Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 I f. 709.737.1800
nlhydro.com

March 31, 2023

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: Long-Term Supply for Southern Labrador – Phase 1 – Midgard Consulting Inc. Report

On April 7, 2022[1] and May 16, 2022,[2] the Board of Commissioners of Public Utilities ("Board") provided correspondence to Newfoundland and Labrador Hydro ("Hydro") with respect to Hydro's application for approval of the construction of Phase 1 of Hydro's long-term supply plan for southern Labrador ("Application").[3] In its correspondence, the Board requested that Hydro provide additional information and analysis to supplement the information on the record and stated that Hydro should engage an independent expert to assist in the analysis of the options and approach for the provision of service in southern Labrador.[4]

On June 22, 2022, Hydro met with Board staff to review the scope of work Hydro proposed would form the basis of a request for proposals ("RFP") to identify and retain a consultant to carry out the independent analysis requested by the Board. Hydro subsequently issued the RFP and selected Midgard Consulting Inc. ("Midgard") to carry out this analysis. On March 28, 2023, Hydro received Midgard's report, "Southern Labrador Communities – Integrated Resource Plan,"[5] which is included as Attachment 1.

Midgard's analysis largely confirms the conclusions of Hydro's analysis provided with the Application. Midgard's recommendation is for Hydro to proceed with the interconnection of the communities of southern Labrador and the establishment of a regional diesel generating station. This recommendation is based on the conclusion that interconnection is the most cost-effective and reliable solution for the provision of service to the communities of southern Labrador, including Charlottetown and Pinsent's Arm. Midgard's recommendation differs from the proposal Hydro put forth in its Application in that

---

[1] "Newfoundland and Labrador Hydro - 2021 Capital Budget Supplemental Application Approval of the Construction of Phase 1 of Hydro's Long-term Supply Plan for Southern Labrador - To NLH - Further Information Required Before Schedule is Resumed," Board of Commissioners of Public Utilities, April 7, 2022.
[2] "Newfoundland and Labrador Hydro - 2021 Capital Budget Supplemental Application Approval of the Construction of Phase 1 of Hydro's Long-term Supply Plan for Southern Labrador – Response to Hydro's Letter dated April 26, 2022," Board of Commissioners of Public Utilities, May 16, 2022.
[3] "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021.
[4] "Newfoundland and Labrador Hydro - 2021 Capital Budget Supplemental Application Approval of the Construction of Phase 1 of Hydro's Long-term Supply Plan for Southern Labrador - To NLH - Further Information Required Before Schedule is Resumed," Board of Commissioners of Public Utilities, April 7, 2022.
[5] "Southern Labrador Communities – Integrated Resource Plan," Midgard Consulting Inc., March 28, 2023.

Midgard’s recommendation is for Hydro to proceed with the full interconnection of all southern Labrador communities, rather than a phased implementation. A further difference is to design the regional diesel generating station with N-1 reliability, rather than N-2 as Hydro proposed.

To continue to advance this matter as quickly as possible, Hydro will give Midgard’s recommendations serious consideration in determining how to proceed. Hydro intends to engage its stakeholders without delay to ensure that all parties are informed and have the opportunity to provide input on the project before further decisions are made. Following this, Hydro expects to file an update with the Board before the end of April 2023, detailing any revisions in cost, schedule, or scope resulting from consideration of Midgard’s recommendations and the passage of time since the original application in 2021.

Hydro respectfully requests that the Board establish a schedule for the remaining regulatory review process as quickly as possible thereafter, to enable decisions and implementation of a long-term supply solution for the communities of Charlottetown and Pinsent’s Arm.

A summary of Midgard’s findings as they relate to the concerns outlined by the Board is included herein.

Midgard Analysis of Alternatives

Midgard evaluated numerous alternative long-term supply solutions for southern Labrador. It considered the viability of ten different resource technologies, the practicality of using battery energy storage systems as a source of firm capacity, and numerous detailed alternatives based on eight base scenarios and multiple sub-variations to account for different reliability criteria, development timing, and other factors. The scenarios aimed to satisfy three supply criteria—capacity, energy, and reliable backup. The alternatives considered ranged from refurbishing existing stations and maintaining isolated community services to constructing new regional generating stations (thermal or hydraulic) with full interconnections and voltage conversions or interconnection with the Labrador Interconnected System.

Midgard acknowledges that intermittent renewable energy sources, such as wind and solar generation, may be viable for the provision of energy; however, to provide firm capacity, intermittent resources must be paired with energy storage with the capacity to supply the system for several days in the event of low renewable generation. Regarding the future cost-effectiveness of battery energy storage systems, Midgard concluded that renewable energy sources with sufficient battery storage to provide firm capacity remains cost prohibitive at this time. Midgard's report indicates that based on the most optimistic projections, battery prices may drop by up to 70% over the next 25 years, with the largest price drops expected in the next 10 years being approximately 55%. Despite these potential price reductions, Midgard concludes that it is unlikely for renewable systems with battery firming to become cost-competitive with thermal generation systems within the next decade.

Midgard's report highlights several benefits of interconnecting the communities to a regional generating facility, including operational savings due to reduced fuel consumption, improved system reliability, reduced capital costs, and greater potential for renewable penetration. Midgard notes that the interconnected system would allow greater penetration of renewable energy, and therefore greater opportunity to offset diesel fuel usage. Midgard notes that proceeding with the full interconnection, rather than phased interconnection, is more cost-effective and in fact may enable greater renewable penetration sooner.

Midgard notes that the use of diesel gensets[6] in Hydro's proposed approach is consistent with practices in other similar jurisdictions across Canada. Diesel generation remains a common solution for remote communities due to its reliability, ease of installation, and cost-effectiveness. Midgard's analysis of similar jurisdictions provides context for the proposed approach and supports its suitability for the southern Labrador system.

Midgard conducted a cost-benefit analysis considering both direct costs, such as capital investments and operational expenses, and indirect costs, such as environmental impacts and potential economic benefits. Midgard also carried out a sensitivity analysis considering the impacts of ten variables, including carbon and diesel fuel costs. Midgard's analysis suggests that the upfront capital costs of interconnecting the four systems and six communities will be offset by operational savings over a 25-year period. This is consistent with Hydro's analysis on the record supporting the interconnection of the communities of southern Labrador.

Based on its findings, Midgard notes that an N-2 planning standard provides marginal benefits in overall customer reliability and may not warrant the additional cost. Midgard recommends immediate construction of a regional diesel generating station to an N-1 planning standard, interconnecting all four systems and upgrading to 25 kV in each community.

Requirement for Backup Generation

Midgard's assessment emphasized the importance of maintaining reliable backup generation to ensure the continuous supply of electricity for southern Labrador communities should regional or community-based renewable energy solutions advance or a larger interconnection to the Labrador Interconnected System come to fruition. Regardless of the alternative chosen, Midgard notes that a dependable diesel generation solution is required to provide capacity and energy during emergencies or periods of high demand.

Integration of Renewables

Midgard recommends that Hydro pursue power purchase agreements ("PPA"), particularly through partnerships with Indigenous stakeholders, to integrate renewable energy sources into the system. This approach will help offset diesel fuel usage, reduce greenhouse gas emissions, and provide potential economic benefits to the communities. By considering a maximum displacement of 25% to 50% energy from renewables depending on the scenario, Midgard acknowledges the role of renewable energy in enhancing the overall sustainability of fossil fuel alternatives. Midgard emphasizes the importance of Indigenous involvement in renewable energy projects and recommends that Hydro actively support and engage Indigenous groups in the procurement of renewable energy supplies. This approach aligns with federal policies that favor Indigenous-led development of renewable energy projects, contributing to the growth of Indigenous communities and fostering a more inclusive energy sector, which is consistent with Hydro's existing strategy for the integration of renewable energy.

[6] Diesel generating units are referred to as "gensets."

Alternative Fuels

Midgard assessed options such as compressed natural gas, liquefied natural gas, biodiesel, and hydrogen. They concluded that these alternatives are not currently cost-effective for the southern Labrador diesel generation systems. Midgard also noted that alternative fuels may present technical or logistical challenges, such as cold weather performance, that preclude their use at this time. However, Midgard notes that Hydro should continue to monitor developments in these areas as emerging technologies may become more favorable in the future. Hydro notes that a regional diesel generating station would not preclude Hydro from availing of alternative fuels, should they become technically and economically feasible in the future.

