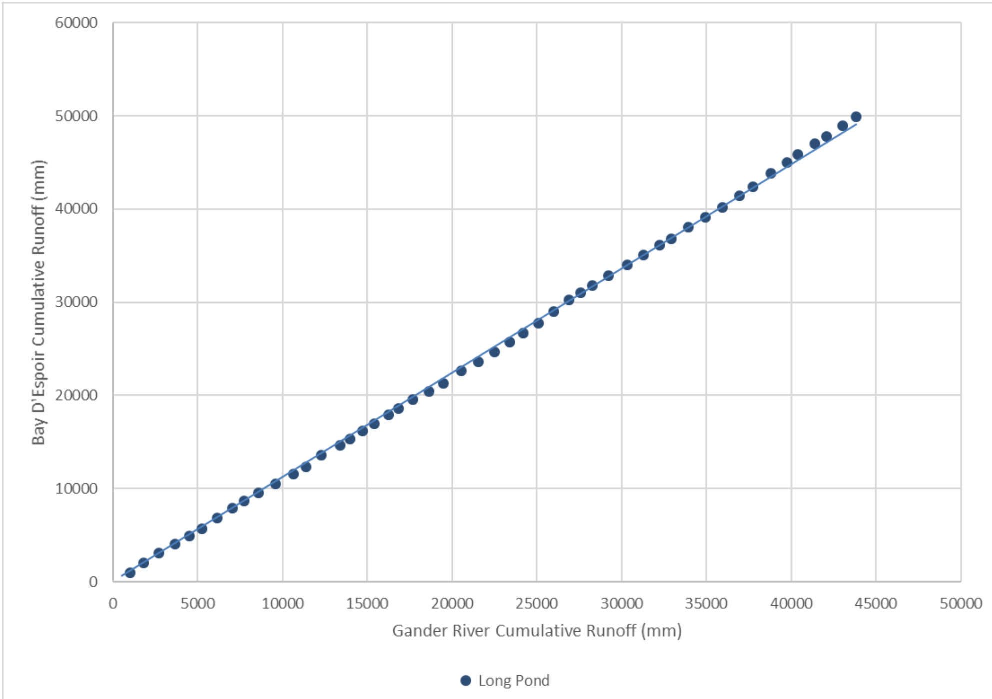

Figure A-23: Double Mass Curve: Long Pond

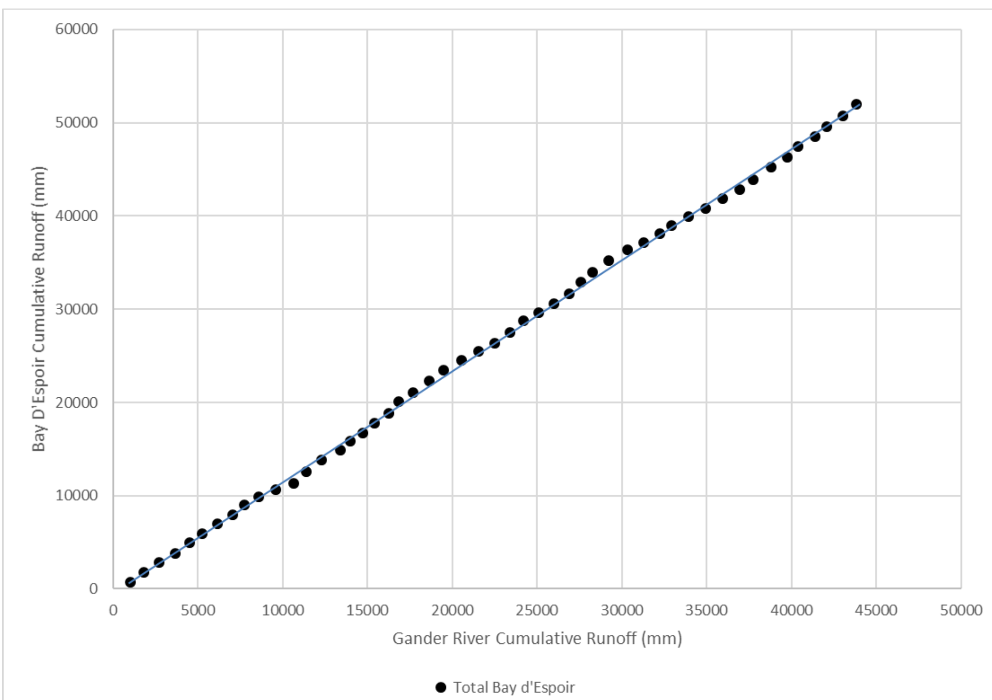

Figure A-24: Double Mass Curve: Total Bay d'Espoir

- Victoria shows no internal inconsistencies.
- Burnt Pond and Granite Lake both show increased slope in the latter portion of the time period, consistent with the findings of the step change analysis.
- Meelpaeg has consistent overall slope but a slight break in the curve that distinguishes the two years of data (1999, 2000) identified previously as apparent outliers.
- Great Burnt and Cold Spring both show diminished slope in the latter portion of the time period, consistent with the findings of the step change analysis.
- Long Pond shows no internal inconsistencies.
- Total Bay d'Espoir inflow shows no internal inconsistencies.

This result shows that the distribution of the flows among the sub-basins requires rectification. Apparent underestimation of inflows in certain sub-basins is at least partly compensated for by over-estimates in others.

A.10 Summary

The Hydro inflow series, except for Victoria sub-basin, do not appear to be wholly consistent with the corrected dataset (SGE Acres, 2004). The reason for this is unknown. However, the totals of the Hydro inflows at Upper Salmon and Bay d'Espoir Generating Stations are generally consistent with the corrected dataset and show no significant trend or change; as a result, there should be no adverse impact on the accuracy of the generation estimates at these facilities. The total of the Hydro inflows at Granite Canal Generating Station after 1980 is slightly higher than that of the corrected dataset, but any resulting error in the estimate of total system generation is expected to be small, since Granite Canal accounts for only a small portion of the total system capacity.