Demand Side Management

Midgard assessed the viability of demand side management ("DSM") for load reduction in southern Labrador. They concluded that, while there may be opportunities for further demand reduction, demand-side management is unlikely to be effective in eliminating the need for additional firm capacity in southern Labrador, as Hydro has already availed of most opportunities to incentivize energy efficiency and manage customer demand. Midgard notes that by interconnecting multiple communities with non-concurrent peak loads, Hydro will be able to avail of many of the benefits typically achieved through DSM. Midgard notes that DSM may improve the ability to accommodate load growth. Midgard does note that there may be limited potential for load reduction through conversion from resistive electric heat to heat pumps; however, Midgard notes that care must be taken to not incentivize conversion from other fuel sources to electric heating.

Midgard's recommendation is that Hydro undertakes further study in this regard. Hydro notes that since 2021, it has implemented pilot programs assessing the viability of cold climate heat pumps and shifted energy technology for demand management. These ongoing pilot programs will provide Hydro with the data to inform a decision regarding broader implementation of the programs. Additionally, Hydro is working with community stakeholders to explore the use of alternative fuels, such as wood heat, to offset electricity usage on isolated systems and is exploring other DSM initiatives for future consideration, such as commercial energy audits.

2023 Federal Budget Clean Energy Incentives

On March 28, 2023, the Government of Canada released the 2023 federal budget,[7] which included a number of programs aimed at promoting the development of clean energy in support of a clean Canadian economy. Midgard has reviewed the 2023 federal budget and has concluded that while the full details of implementation of the new federal programs are not fully known at this time, the programs introduced would not change the outcome of Midgard's assessment. Midgard notes that federal incentives for the construction of renewable energy sources may render renewable energy development more attractive to Indigenous and community groups, allowing Hydro to maximize renewable energy penetration on the southern Labrador interconnected system through PPA partnerships.

---

[7] "Budget 2023: A Made-in-Canada Plan: Strong Middle Class, Affordable Economy, Healthy Future," Government of Canada, March 28, 2023.

A memo summarizing Midgard's opinion regarding the impacts of the 2023 federal budget on the "Southern Labrador Communities – Integrated Resource Plan"[8] is included as Attachment 2.

Provision of Reliable Service in the Interim Period

Since the loss of the Charlottetown Diesel Generating Station in 2019, the communities of Charlottetown and Pinsent's Arm have been served by a fleet of mobile diesel gensets. Hydro has experienced three failures on the mobile gensets since 2019, the most recent of which occurred on February 1, 2023. The frequency of these incidents further highlights the need to approve and begin the implementation of a long-term supply solution for the community as urgently as possible.

Until a fixed and permanent generating station is in place to serve the communities, Hydro is taking steps to support emergency preparedness, minimize the safety risk to the community, and ensure that multiple redundant units are available to minimize the risk of customer impact. As such, there is sufficient excess capacity on site in Charlottetown to meet peak community load forecasts even if multiple units are unavailable, as shown in Figure 1.

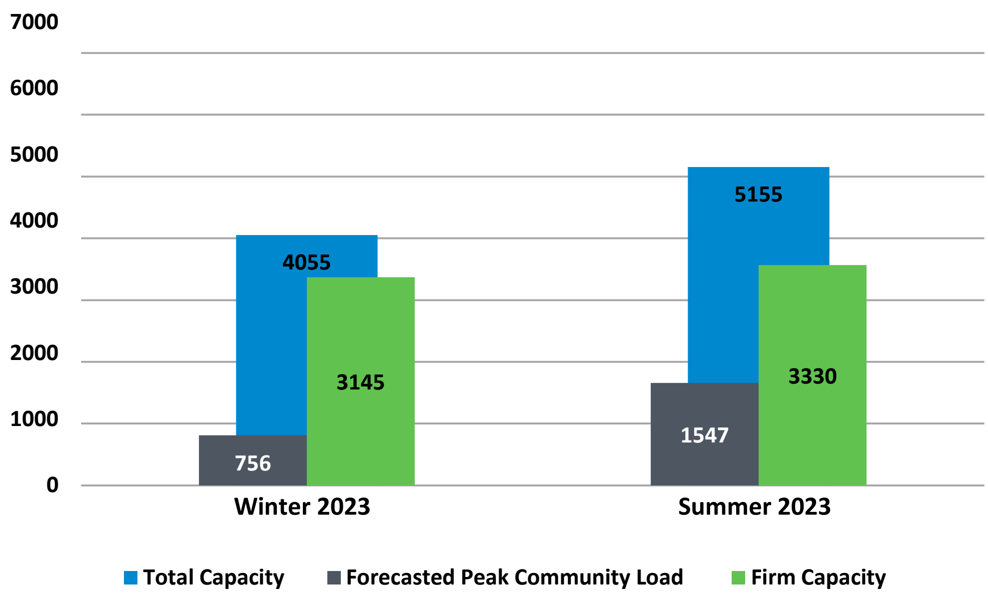


Figure 1: Charlottetown & Pinsent's Arm Excess Capacity by Season (kW)[9]

Hydro remains committed to ensuring safe and reliable supply to its customers in Charlottetown and Pinsent's Arm and continues to monitor the performance and reliability of its mobile diesel gensets to ensure it has sufficient redundancy and operational support to enable reliable service. Hydro has committed to providing the communities with quarterly written updates outlining the status of the temporary generation solution, as well as the status of the long-term solution throughout the regulatory approval and execution process.

---

[8] "Southern Labrador Communities – Integrated Resource Plan," Midgard Consulting Inc., March 28, 2023, included as Attachment 1 to this correspondence.

[9] Total capacity is defined as the total available generation, while firm capacity is defined as the available generation with the largest unit out of service.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Maureen Greene, KC
PUB Official Email

Labrador Interconnected Group
Senwung F. Luk, Olthuis Kleer Townshend LLP
Nicholas E. Kennedy, Olthuis Kleer Townshend LLP

Newfoundland Power Inc.
Dominic J. Foley
Lindsay S.A. Hollett
Regulatory Email

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Consumer Advocate
Dennis M. Browne, KC, Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis
Bernard M. Coffey, KC

Attachment 1

Southern Labrador Communities Integrated Resource Plan

Midgard Consulting Inc.

March 28, 2023

Southern Labrador Communities - Integrated Resource Plan

SUBMITTED BY

Midgard Consulting Inc.

DATE

March 28, 2023

Midgard, established in 2009, provides consulting services across the electrical power and utility sector. Midgard's principals and staff have direct experience in project development, design, contract procurement, finance, construction, and operations. This combined experience has translated into mandates in project due diligence, lender's technical advisor, loan guarantee assessments, and Independent Engineer roles in Canada, the United States, and internationally. Midgard has worked for developers, utilities, government agencies, and both project lenders and equity providers.

Midgard's team has extensive experience modelling fuel sources, creating energy yield estimates, reviewing contracts, reviewing pro-formas, and assessing project risks from a construction, operations, and financial perspective.

MIDGARD
CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

DOCUMENT CONTROL AND SIGN-OFF

DOCUMENT NUMBER

P0643-D026-RPT-R00-EXT

REVISION CONTROL

Revision	Description	Date
0	Issued for Use	March 28, 2023

REPORT SIGN-OFF

Prepared By:	***Michael Potyok, P.Eng., Midgard Consulting Inc.***	March 28, 2023 ***Date***
Checked By:	***Scott Martin, Midgard Consulting Inc.***	March 28, 2023 ***Date***
Approved By:	***Michael Potyok, P.Eng., Midgard Consulting Inc.***	March 28, 2023 ***Date***

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

EXECUTIVE SUMMARY

Midgard Consulting Inc. ("Midgard") was retained by Newfoundland and Labrador Hydro ("NLH") to prepare this Integrated Resource Plan ("IRP") for the six southern Labrador communities of Charlottetown, Lodge Bay, Mary's Harbour, Pinsent's Arm, Port Hope Simpson, and St. Lewis. These communities are currently served by four locally isolated diesel generation systems.

The Charlottetown generating station ("CHT") serves Charlottetown and Pinsent's Arm. This station currently operates mobile gensets and is considered a temporary configuration pending permanent replacement. The Mary's Harbour generating station ("MSH") serves Mary's Harbour and Lodge Bay. The MSH station is scheduled to be replaced in 2030 and currently requires significant capital investment to extend its life to that date. The other two generating stations each serve a single community, with the Port Hope Simpson generating station ("PHS") scheduled to be replaced in 2035 and the St. Lewis generating station ("SLE") scheduled to be replaced in 2045. Both of these generating stations will require genset replacement in the near future, as their existing gensets reach end of life.

This IRP adheres to the Newfoundland and Labrador Board of Commissioners of Public Utilities' ("PUB") instructions to NLH, including re-examination of the original alternatives proposed by NLH, as well as review and analysis of additional alternatives to address interventions raised in response to the original application.

In response, a number of system alternatives that could provide dependable capacity to the region were evaluated in this IRP and included reviews of NLH's previous assumptions and capital cost estimates. These include:

1. Construct a building enclosure at CHT to allow the continued use of all existing gensets to provide service to the four systems;
2. Replacement of CHT with a permanent generating station and continue the status quo operation of the remaining systems;
3. The interconnection of the four systems into a single 25 kV system, and either construct a Regional Plant near Port Hope Simpson, or continue to use distributed generation at existing stations; and
4. The connection of the four systems to the Labrador Interconnected System ("LIS"), which would require a secondary source of capacity – either two non-parallel transmission lines, or dependable generation near the communities to provide for requisite reliability against transmission outage.

Energy supply sources were also evaluated. These include thermal generation (diesel or natural gas generation) and many renewable technologies. Additional supply alternatives assessed included fully renewable systems with dependable capacity being provided by grid-scale battery storage and concluded that this was not a cost-effective solution.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

This IRP concludes that the immediate construction of a 25 kV interconnected system and regional diesel plant is the most cost-effective solution to provide Firm capacity to these six communities. This conclusion is materially less costly than continued islanded operation of 4 regional systems. Diesel use can be offset through the integration of wind and or solar renewable energy onto the system procured with Power Purchase Agreements ("PPA"s) from third parties which are likely to include Indigenous ownership and participation.

To reach this conclusion, Midgard reviewed the regulatory environment both in which NLH operates and in other jurisdictions across Canada. The recommended solution is consistent with NLH's legislated mandate to provide reliable, least cost service. The jurisdictional scan across Canada confirmed that the service of remote isolated communities remains primarily diesel driven, largely due to similar "least cost reliable" mandates.

Midgard reviewed NLH's load forecasts and the potential to use Demand Side Management (DSM) to mitigate existing loads or load growth. The overall load in the region is currently projected to remain stable but as a small system, single interconnection requests can materially change the load forecast. As a result, some degree of flexibility to accommodate new loads is therefore prudent. A significant potential for load growth identified was residents and businesses switching to electrical heating solutions because NLH provides subsidized electricity (below its cost of supply and below the cost of other energy uses such as heating oil). This unintended economic incentive can encourage fuel switching and load growth uncoupled from population growth and or industrial / commercial growth. Preliminary evaluation suggests that NLH undertake a further DSM study that specifically addresses this potential.

A review of many renewable generation technologies confirmed that the only practical sources of renewable supply for this region and system scale are wind, solar and hydro. However, these are unable to deliver dependable capacity that allows NLH to reliably deliver its service.

A series of supply scenarios, capable of meeting NLH's capacity, reliability, and energy supply requirements, were developed. These included alternatives previously studied by NLH as well as some new ones (such as the use of compressed natural gas as a fuel source). Various scenario parameters were investigated, including transmission and generation alternatives with varying levels of project phasing to defer capital costs. Scenarios were compared using a 25-year Discounted Cash Flow ("DCF") Model. A planning period of 25-years is considered appropriate for this study.

The implementation of a 25-kV interconnection (with or without a regional diesel plant) was investigated.

The preferred scenario has the least Net Present Cost ("NPC") of $158 million over the 25-year planning period. This is $5 million less than the least-cost phased approach, as proposed by NLH, which defers the

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

interconnection of SLE until 2045 and continues to use PHS as a generation source within an interconnected system. The value of investment deferred is somewhat muted in this model because of NLH's relatively low regulated return as well as nearer term capital expenditures needed to extend the life of CHT and MSH in their current configuration.

The NPC of the preferred scenario is $24 million less than continuing islanded operation with a new CHT generating station. The NPC of the preferred scenario is $17 million less than the scenario to continue to use an upgraded mobile genset-based CHT and continued operations using four remote systems. It is Midgard's opinion that use of mobile gensets as a planning resource to supply baseload electricity is not suitable.

Midgard's conclusions are robust, as demonstrated by a sensitivity analysis which compared results while changing key input assumptions, including cost of diesel, various capital, and operating costs and NLH's regulated rate of return. This sensitivity analysis also included potential changes in climate policy (specifically the imposition of a carbon tax on remote generation assets) on the proposed alternatives. While advances in technology could result in changes in system configurations, with decreases in costs of battery technology specifically reviewed, there were no technologies identified that would supersede existing technologies in the near to mid-term (5-10 years). Since NLH's current methodology is to incrementally replace units as they reach end of life, if new technologies become more cost effective NLH has the ability to replace these assets with more appropriate systems as they become available within their existing planning process.

Environmental impacts of alternate scenarios were examined and were similar to existing scenarios previously proposed by NLH. Although not technically an evaluation criterion under NLH's legislated mandate, a greenhouse gas ("GHG") emission comparison was carried out for those scenarios that were higher cost but resulted in lower lifetime emissions from diesel fuel use than the preferred scenario.

The lowest forecast emissions resulted from the interconnection of the communities to the Labrador Interconnected System. However, this scenario has an NPC of over $300 million. This $142 million cost premium over the recommended solution implies a per tonne value of GHGs of over $4,000. For context, current federal carbon pricing will increase from $65 per tonne of greenhouse gas (GHG) emissions in 2023 to $170 per tonne by 2030. Although societally attractive to reduce emissions from burning diesel, this value suggests that a much better return on investment would be achieved reducing emissions in other venues.

It is therefore recommended that NLH interconnect the six communities with a 25 kV system and construct a regional plant near Port Hope Simpson to provide firm capacity and energy while pursuing cost-competitive renewable energy procurement opportunities to offset day to day diesel consumption.

Respectfully submitted March 28, 2023.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

TABLE OF CONTENTS

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

LIST OF FIGURES

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

LIST OF TABLES

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1 LIST OF ACRONYMS

AUC	Alberta Utilities Commission
BCUC	British Columbia Utilities Commission
CANWEA	Canadian Wind Energy Association
CAT	Caterpillar Inc.
CER	Clean Electricity Regulations
CIC	Crown Investments Corporation
CHT	Charlottetown (generating station)
CNG	Compressed Natural Gas
CPI	Consumer Price Index
DCF	Discounted Cash Flow
DSM	Demand Side Management
dependable [generation or capacity]	A generation resource that can be expected to provide a known amount of electricity, on demand at any given time.
ELCC	Effective Load Carrying Capability
EPCA	Electrical Power Control Act
ESG	Environmental, Social and Governance
EUE	Expected Unserved Energy
Firm [capacity]	The amount of generation available on-peak, while simultaneously allowing for redundant resources to account system outage according to the relevant planning reliability standard.
GHG	Greenhouse Gas
GJ	Gigajoule
GSU	Generator Step-up Transformer
GWh	Gigawatt-Hour
HMI/PLC	Human Machine Interface/ Programmable Logic Controller
HV-GB	Happy Valley-Goose Bay
IDC	Interest During Construction
IPP	Independent Power Producer
IRAC	Prince Edward Island Regulatory and Appeals Commission
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt-Hour
LIS	Labrador Interconnected System

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

LNG	Liquid Natural Gas
LOLE	Loss of Load Expectation
MSH	Mary's Harbour (generating station)
MPUB	Manitoba – The Public Utilities Board
MW	Megawatt
MWh	Megawatt-Hour
N-1	Single Unit Contingency
N-2	Double Unit Contingency
NBEUB	New Brunswick Energy and Utilities Board
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NLH	Newfoundland and Labrador Hydro
NPC	Net Present Cost
NSUARB	Nova Scotia and Review Board
PHS	Port Hope Simpson (generating station)
PPA	Power Purchase Agreement
PUB	Newfoundland and Labrador Board of Commissioners of Public Utilities
PV	Photovoltaic
OEB	Ontario Energy Board
O&M	Operations and Maintenance
SLE	St. Lewis (generating station)
Régie	Régie de l'énergie
ULE	Upgrade Life Extension

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1 INTRODUCTION AND BACKGROUND

1.1 Background

Midgard Consulting Inc. ("Midgard") is pleased to submit this Integrated Resource Plan ("IRP") to Newfoundland and Labrador Hydro ("NLH") for the supply of electrical service to six remote communities on the southern Labrador coast.