There is no evidence of significant trend or change in the natural streamflow series. Any appearance of trend or change in the reference inflow series is therefore expected to be due to inflow calculation methods and does not signify any actual hydrological phenomenon. There are some apparent inconsistencies in the distribution of sub-basin inflows within the system, but these tend to balance each other out.

It is concluded that, for the purpose of this study, the Hydro inflow series may be used as provided, for the power and energy analysis of the proposed new Unit 8.

Summary tables of test results are provided as follows.

Table A-2: Normality Test Summary

Name of Series	Years	n	Shapiro-Wilk p-value	Normal? (p>0.05)
Victoria Lake	1970-2019	50	0.612	Yes
Burnt Pond	1970-2019	50	0.865	Yes
Granite Lake	1970-2019	50	0.255	Yes
Meelpaeg Lake	1970-2019	50	0.038	No
Great Burnt Lake	1970-2019	50	0.355	Yes
Cold Spring Pond	1970-2019	50	0.330	Yes
Long Pond	1970-2019	50	0.450	Yes

Table A-3: Monotonic Trend Test Summary

Name of Series	Years	n	Linear Regression (Parametric) p-value	Mann-Kendall (Non-parametric) p-value	Trend category
Hydro Inflow Series					
Victoria Lake	1970-2019	50	0.621	0.894	3 - weak or no trend
Burnt Pond	1970-2019	50	**0.002**	**0.002**	**1 - significant increasing trend**
Granite Lake	1970-2019	50	**0.009**	**0.007**	**1 - significant increasing trend**
Meelpaeg Lake	1970-2019	50	n/a	0.592	3 - weak or no trend
Great Burnt Lake	1970-2019	50	**<0.001**	**<0.001**	**5 - significant decreasing trend**
Cold Spring Pond	1970-2019	50	**<0.001**	**<0.001**	**5 - significant decreasing trend**
Long Pond	1970-2019	50	0.052	0.066	2 - mild increasing trend
Total Bay d'Espoir	1970-2019	50		0.575	3 - weak or no trend
WSC Streamflow Series					
Bay du Nord River	1970-2017	47	-	0.304	3 - weak or no trend
Gander River	1970-2019	50	-	0.349	3 - weak or no trend
Lewaseechjeech Brook	1973-2017	44	-	0.808	3 - weak or no trend