NLH is the Crown-owned regulated electric utility for Newfoundland and Labrador. Its service area includes interconnected areas on the island of Newfoundland as well as the Labrador Interconnected System. It also serves 4,500 isolated customers (900 on the island and 3,600 in Labrador)[1] , predominantly with fixed diesel gensets, although in some communities, diesel generation is partly displaced with renewable resources.

This IRP analyzes and recommends a preferred resource and supply configuration to meet the electrical needs of the isolated Southern Coast of Labrador communities of Charlottetown ("CHT"), Port Hope Simpson ("PHS"), Mary's Harbour ("MSH"), and St. Lewis ("SLE"), each of which is currently configured as an isolated micro-grid supplied primarily by NLH owned and operated diesel generation. Two other communities, Pinsent's Arm and Lodge Bay are each served by the MSH and CHT microgrid respectively. MSH integrates some renewable resources which partially offset NLH diesel generation with production from a run of river mini-hydro plant with a combination solar and battery storage facility, which is delivered under the terms of a non-firm Power Purchase Agreement ("PPA").

In October 2019, the CHT Diesel Generating facility experienced a fire which destroyed the three diesel gensets located inside the facility. This incident created a supply gap for CHT which has since been met with mobile, trailer mount diesel gensets – a temporary solution that is inconsistent with NLH reliability standards. This solution has resulted in an alternator failure and two mobile genset fires, the most recent of which was caused by a failure of the cooling system at low temperatures.

NLH had been investigating alternatives for the southern Labrador region, and the loss of the CHT Diesel Generating facility accelerated an application with the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") on July 16, 2021, to reconfigure electricity supply to these six communities. While several configurations were investigated NLH determined the following to be the most economically feasible plan:

[1] Reference: https://nlhydro.com/operations/ (Sourced February 22, 2023)

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1. Interconnect the six communities into a single 25 kV supply network;
2. Develop a central diesel generating station to house adequate firm supply for all six communities[2];
3. Stage the addition of the new gensets to the central generating station to coincide with the existing equipment end-of-life.

The gaps identified by the Board in its correspondence, included insufficient analysis of alternatives, lack of analysis related to diesel generating station replacement and back up generation, and the failure to adequately address the potential impacts of climate change policy and technological change. In response to the concerns raised, the PUB instructed NLH to prepare an integrated resource plan for the six isolated communities that incorporates the following considerations:

1. Assessment of all reasonable options for the provision of service in the region, including how the long-term supply for each of the communities should be addressed in the context of issues related to supply in Labrador generally. The information to be provided should include analysis with respect to reliability, including the potential need for back-up generation, and the timing and costs of replacing or removing the existing diesel generating stations.
2. Exploration of Industrial customer expansion plans in Labrador as necessary to identify the potential impacts on the long-term supply for southern Labrador.
3. Further assessment of the impact of the proposals with respect to the rates and rate structures in Labrador, including the rural deficit, as appropriate.
4. Additional analysis and information to clearly address the uncertainties around load growth, project phases, technology innovation, and other risks including the cost of carbon and diesel fuel cost; in particular the potential impact of climate change policy and technology change should be addressed, including the timelines for the integration of alternative energy sources and the potential options for alternative energy.
5. Indigenous involvement, participation, and ownership of renewable projects.
6. Community-led projects.
7. Review of how similar projects are considered and executed in other, similar jurisdictions.
8. Given the significant uncertainties, the additional information should address alternatives which involve incremental approaches to allow flexibility in development of solutions to address changing circumstances; and
9. Comprehensive sensitivity analysis as to all reasonably foreseeable scenarios.[3]

---

[2] Note: Note: It was concluded that diesel generation remained the most economical generation technology for these remote communities

[3] Reference: Board of Commissioners of Public Utilities, Re: Newfoundland and Labrador Hydro - 2021 Capital Budget Supplemental Application Approval of the Construction of Phase 1 of Hydro's Long-term Supply Plan for Southern Labrador - To NLH - Further Information Required Before Schedule is Resumed.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

This IRP adheres to the PUB's instructions, including re-examination of the original alternatives proposed by NLH, as well as review and analysis of additional alternatives to address interventions raised in response to the original application.

NLH is regulated by the PUB to ensure that the rates it charges are just and reasonable and that the service provided is safe and reliable.[4] This IRP assesses alternative resource supply options in a manner consistent with the Newfoundland and Labrador Electrical Power Control Act ("EPCA") which states:

> *"It is declared to be the policy of the province that all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service."*[5]

For the purposes of this IRP, this mandate is split into two separate considerations:

1. Safe and Reliable – the proposed alternative must be demonstrated to be a safe and reliable source of electricity, taking into account good utility practice reliability metrics, which defines service adequacy at a high level; and
2. Least Cost – the proposed alternatives must be demonstrated to be least cost method of providing adequate service.

This IRP evaluates the technical adequacy of different supply resource alternatives and portfolios by determining if they satisfy the two primary parameters that define resource adequacy:

1. Capacity, which measures the utility's ability to instantaneously supply sufficient power, typically expressed in terms of Kilowatt ("kW") or Megawatt ("MW"), to serve forecast peak demand (electricity is the ultimate "just in time" product, as failure to respond to demand changes within seconds or milliseconds can trigger system instability).
2. Energy, which measures the utility's ability to supply adequate power to serve demand over an extended period to serve the energy needs of the connected loads. Energy is the product of power and time (or more precisely, the integral over time of power), which is typically expressed in terms of Kilowatt-hour ("kWh"), Megawatt-Hour ("MWh") or Gigawatt-Hour ("GWh").

To provide reliable supply, utility operators must plan to have adequate generation capacity available to serve all connected loads at all times, even with the single largest resource unavailable, and they must also have sufficient energy (fuel) readily available to ensure that the generation capacity can continue to serve

[4] Reference: Newfoundland and Labrador Board of Commissioners of Public Utilities, Mandate and Line of Business, retrieved: http://www.pub.nl.ca/mandate.php, on February 13, 2023. These considerations are generally consistent with the expectations of regulators in other jurisdictions across Canada.

[5] Reference: N&L EPCA Section 3.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

loads until more fuel arrives. In the case of a storage hydro plant, the plant capacity is the sum of the individual unit ratings (adjusted for head variability), and the energy is the amount of water in the reservoir, allowing for replenishment via inflowing streams. Similarly, for a diesel plant, plant capacity is the sum of the genset nameplate ratings, and plant energy is the amount of fuel that can be stored between refueling.

On a system basis, Firm planning capacity typically allows for a single unit contingency ("N-1"), in which the largest unit is assumed to be out of service at the time of peak demand. This consideration is an important economic driver when considering integration of isolated systems, since for integrated systems only the largest unit on the entire system is assumed to be out of service during the interconnected system peak, whereas for a group of isolated systems, each individual source of generation must maintain its own standalone N-1 resource redundancy for its own peak (each island may peak at a different time than its neighbours).

Because the communities under study in this IRP are served by non-integrated electrical systems, they cannot rely on neighbouring systems for either energy or capacity, so NLH must maintain standalone local redundant supply resources to serve each of these islanded load centres.

In addition to the above goals, utilities are also expected to be socially and environmentally responsible, which involves managing risks and minimizing negative impacts on the environment. There is significant support for reducing Greenhouse Gas ("GHG") emissions caused by electricity generation, and consequently this IRP evaluates opportunities to increase the renewable proportion of energy generation, acknowledging existing technical constraints and anticipated developments, and also in consideration of Provincial and national policies.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

2 REPORT OUTLINE

This IRP is structured to enable evaluation of a broad range of practical resource alternatives and system configurations, with the goal of determining a preferred resource portfolio and system configuration that will best enable NLH to satisfy its regulated mandate of providing least cost reliable and safe electrical service to the isolated Southern Labrador Coast communities.

Section 3 of this IRP explores the regulatory context in which NLH operates. The regulatory context includes the Provincial regulations which grant NLH its authority to serve and set out the mechanisms by which it is measured. The Provincial regulatory environment in Newfoundland and Labrador is similar to that of many other Canadian jurisdictions, wherein a Provincial Crown Corporation is authorized to serve its electrical customers under the guidance of an independent regulatory board tasked with review and approval of the utility's rates, capital investments and operational spending.

In addition to its adherence to directly applicable Provincial utility and electricity regulations, NLH is also influenced by evolving federal policies. While these policies may have less impact on NLH's day to day business operations, the federal government can influence NLH decisions through specific regulatory matters over which it has authority (e.g., fisheries, navigable waters, transportation, communications). It also has significant influence as a result of programs and incentives available to NLH or independent resource developers including Indigenous development agencies.

Section 4 of this IRP summarizes the baseline conditions against which the integrated resource plan is evaluated. This includes an assessment of current and forecast loads for the subject communities and a description of NLH's current system configuration in the region, which includes details on the current age and expected remaining useful life of the existing assets.

The difference between the forecast loads and the ability of the existing isolated NLH community systems to supply both energy and capacity to serve those forecast loads defines the supply gaps against which planned resource portfolio alternatives are evaluated.

Section 4 also introduces and evaluates the potential to interconnect the four isolated Southern Labrador community load centres into a single system.

Section 5 presents a high-level resource option assessment based on un-timed technology-specific generation resources. These resources are screened in terms of their technological maturity and whether commercial equipment is presently available for purchase and deployment.

Section 6 presents an assessment of energy resources that by themselves are incapable of providing Firm capacity to the system. This section evaluates standalone renewable energy resources and hybrid systems that incorporate both renewable resources and onsite battery storage.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Section 7 compiles the technologies that pass through the Section 5 and 6 preliminary screening into a series of technically viable supply scenarios capable of reliably serving NLH's forecast peak demand and energy usage. The supply alternatives include timing and phasing the technology-specific resource replacements needed to serve each of the four systems in isolation, as well as resources that could be integrated into in a combined portfolio to serve all six communities via a regional 25 kV interconnected system. These alternatives are assessed and ranked economically according to Net Present Cost ("NPC") using site-specific[6] capital cost estimates. The ranked alternatives are further assessed for operational practicality, and a final recommended approach is proposed.

Section 7 also presents a high-level analysis of GHG emissions and the implied cost per tonne of saved emissions for those renewable alternatives that carry a higher cost than a reliable thermal based system.

Section 8 presents a sensitivity analysis to test if the scenario evaluation conclusions are robust in the face of future uncertainties, including potential variations in capital cost, operating cost, fuel cost, and NLH's regulated cost of capital.

Section 0 presents the IRP conclusions and recommendations.

[6] Class 5 capital cost estimates have been used for consistency with the previous PUB filing.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

3 NLH REGULATORY ENVIRONMENT

3.1 Background

NLH is a Provincial Crown electric utility regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") to ensure that the rates it charges are just and reasonable and that the service provided is safe and reliable.[7] NLH is mandated to evaluate alternative resource supply options in a manner consistent with these two primary considerations:

1. Safe and Reliable – the proposed resource portfolio must provide a safe and reliable source of electricity, which defines service adequacy for the purpose of supply resource analysis.
2. Least Cost – the proposed resource portfolio must be demonstrated to be least cost method of providing adequate service.

NLH's planning process is directly governed by mandatory requirements set out in Provincial legislation and regulations. NLH's strategic goals can also be expected to align with government policies as a Provincial Crown utility.

Under Canada's constitution and the Newfoundland Act, the jurisdiction for management of natural resources rests with the Province of Newfoundland and Labrador, although there remains some jurisdictional intersection between Provincial and federal authority in respect of some NLH activities, due to Federal policies and legislation such as the Indian Act and the Fisheries Act. More recently, the Greenhouse Gas Pollution Pricing Act (2018), federal legislation that imposes a federal price on carbon emissions in the absence of the sufficiently stringent provincial price, has added another potential area of federal authority over NLH's operations.

Beyond its legislative powers, the federal government is also able to exert significant influence on energy resource development activities across the country through financial incentives and supports.

In addition to Provincial and federal legislation and policy, NLH is influenced by direct input from interested parties such as ratepayers, local communities, stakeholders, and Indigenous groups. These interested parties often hold a broad range of competing and difficult to quantify opinions, aspirations and goals which may bear on resource planning decisions. Ultimately, NLH must satisfy its core mandate of achieving least cost reliable supply, after which it may consider resource planning alternatives that address these competing influences.

[7] Reference: Newfoundland and Labrador Board of Commissioners of Public Utilities, Mandate and Line of Business, retrieved: http://www.pub.nl.ca/mandate.php, on February 13, 2023.

The remainder of this section explores in more detail the regulatory context in which NLH conducts its resource planning. The section also includes a jurisdictional scan of other Canadian utilities that serve remote non-integrated loads to provide a broader context for considering NLH's viable resource options.

3.2 Provincial Context

NLH is one of two electric utilities in the Province of Newfoundland and Labrador regulated by the PUB to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable.

Provincial legislation that governs how NLH plans and operates its electrical system includes:

1. The Public Utilities Act (1990);
2. The Electrical Power Control Act (1994);
3. The Hydro Corporation Act (2007); and
4. Management of Greenhouse Gas Act (2018)

Aside from the legislation listed above, the Newfoundland and Labrador government has also issued a Renewable Energy Plan (2021), which provides strategic goals for the Province to transition toward renewable energy generation resources.

In addition, there is the Northern Strategic Plan and a number of Orders in council that direct specific rates and subsidies for the Labrador region. These regulations provide additional subsidies, but they do not impact the findings of this IRP.

3.2.1 Relevant Provincial Legislation

NLH's operations and planning activities are regulated by the PUB to adhere to Provincial legislation including the Electrical Power Control Act ("EPCA"). Several relevant clauses of the EPCA Power Policy Section 3[8] have been extracted into Table 1 below, with commentary setting out how the Power Policy priorities in the EPCA have been interpreted for application in the resource evaluations done in this IRP.

[8] Reference: Newfoundland and Labrador, Electrical Power Control Act, 1994, https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 1: Relevant EPCA Power Policy Section Excerpts

Section	Policy Language	Interpretation
3(b)	It is declared to be the policy of the province that all sources and facilities for the production, transmission, and distribution of power in the province should be managed and operated in a manner…	Preamble
(ii)	…that would result in consumers in the province having equitable access to an adequate supply of power.	NLH is obligated to deliver reliable service to its customers to satisfy all demand.
(iii)	…that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service.	NLH is obligated to plan, construct, and operate its system in a reliable manner at the lowest cost. Reliability is interpreted to have priority because unfulfilled service is meaningless even at lowest cost.
(i)	…that would result in the most efficient production, transmission, and distribution of power.	To the extent that NLH is meeting its obligations to serve in a reliable and least cost manner, it must also strive to achieve operational efficiencies in the planning and operation of its system.
(v)	…should promote the development of industrial activity in Labrador.	Decisions that will promote industrial economic development in Labrador are preferred as long as the above priorities are satisfied.
3(f)	It is declared to be the policy of the province that planning for future power supply of the province shall not include nuclear power.	NLH may not plan or adopt nascent Small Nuclear Reactor technology to meet customer load.

3.2.2 Other Relevant Provincial Policy

The Province of Newfoundland & Labrador released "Maximizing our Renewable Future – A plan for Development of the Renewable Energy Industry in Newfoundland and Labrador (Renewable Energy Plan)" in 2021.[9] The plan aims to reduce provincial GHG emissions by 30% below 2005 levels by 2030 and adopts a regional target to further reduce GHG emissions by 35-45% below the 1990 regional GHG emissions level by 2030.[10]

[9] Reference: https://www.gov.nl.ca/iet/files/Renewable-Energy-Plan-Final.pdf

[10] Reference: NEGECP-Statement-Post-Conference-May-17-2021_English.pdf (cap-cpma.ca)

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

To achieve these goals and to provide direction for the Province to adopt further renewable energy penetration into its energy sector in the coming decade, the plan outlines the following areas of consideration for review:

1. Review the provisions of the Electrical Power Control Act of 1994.
2. Review the electricity and renewable energy regulatory framework of relevant and leading jurisdictions.
3. Review the province's net metering programs.
4. Explore advancing the government's policy approach to renewable energy.
5. Explore regulatory framework options for foreseeable renewable energy development scenarios.
6. Continue to work with the government of Canada regarding relevant regulation and policy.
7. The Department of Industry, Energy, and Technology will review the provinces legislation, regulation, and policies where possible in enabling renewable energy development.