Table A-4: Step Trend Test Summary

Name of Series	Years	n	t-test (Parametric)		Mann-Whitney (Non-parametric)		Step change	
			1982/1983 p-value	2002/2003 p-value	1982/1983 p-value	2002/2003 p-value	1982/1983	2002/2003
Hydro Inflow Series								
Victoria Lake	1970-2019	50	0.248	0.866	0.550	0.984	no change	no change
Burnt Pond	1970-2019	50	0.209	**<0.001**	0.200	**<0.001**	no change	**increase**
Granite Lake	1970-2019	50	0.100	**0.025**	0.093	**0.007**	no change	**increase**
Meelpaeg Lake	1970-2019	50	n/a	n/a	0.642	0.176	no change	no change
Great Burnt Lake	1970-2019	50	**0.010**	**0.009**	**0.009**	**0.017**	**decrease**	**decrease**
Cold Spring Pond	1970-2019	50	**0.010**	**0.009**	**0.009**	**0.018**	**decrease**	**decrease**
Long Pond	1970-2019	50	0.241	**0.036**	0.200	**0.039**	no change	**increase**
Total Bay d'Espoir	1970-2019	50	0.940	0.153	0.956	0.486	no change	no change
WSC Streamflow Series								
Bay du Nord River	1970-2017	47	-	-	0.386	0.982	no change	no change
Gander River	1970-2019	50	-	-	0.808	0.082	no change	no change
Lewaseechjeech Brook	1973-2017	44	-	-	0.641	0.747	no change	no change

Table A-5: Runs Test Summary

Name of Series	Years	n	Runs Test p-value	Random? (p>0.05)
Victoria Lake	1970-2019	50	0.884	Yes
Burnt Pond	1970-2019	50	0.319	Yes
Granite Lake	1970-2019	50	0.319	Yes
Meelpaeg Lake	1970-2019	50	0.116	Yes
Great Burnt Lake	1970-2019	50	0.319	Yes
Cold Spring Pond	1970-2019	50	0.319	Yes
Long Pond	1970-2019	50	0.884	Yes