Of specific relevance to this IRP, the plan includes the following goals for remote isolated communities:

1. Complete a feasibility study on increasing the use of high efficiency woodstoves.
2. Pursue renewable energy development supporting Indigenous involvement and community led projects.
3. Create an Independent Power Producer Policy.
4. Encourage renewable energy projects and support NLH to address challenges related to 'minimum load variation'.
5. Pursue renewable energy development and maximize opportunities for Indigenous led and owned projects.

These policies and goals are all future-dated, and though they may inform NLH's supply decisions in the near term, they do not relieve NLH from its core legislated mandate of providing reliable service at least cost. Out of necessity NLH has been forced to use temporary portable gensets to supply two of the four isolated systems. Further delay in implementing a safe reliable permanent solution in anticipation of potential future policy changes could be considered inconsistent with prudent utility practice.

Specifically, a future goal of increased renewable penetration does not override prevailing legislation which prioritizes reliability and fiscal prudence. Reliability and least cost are explicit legal mandates for NLH.

3.2.3 NLH Strategic Plan

In addition to its role as a regulated utility operating within a legislated mandate, NLH's strategic direction is also influenced by Provincial priorities and policies that are not legislated. NLH's 2023-2025 Strategic Plan,

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

summarized in Table 2, sets eleven (11) goals intended to promote Provincial governmental priorities while also fulfilling NLH's legislated mandates.[11]

Table 2: NLH's Goals for Strategic Plan 2023-2025

#	Goal
1	Revitalize Our Organization
2	Deliver Reliable Electricity to Our Customers at the Lowest Possible Cost
3	Recognize Indigenous History and Strengthen Indigenous Relationships
4	Engage Who We Serve
5	Continue to Prioritize the Safety and Health of our Employees
6	Foster Proud and Engaged Teams
7	Anticipate and Develop Our Workforce Requirements
8	Support Growth of Renewable Energy Supply
9	Advance Electrification and Demand Management
10	Optimize the Value of Provincial Energy Resources
11	Integrate Renewable Energy Resources in Local Communities

The second of these goals is derived directly from NLH's legislated mandate. Other goals with specific relevance to this IRP include #3, #4, #8, #9 and #11 – these are treated in the IRP as resource alternative evaluation priorities to the extent they do not conflict with NLH's primary legislated mandate.

3.3 Federal Context

Historically and constitutionally, except for specific areas of federal jurisdiction, the federal government has a limited direct role in natural resource management in Canada. The federal jurisdictional powers that directly impinge on natural resource development activities are largely constrained to four specific Federal Acts. Table 3 summarizes those Acts and outlines the conditions that would trigger their applicability to this IRP.

[11] Reference: NLH, Strategic Plan 2023-2025, https://nlhydro.com/about-hydro/our-strategic-goals/

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 3: Applicable Federal Regulatory Acts

Federal Act	Trigger and Applicability to this IRP
Fisheries Act	Impacts on fish or fish habitat. Hydroelectric projects or other developments that disturb fish habitat would likely trigger review under this act.
Indian Act[12]	Development footprint intersecting with federal crown lands held in trust as Indian Reserves Unlikely to be applicable in this IRP.
Canadian Navigable Waters Act	Impacts on navigation and recreation on any of Canada's navigable waterways. Hydroelectric projects could possibly trigger review under this act.
Canadian Environmental Protection Act	Project review would be triggered in the event another Federal Act was triggered or if federal money was used to support resource project(s).

In 2016, Canada entered into the Paris Agreement, an international treaty under which Canada pledged to reduce carbon dioxide by 30% by 2030 compared to 2005 levels.[13]

These commitments made at a federal level present a challenge because of Canada's devolved provincial powers, wherein some provinces may share a disproportionate burden or benefit relative to others. To address this potential disparity, Canada has taken a two-pronged approach to implementing these commitments:

1. First, it enacted the Greenhouse Gas Pollution Pricing Act in 2018 (revised in 2022), which imposes a federal floor price of carbon on jurisdictions that are deemed to have implemented an insufficiently rigorous carbon price of their own.[14]
2. Second, it is using its powers of taxation to provide grants and loans to incentivize and subsidize non-GHG-emitting sources of generation. Applying federal monies to a resource project would thereby trigger review under the aforementioned Canada Environmental Protection Act.

The second of these paths is exemplified by federal programs that have been created to subsidize and encourage development of new renewable generation, particularly in remote and Indigenous communities. Examples of these programs are summarized in Table 4.

[12] Note: The original 1949 Newfoundland Act, which was the instrument by which Newfoundland and Labrador joined the Canadian confederation, omitted explicit reference to Newfoundland and Labrador's Indigenous peoples.

[13] Note: Canada has subsequently set further goals to reduce its nationally determined GHG emissions to 40-45% below 2005 levels by 2030. Reference: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/plan/overview.html

[14] While this could be construed as an intrusion into Provincial areas of jurisdiction, a reference case heard by the Supreme Court of Canada confirmed the Act as constitutional in a 6-3 ruling under the "peace, order and good government" clause of the Constitution by finding that Global Warming constituted a genuine national concern beyond provincial boundaries.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 4: Federal Economic Incentive Programs

Federal Government Renewable Energy Funding Programs
Smart Renewables Electrification Pathways Program (Currently not accepting new applications) is an extension of Canada's Emission Reduction Plan which provides up to $1.564 billion over 8 years for smart renewable energy and electrical grid modernization projects. The program encourages the replacement of fossil-fuel generated electricity with renewables that can provide essential grid services while supporting Canada's equitable transition to an electrified economy.[15] The maximum funding available is $25 million per project and there are two guides for application of generation and storage projects and grid modernization projects, including utility-led energy storage projects. Eligible recipients are the owners of eligible projects. Recipients may include: 1. Legal entities validly incorporated or registered in Canada; 2. Provincial, territorial, regional, and municipal governments and their departments and agencies; 3. Indigenous communities and governments, Tribal Councils, National and regional Indigenous councils or organization, and Indigenous for-profit and not-for-profit organizations. Not all project components are available for funding. Further details can be found at: https://www.nrcan.gc.ca/climate-change/green-infrastructure-programs/sreps/generation-and-storage-applicant-guide-smart-renewables-and-electrification-pathways/24689
Clean Energy for Rural and Remote Communities Program - $300 million available through 2027 for Indigenous, rural, and remote communities. The program's goal is to reduce the use of fossil fuels for heating and electricity by increasing the use of local renewable energy sources and energy efficiency.[16] This program is available to: 1. First Nations, Inuit and Métis communities, governments, development corporations and organizations; 2. Canadian businesses and not-for-profit organizations; and 3. Provincial, territorial, regional, or municipal government organizations.
Indigenous Off-Diesel initiative - Program provides clean energy training and funding to support Indigenous-led climate solutions in remote Indigenous communities that currently use diesel or other fossil fuels for heat and power.[17] The initiative provides up to $1,525,000 in funding for community clean energy training, planning and projects. 1. $25k – Complete clean energy training through the 20/20 Catalysts program; 2. $500k – Funding and resources for community engagement, training, team salaries, and clean energy planning; 3. $1M – Champion teams lead their communities in planning and implementing community-scale clean energy and energy efficiency projects. To participate in the initiative participants must either participate in the upcoming 20/20 Catalysts program from April-July 2023, or have already completed the program. Applications are open to individuals and teams from remote Indigenous communities. Priority will be given to communities that do not already have federal funding for community-scale clean energy or energy efficiency projects.[18]

[15] Reference: https://www.nrcan.gc.ca/climate-change/green-infrastructure-programs/sreps/23566

[16] Reference: https://www.nrcan.gc.ca/reducingdiesel/clean-energy-for-rural-and-remote-communities-funded-projects/22524

[17] Reference: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reduce-emissions/reducing-reliance-diesel/indigenous-off-diesel-initiative-cohort-2-2022-2023.html

[18] Reference: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reduce-emissions/reducing-reliance-diesel/indigenous-off-diesel-initiative-cohort-2-2022-2023.html#participation

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Federal Government Renewable Energy Funding Programs
Community Opportunity Readiness Program - Provides project-based funding for First Nation and Inuit Communities for a range of activities to support communities' pursuit of economic opportunities.[19] The program can supply up to 66.67% of the project funding up to $3M, which includes the following noteworthy areas: electrical, energy systems, fuel storage and distribution systems. Further details are outlined at: https://www.sac-isc.gc.ca/eng/1100100033417/1613659339457#sec3

Relevant enhancements under the Canadian Environmental Protection Act include promulgation of the Clean Electricity Regulations ("CER").[20] Formerly known as the Clean Energy Standard, these regulations are currently in a final round of revision. Their objective is to encourage greater electrification in transportation and heating, combined with further development of transmission infrastructure to enable to Canada achieve a net-zero emissions grid by 2035.