Appendix B
Hydro Reference Inflow Series

Sequence	**Victoria Lake Inflow**		**Burnt Pond Inflow**		**Granite Lake Inflow**		**Meelpaeg Lake Inflow**		**Great Burnt Lake Inflow**		**Cold Spring Pond Inflow**		**Long Pond Inflow**	
Drainage Area (km^2)	1058		679		503		969		630		290		1774	
Year	**mm**	**million m^3**	**mm**	**million m^3**	**mm**	**million m^3**	**mm**	**million m^3**	**mm**	**million m^3**	**mm**	**million m^3**	**mm**	**million m^3**
1950	825	873	733	498	733	369	733	710	796	502	796	231	614	1089
1951	1168	1236	1060	720	1060	533	1060	1027	1033	651	1033	300	959	1702
1952	1079	1142	1098	746	1098	552	1098	1064	1237	780	1238	359	988	1752
1953	1069	1131	1022	694	1022	514	1022	990	1009	636	1009	293	912	1618
1954	1215	1285	1180	801	1180	594	1180	1144	1252	789	1253	363	1058	1878
1955	1009	1068	924	628	924	465	924	896	987	622	988	286	822	1458
1956	1097	1161	1105	750	1105	556	1105	1070	1236	779	1236	358	970	1720
1957	1203	1273	973	661	973	490	973	943	891	561	891	258	821	1456
1958	1297	1372	1125	764	1125	566	1125	1090	1011	637	1011	293	964	1711
1959	978	1035	841	571	841	423	841	815	812	511	812	235	733	1301
1960	919	972	755	512	755	380	755	731	750	472	750	217	652	1156
1961	880	931	751	510	751	378	751	728	730	460	730	212	607	1077
1962	1175	1243	1201	815	1201	604	1201	1164	1352	852	1352	392	1123	1992
1963	1221	1292	1222	830	1222	615	1222	1184	1448	912	1448	420	1107	1963
1964	1086	1149	1072	728	1072	539	1072	1039	1222	770	1222	355	974	1728
1965	961	1017	1020	692	1020	513	1020	988	1137	716	1137	330	909	1613
1966	938	992	852	578	852	428	852	825	922	581	922	267	748	1326
1967	1078	1140	1092	741	1092	549	1092	1058	1147	723	1147	333	927	1645
1968	1180	1249	1146	778	1146	576	1146	1110	1060	668	1060	307	988	1752
1969	1379	1459	1276	866	1275	642	1276	1236	1121	706	1121	325	1098	1947
1970	1074	1137	1056	717	1056	531	1056	1023	1189	749	1188	345	947	1680
1971	1320	1396	1158	787	1158	583	1158	1122	1157	729	1157	336	1091	1936
1972	1384	1464	1186	805	1186	596	1186	1149	1192	751	1192	346	1021	1811
1973	1113	1177	1100	747	1100	553	1100	1066	1139	717	1138	330	942	1671
1974	1020	1079	1011	687	1011	509	1011	980	1020	642	1019	296	900	1596
1975	1008	1067	912	619	912	459	912	884	892	562	892	259	815	1445
1976	1206	1276	1174	797	1174	590	1174	1137	1188	748	1187	344	1088	1931
1977	1501	1589	1271	863	1271	639	1271	1231	1299	819	1299	377	1114	1977
1978	993	1051	838	569	838	421	838	812	920	579	920	267	754	1338
1979	1171	1239	908	616	908	457	908	879	903	569	903	262	850	1508
1980	1176	1244	1128	766	1128	568	1128	1093	1135	715	1135	329	983	1745
1981	1433	1516	1413	959	1525	767	1529	1481	1000	630	1000	290	1029	1825
1982	1061	1123	1104	750	1210	608	1214	1176	805	507	805	233	829	1470
1983	1387	1468	1361	924	1491	750	1496	1450	981	618	981	284	1184	2100
1984	1190	1259	1170	795	1282	645	1287	1247	1016	640	1016	295	1116	1980
1985	745	788	765	519	838	422	841	815	819	516	819	237	702	1245
1986	944	999	945	641	1035	521	1039	1006	817	515	817	237	839	1488
1987	1024	1083	897	609	983	495	987	956	704	443	704	204	768	1363
1988	1114	1179	997	677	1092	549	1096	1062	1152	726	1152	334	911	1617
1989	842	891	777	527	851	428	854	827	896	564	896	260	695	1234
1990	1195	1264	1075	730	1178	593	1182	1145	937	590	937	272	1004	1781
1991	1012	1071	944	641	1035	520	1038	1006	1074	677	1075	312	848	1504
1992	1080	1142	966	656	1059	533	1062	1030	1241	782	1241	360	903	1602
1993	1422	1504	1294	878	1417	713	1422	1378	1360	857	1360	394	1280	2271
1994	1163	1230	1051	714	1152	579	1155	1120	1126	709	1126	327	973	1727
1995	1174	1242	1080	733	1330	669	1334	1293	816	514	816	237	1125	1997
1996	1189	1258	1171	795	1183	595	1187	1150	916	577	916	266	1032	1830
1997	1101	1165	1156	785	1198	602	1202	1164	975	614	975	283	979	1736
1998	1255	1328	1484	1007	956	481	959	929	1133	714	1133	329	1065	1889
1999	1365	1445	1302	884	1716	863	1722	1669	662	417	662	192	1191	2114
2000	1320	1397	1258	854	1783	897	1789	1734	562	354	562	163	1251	2220
2001	831	879	827	562	827	416	826	801	825	520	825	239	770	1365
2002	1021	1080	1122	762	1127	567	648	627	910	573	910	264	779	1381
2003	1228	1299	1526	1036	1519	764	784	760	1189	749	1189	345	1086	1926
2004	1186	1255	1231	836	1230	618	1055	1022	1147	723	1147	333	1114	1976
2005	1167	1235	1284	872	1291	650	905	877	1116	703	1129	327	1079	1914
2006	1133	1199	1310	889	1309	658	1032	1000	891	561	891	258	1071	1900
2007	979	1036	1050	713	1050	528	893	865	796	502	796	231	723	1282
2008	1209	1280	1444	980	1444	726	1169	1133	1007	634	1007	292	1233	2188
2009	1178	1246	1312	891	1312	660	1146	1110	883	557	883	256	1058	1877
2010	962	1017	1049	712	1049	527	950	921	825	520	825	239	1022	1812
2011	1089	1152	1289	875	1289	649	1064	1031	581	366	581	168	1242	2203
2012	1032	1092	1206	819	1206	606	976	946	841	530	841	244	1006	1784
2013	1429	1512	1598	1085	1598	804	1210	1172	465	293	466	135	1389	2465
2014	1185	1254	1370	930	1544	777	1124	1089	736	464	736	213	1186	2105
2015	1047	1108	1165	791	1165	586	863	837	598	377	598	173	871	1545
2016	1187	1256	1346	914	1346	677	1269	1230	939	591	939	272	1200	2128
2017	887	938	958	650	958	482	750	727	600	378	600	174	719	1275
2018	1266	1340	1530	1039	1530	770	1210	1173	932	587	932	270	1175	2085
2019	1184	1253	1325	900	1325	666	1184	1147	585	368	585	170	1002	1777
Mean	1128	1193	1119	760	1152	579	1081	1047	972	612	972	282	970	1722

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Abbreviations

Term	Definition
2018 Filing	"Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018)
2019 Update	"Reliability and Resource Adequacy Study - 2019," Newfoundland and Labrador Hydro, November 15, 2019
2022 Update	Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022
2023 Update	Reliability and Resource Adequacy Study – 2023 Update
Additional Considerations Report	"*Reliability and Resource Adequacy Study* – Additional Considerations of the Labrador-Island Link Reliability Assessment and Outcomes of the Failure Investigation Findings," Newfoundland and Labrador Hydro, December 22, 2021
AACE	Association for Advancement of Cost Engineering
BA-P-012	Operations Standard Instruction BA-P-012 (T-001) Operating Reserves
Board	Board of Commissioners of Public Utilities
CBPP	Corner Brook Pulp and Paper Limited
CDM	Conservation and Demand Management
CEA	Canadian Electricity Association
CF(L)Co	Churchill Falls (Labrador) Corporation
CFA	Cumulative Frequency Analysis
Churchill Falls	Churchill Falls Generating Station
CPP	Critical Peak Pricing
DAFOR	Derated Adjusted Forced Outage Rates
DAUFOP	Derated Adjusted Utilization Forced Outage Probabilities
DOMAE	Department of Municipal Affairs and Environment

Term	Definition
Dunsky	Dunsky Energy + Climate
ECDM	Electrification, Conservation and Demand Management
EFLA	EFLA Consulting Engineers
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
EM	Energy Marketing
Emera	Emera Inc.
EV	Electric Vehicle
FAT	Factory Acceptance Testing
FOR	Forced Outage Rate
GDP	Gross Domestic Project
GE	GE Grid Solutions
Haldar & Associates	Halder & Associates Inc.
Hatch	Hatch Ltd.
Holyrood TGS	Holyrood Thermal Generating Station
HVac	High Voltage Alternating Current
HVdc	High-Voltage Direct Current
Hydro	Newfoundland and Labrador Hydro
IOC	Iron Ore Company of Canada
Liberty	The Liberty Consulting Group
Liberty's Review	"Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," filed with the Board on August 19, 2019

Term	**Definition**
LIL	Labrador-Island Link
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTA	Labrador Transmission Assets
Network Additions Policy	*Network Addition Policy – Labrador Interconnected System*
Newfoundland Power	Newfoundland Power Inc.
NERC	North American Electricity Reliability Corporation
NLSO	Newfoundland and Labrador System Operator
Nova Scotia Block	The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the Muskrat Falls Hydroelectric Generating Facility on peak.
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operators
O&M	Operations and Maintenance
OASIS	Open Access Same-Time Information System
Reference Question	*Rate Mitigation Options and Impacts Reference* proceeding
Reliability Model	Detailed Hourly System Model
Resource Planning Model	Long-Term Resource Planning Model
SEM	System Equipment and Maintenance
Supplemental Energy	Commitment to Firm Energy
Synapse	Synapse Energy Economic
TOU	Time of Use