NLH's remote service areas in Labrador are exempt from the CER, as the enhanced regulations do not apply to diesel generators operating in areas not connected to an electricity system regulated by the North American Electric Reliability Corporation ("NERC").[21]

Based on review of the federal regulatory context, it is concluded that there are no federal regulations that materially directly impact resource options considered in this IRP. However, the regulatory environmental is clearly in flux. The most likely potential future impact would be the removal of the current carbon price exemption for remote, non-interconnected diesel generators. This potential impact will be considered in Section 8.

The economic incentives on offer from the Federal government could help offset cost-of-supply for some IRP resource options, either for new NLH-owned generation, or for projects developed by Independent Power Producers ("IPP") which under current federal and provincial policies often include Indigenous and local community supply partners. These potential resource cost offsets are considered in this IRP.

3.4 Other Canadian Jurisdictions

The electricity regulatory and technological landscape across Canada is in flux. A strong focus on both electrification and transitioning to non-emitting sources of generation, coupled with ongoing advances in renewable generation and storage technologies warrants review of other jurisdictions across the country.

It is important to note that in the regulatory context that NLH operates in, the Electrical Power Control Act states "in carrying out its duties and exercising its powers under this Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in Section 3, and in doing so shall apply tests

[19] Reference: https://www.sac-isc.gc.ca/eng/1100100033417/1613659339457#sec1

[20] Reference: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html

[21] https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

which are consistent with generally accepted sound public utility practice". As a result, it is critical that NLH understands the context in which other similar utilities operate so that they can be aligned with these practices. This review did not include Alberta because its open and largely investor-owned electric utility market structure is dissimilar to NLH's. The Maritime provinces (New Brunswick, Nova Scotia, and Prince Edward Island) were also excluded from this investigation because they have no communities isolated from the respective provincial grids.

Table 5 summarizes the various regulated jurisdictions in Canada and their respective regulatory bodies.

Table 5: Jurisdictional Scan – Overview of Jurisdictional Regulators

Jurisdiction	Provincial / Territorial Utility Regulatory Board
BC	British Columbia Utilities Commission ("BCUC")
AB	Alberta Utilities Commission ("AUC")
SK	Crown Investments Corporation ("CIC")
MT	Manitoba - The Public Utilities Board ("MPUB")
ON	Ontario Energy Board ("OEB")
QC	Régie de l'énergie ("Régie")
NB	New Brunswick Energy and Utilities Board ("NBEUB")
PEI	Prince Edward Island Regulatory and Appeals Commission ("IRAC")
NS	Nova Scotia Utility and Review Board ("NSUARB")
YK	Yukon Utilities Board
NWT	Northwest Territories Public Utilities Board
NU	Nunavut has an advisory council reporting directly to the Minister responsible for Qulliq Energy Corporation

Each Canadian province or territory has established jurisdictional renewable energy targets, and each jurisdiction is at a different stage in moving towards increased renewable penetration and reduced diesel generation. The following points summarize where each province currently stands in promoting renewable resources through policy statements, regulations and/or legislation.

1. In British Columbia the Clean Energy Act is legislation set the goal to generate 93 % of BC's electricity from clean or renewable electricity. The CleanBC Roadmap to 2030 documents the province's policy to meet emissions reduction targets in 2030 and 2050.
2. Alberta's primary clean energy legislation is the Renewable Electricity Act, which calls for 30% of all electricity in the province to come from renewables by 2030. The province has been successful in attracting renewable investment into the province because of ESG (environmental, social and governance) and emissions reductions goals that have become more important to investors.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

3. Saskatchewan's Environmental Assessment Act provides the legislative framework for renewable energy projects.
4. Manitoba is currently evaluating options to replace diesel generation with renewable energy projects in its remote communities, while also developing energy policies to address emerging trends and transform to a low carbon economy. Manitoba's Clean Energy Strategy documents the province's clean energy policy, and applicable legislation includes The Affordable Utility Rate Accountability Act, The Climate Change and Emissions Reduction Act and The Energy Savings Act.
5. Ontario has moved towards a competitive bidding process that does not favour any single type of generation over another. Ontario published its Long-Term Energy Plan in 2017 to set out the province's clean energy policies. Relevant provincial legislation includes the Fair Hydro Act and the Climate Change Mitigation and Low-Carbon Economy Act.
6. Quebec released its clean energy policy in 2020 entitled "2030 Plan for a Green Economy".
7. Yukon has implemented the Clean Energy Act as legislation to commit to its greenhouse gas commitments. The Territory's climate change policy set out in "Our Clean Future – A Yukon strategy for climate change, energy and a green economy".
8. Northwest Territories released its 2030 Energy Action Plan as the territory's climate policy. The main objective is to reduce GHG emissions from electricity generation in diesel communities by 25% and to increase renewable energy used for community heat to 40% by 2030.
9. The Nunavut Government has released its Renewable Energy Support Policy which outlines the territory's renewable energy strategy. Qulliq Energy in Nunavut is attempting to develop additional renewable resources but given existing capital constraints the territory is challenged in making the economics of renewable energy projects viable. Further support is required from the Federal and Territorial governments to move the territory away from diesel generation.[22]

Few Canadian jurisdictions have enacted legislation to impose direct control on the supply resource decisions of regulated utilities. Plans, strategies, and policy statements made by the respective Provinces and Territories mostly remain just that, and most Canadian jurisdictions have not yet replaced or updated the legislation that governs the respective regulatory bodies, or the supply resource decisions made by the respective regulated utilities.

Further, most Provincial and Territorial renewable policies primarily address the respective integrated provincial and territorial electrical systems, and do not single out the remote non-integrated systems that serve only a small portion of the population in most of these jurisdictions.

[22] Reference: https://www.qec.nu.ca/sites/default/files/alternative_energy_report_final_4mar_eng_0.pdf

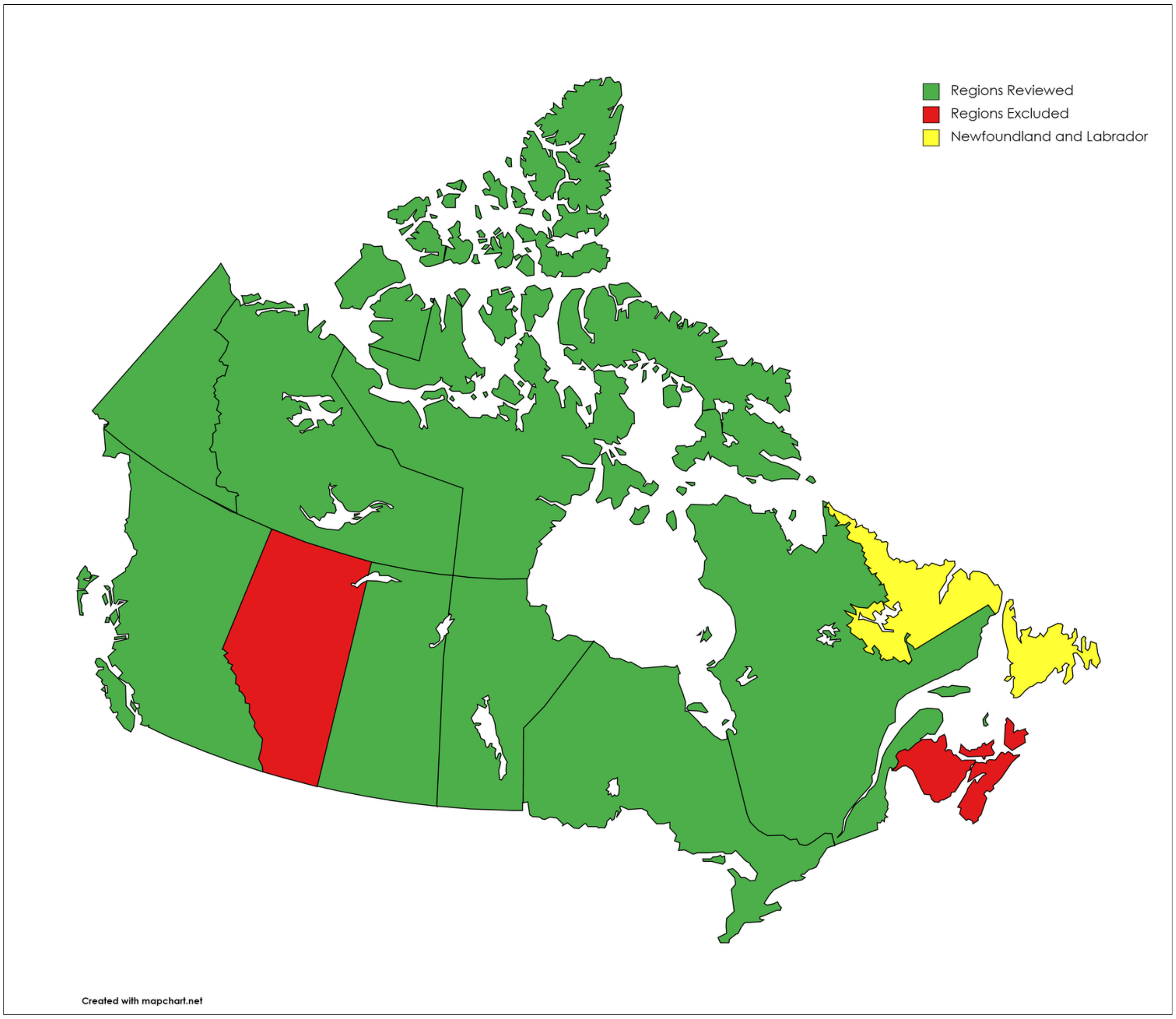
MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