Term	Definition
TP-TN-068	Technical Note TP-TN-068 – Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage
TwinCo	Twin Falls Power Corporation Limited
UFOP	Utilization Forced Outage Probability
Utilities	Newfoundland and Labrador Hydro and Newfoundland Power Inc., collectively
Vale	Vale Newfoundland and Labrador Limited

Definitions

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers within the system criteria, taking into account scheduled and unscheduled outages of system elements.[1]

Adjusted Gross Domestic Product: Excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Balancing Authority: The Balancing Authority is defined by NERC as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Base Case: The base case is the expected case, determined by using the assumptions considered most likely to occur.

Beneficial Electrification: Beneficial electrification (or strategic electrification) is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs for customers.

Bridging Period: The Bridging Period is defined as the period from 2023 to 2030.

Capacity Assistance: Contracted curtailable loads and customer generation that can be called on for system support. Capacity assistance agreements are generally restricted in terms of frequency, duration and annual usage.

Class 3 Cost Estimate: A Class 3 cost estimate is an estimate based on preliminary design documentation. The accuracy of the cost estimate varies between less than 20 percent or more than 30 percent of the estimated cost.

Coincidence Factor: The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System, it provides a measure of the relative contribution of the Island Interconnected System and the Labrador Interconnected System peaks to the combined Newfoundland and Labrador Interconnected System Peak.

Consumer Price Index: The consumer price index is an indicator of the change in consumer prices. It measures price change by comparing through time the cost of a fixed-basket of consumer goods and services.[2]

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[1] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

[2] Statistics Canada, "Chapter 1 – Introduction to the Canadian Consumer Price Index," November 30, 2015. <https://www150.statcan.gc.ca/n1/pub/62-553-x/2014001/chap/chap-1-eng.htm>

Critical Peak Pricing: Critical peak pricing offers customers time-varying rates that reflect the cost of capacity during critical peak times. By significantly increasing the rate during that time, customers are incented to significantly shift or reduce demand during the critical peak period.

Curtailable Load: A load, typically commercial or industrial that can be interrupted at the request of the system operator.

Demand: (1) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. (2) The rate at which energy is being used by the customer.[3]

Demand-Side Management (also known as Customer Demand Management): The term for all activities or programs undertaken by the utility and/or its customers to influence the amount or timing of electricity they use.[4]

Derated Adjusted Forced Outage Rate ("DAFOR"): Measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating ("MCR") due to forced outages.

Derated Adjusted Utilization Forced Outage Probability ("DAUFOP"): The probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

Deterministic Analysis: Uses a set of known and fixed system conditions and probabilities (load, forced outage rates, transmission flows, and intermittent generation) to determine system reliability. Deterministic analysis is computationally efficient but does not consider many of the uncertainties present in real-world systems.

Dispatchable Resource: A dispatchable resource is a generation resource that can be used on demand and increased or decreased at the request of operators, according to system needs.

Effective Load Carrying Capability ("ELCC"): A metric used to assess firm capacity credit for intermittent generation resources. It is a measure of the additional load that the system can supply with the addition of a generator with no net change in reliability.

Electrical Power Control Act, 1994 ("EPCA"): The Act which regulates the electrical power resources of Newfoundland and Labrador.[5]

Emergency Operating Procedure ("EOP"): A procedure that includes a number of possible mitigating actions that can be enacted by the system operator, as required, to provide system relief.

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[3] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[4] Ibid.
[5] *Electrical Power Control Act, 1994, 1994* c E-5.1, <https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>

Expected Unserved Energy ("EUE"): A measure of the amount of customer demand not served due to generation shortfalls.

Firm Capacity: the amount of generation capacity available for production or transmission expected to be available at the annual peak when the unit is fully operational.

Firm Demand: That portion of the demand that a power supplier is obligated to provide, except when system reliability is threatened or during emergency conditions.[6]

Firm Energy: Firm energy refers to the actual energy guaranteed to be available to meet customer requirements on an annual basis.

Firm Imports and Exports: A contract for the import or export of capacity or energy guaranteed to be available at a given time.

First Contingency: The first contingency is the unexpected failure or outage of a system's largest component, such as a generator or transmission line.

Forced Outage: (1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. (2) The condition in which the equipment is unavailable due to unanticipated failure.[7]

Forced Outage Rate ("FOR"): The expected level of unavailability of a unit due to unforeseen circumstances.

Future Period: The period beyond 2030 (the Bridging Period).

Gross Domestic Product ("GDP"): GDP is the total unduplicated value of the goods and services produced in the economic territory of a country or region during a given period.[8]

Interruptible Load: Interruptible load is a load, typically commercial or industrial, that can be interrupted in the event of a capacity deficiency in the supplying system.

Island Interconnected System: The interconnected portion of the island's electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, the Holyrood Thermal Generating Station on the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. The Island Interconnected System is interconnected to the Labrador Interconnected System via the Labrador-island Link ("LIL"). The Island Interconnected System is also connected to the North American grid via the Maritime Link.

[6] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[7] Ibid.
[8] Statistics Canada, "Gross Domestic Product (GDP).", September 20, 2017 <https://www.statcan.gc.ca/eng/nea/list/gdp>

Labrador Interconnected System: The interconnected portions of Labrador's electrical system form the Labrador Interconnected System. It is characterized by supply at Churchill Falls (provided by TwinCo Block and Recapture Energy), radial transmission to the two major load centres in Labrador East and Labrador West, and the Labrador Transmission Assets ("LTA") connecting Churchill Falls to Muskrat Falls. The Labrador Interconnected System is connected to the Island Interconnected System via the LIL. The Labrador Interconnected System is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Quebec.

Labrador-Island Link ("LIL"): A 900 MW high voltage dc transmission line designed to deliver power from the Muskrat Falls Generating Station to Soldiers Pond Terminal Station on the Avalon Peninsula.

Level 2 Schedule: A Level 2 schedule is the first level of scheduled detail where logical task relationships may be shown. It often includes a breakout of the various disciplines responsible for the activities in each phase, the critical engineering and procurement activities, and the major elements of construction by work area.

Load Forecast: The projected energy and demand requirements for the electrical system. The load forecast process entails translating a long-term economic and energy price forecast for the Province into corresponding electric demand and energy requirements for the electric power systems. Hydro predicts future load requirements for the Island Interconnected System primarily through econometric modelling techniques and large industrial customer input. Future load requirements for the Labrador Interconnected system are primarily through historical trend analysis and large industrial customer input.

Load Forecast Uncertainty: A multiplier representing the potential variance in annual peak demands. Its development is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.

Loss of Load Expectation ("LOLE"): The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.

Loss of Load: Loss of load refers to instances where some system load is not served, firm commitments are not met, or minimum operational reserve limits are violated.

Loss of Load Hours ("LOLH"): Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the LOLE calculation.

Loss of Load Probability ("LOLP"): The probability of system daily peak or hourly demand exceeding available generating capability in a given study period.

Maritime Link: A high voltage dc transmission line connecting Newfoundland and Nova Scotia.

Maximum Continuous Rating ("MCR"): The maximum continuous rating is defined as the maximum output in MW that a generating station is capable of producing continuously under normal operating conditions over a year.

Monte Carlo Simulation: A mathematical technique that generates random variables for modelling risk or uncertainty of a certain system.

Newfoundland and Labrador Interconnected System: The Island Interconnected System and the Labrador Interconnected System combine to form the Newfoundland and Labrador Interconnected System.

North American Electric Reliability Corporation ("NERC"): A non-profit, self-regulating organization whose objective is to ensure adequate reliability of the bulk power system in North America.

Northeast Power Coordinating Council, Inc. ("NPCC"): NPCC is a regional entity division which operates under a delegation agreement with the North American Electric Reliability Corporation (NERC). Members include the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia.

Nova Scotia Block: A firm commitment of 980 GWh, to be supplied annually from the Muskrat Falls Generating Station on peak.

Non-Dispatchable Resource: A non-dispatchable resource is an energy resource, such as wind power, that can not be used on demand and dispatched as per system needs.

Non-Firm Imports and Exports: A contract for the import or export of capacity or energy which is not guaranteed to be available at a given time.

Non-Spinning Reserve: (1) That generating reserve not connected to the system but capable of serving demand within a specified time. (2) Interruptible load that can be removed from the system in a specified time.[9]

Normalized Expected Unserved Energy: A measure of the amount of customer demand not served due to generation shortfalls divided by the total system energy.

Operational Reserve: A system requirement where the system requires the ability to withstand the loss of the single largest resource while maintaining an additional reserve.

Peak Demand: The highest hourly demand on a system occurring within a year.[10]

Planning Reserve Margin: The reserve margin at which the system reliability is at criteria. It is used as a reliability metric to evaluate the system's resource adequacy for expansion planning.

Probabilistic Analysis: Probabilistic analysis simulation requires completion of several simulations using randomly sampled variables like outage profiles, wind generation and weather related load uncertainty to determine system reliability. When compared to deterministic analysis, probabilistic analysis better

[9] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[10] Ibid.

incorporates the random behavior of system states as well as the operational restrictions of the system. See Monte Carlo Analysis.

Power Purchase Agreement ("PPA"): A contract for the purchase of capacity and/or energy from a third party.

Punchlist: Punchlist items are a list of incomplete scope and/or deficiencies agreed between Contractor offering the equipment, system or part system and the RFO receiving the equipment, system or part system.

P50 Forecast: A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50 percent of the time and above 50 percent of the time (i.e.. the average forecast.)

P90 Forecast: A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90 percent of the time and above 10 percent of the time (i.e., there is a 10 percent chance of the actual peak demand exceeding the forecast peak demand.)

Regulating Reserve: Unlike other reserves that are used in response to contingencies (i.e., operating reserves), regulating reserves are used throughout an operating hour to maintain system frequency in response to fluctuations in loads and in output from variable generation resources.

Reserve Margin: The amount by which available firm capacity exceeds capacity required to meet peak demand.

Return Period: Return period, also known as recurrence interval, is an estimate of the likelihood of a climatological event to occur. It is usually used for risk analysis (e.g., to design structures to withstand an event with a certain return period).

Run-of-River: Hydroelectric generating facilities with limited storage capability, where production is dictated by the water available in the river at the time of generation.

Sensitivities: Cases developed to study the impact of change in variables on resource planning analysis. These sensitivities include addition of large loads in Labrador, and the uncertainty in load projections associated with future customer rates.

Spinning Reserve: Unloaded generation that is synchronized and ready to serve additional demand.[11] Also referred to as synchronized reserve.

Supplemental Energy: A firm energy commitment to supply energy to Nova Scotia during the first five years of production at the Muskrat Falls Generating Station as part of the Amended and Restated Energy and Capacity Agreement.

Synchronized Reserve: Refer to Spinning Reserve.

[11] Ibid.

System Operator: Entity entrusted with the operation of the control center and the responsibility to monitor and control the electric system in real time.[12]

Time-of-use-Rates: An option for customers that offers electricity rates that vary throughout the day based on load patterns; with the highest rates during peak hours and lowest rates during off-peak hours.

Transmission Constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.[13]

Under Frequency Load Shedding ("UFLS"): the automatic or manual actions required to shed system load when the system frequency falls below defined acceptable parameters, to bring the system back in balance.

Utilization Forced Outage Probability ("UFOP"): is the probability that a generating unit will not be available due to forced outages when there is demand on the unit to generate.

Weather Adjusted Peak Demand: Weather adjustment is a process that adjusts actual peak outcomes to what would have happened under normal or average weather conditions. The weather adjustment is derived from Hydro's Newfoundland Power native peak demand model and the results are extrapolated to adjust Hydro's Island Rural peak.

[12] Ibid.
[13] Ibid.