A further review was done of all provinces and territories with significant numbers of isolated system communities. The reviewed and excluded provinces and territories are shown in Figure 1 below.

Figure 1: Reviewed Canadian Jurisdictions (Provinces/Territory)



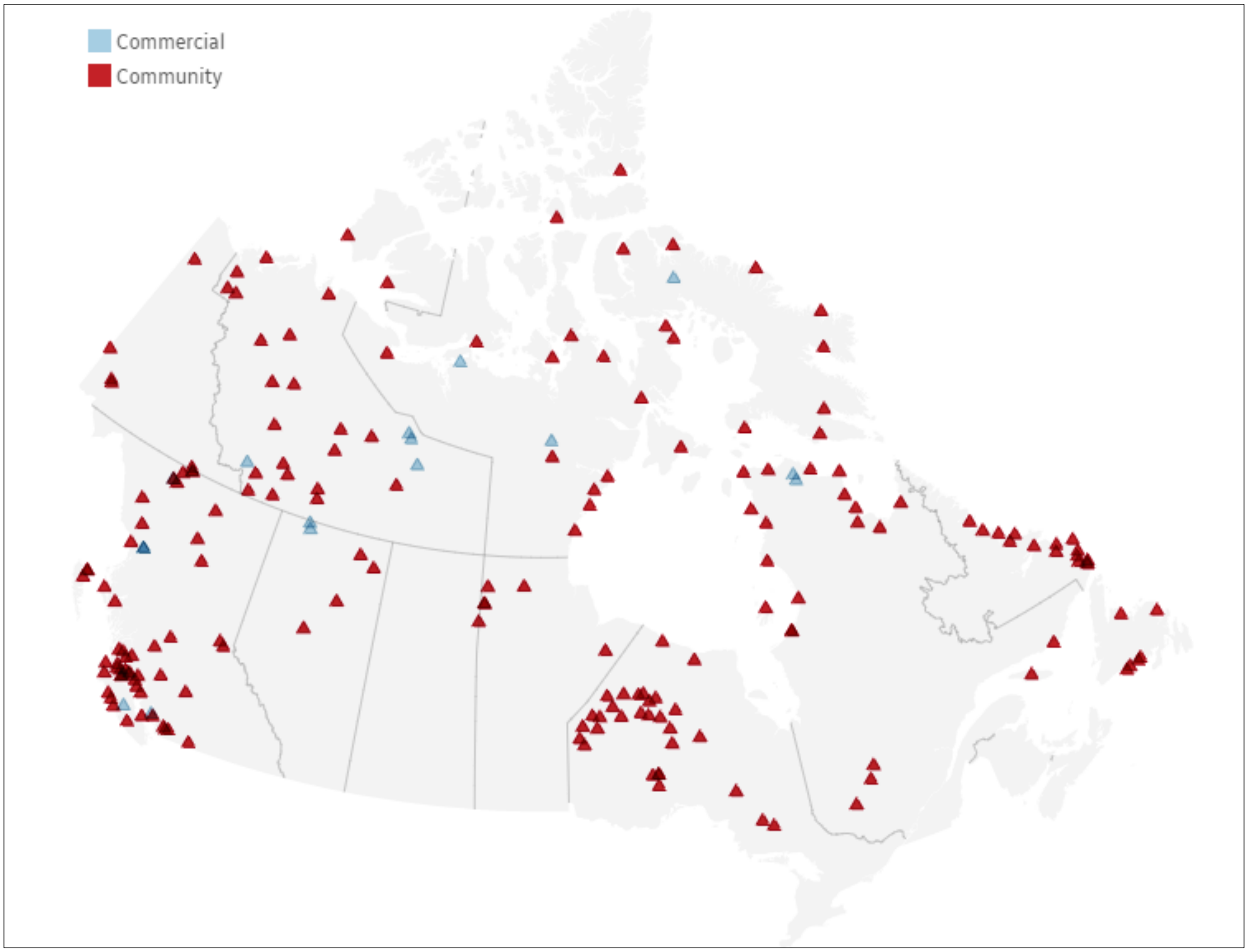
MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Figure 2 shows the locations of Canada's "off-grid" communities and industrial sites that are supplied by diesel generation. More than 200 Canadian remote communities are not connected to a regional grid, and most of these isolated communities rely on diesel generation for electrical power.

Figure 2: Diesel Powered Remote Communities and Commercial Sites in Canada[23]



There are three common themes observed across most of the reviewed Canadian jurisdictions:

1. Almost every utility's mandate included a variation of "reliability" and "lowest cost". While many jurisdictions have aspirational environmental considerations, most do not mandate that utilities must implement renewable or low carbon technologies to serve isolated communities.
2. Renewable energy sources implemented to serve isolated communities must be cost competitive with the diesel alternative (including the cost to transport diesel fuel and any associated carbon tax).

[23] Reference: Natural Resources Canada, 2018 data, CBC News, retrieved from https://www.cbc.ca/newsinteractives/features/diesel-solar-wind-electricity-remote-Iqaluit-QEC-NNC, on December 5th, 2022.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

3. Most utilities will enter into agreements with independent developers (including First Nations) to purchase energy if doing so is cost competitive. For projects sited in isolated communities, this is generally interpreted as being competitive with the cost of diesel generation.
4. Most jurisdictions are legally mandated to provide reliable power at least cost. As a result, at present most of the remote communities in Canada are fully supplied, partially supplied, or backed-up by diesel generation, since it is very reliable (typical gensets have 95% or better annual uptime when appropriately maintained) and dispatchable to accommodate load variations.
5. While there are some remote communities that have displaced all or most diesel fuel generated energy with renewable resources, in almost all cases redundant diesel generation is maintained to provide dependable backup generation.
6. Most of the renewable projects developed in remote communities have been developed by third parties, including local First Nations or Indigenous peoples, under power purchase agreements ("PPA's") with unit energy prices typically capped by the cost of a diesel alternative.
7. The overwhelming majority of remote community generation throughout Canada continues to be provided by diesel generation because it remains the technically and economically appropriate power supply solution for most isolated communities.

3.5 Regulatory Environment - Conclusions

NLH's resource planning activities continue to be primarily governed by the Electrical Power Control Act – its resource planning decisions must first and foremost be consistent with the Act. Resource alternatives that satisfy the requirements of the Act can then be evaluated against the Strategic Goals set out in NLH's 2023-25 Strategic Plan.

Current Federal legislation has limited applicability to Provincial resource planning for isolated community systems, and most of the risks attributable to possible future federal legislation changes can be adequately addressed by appropriately accounting for the cost of carbon emissions when modelling the fuel costs of different resource alternatives.

Federal funding programs offer incentives to deploy renewable resources, but most of these programs have a dual mandate of supporting both renewable technology development and supporting economic development for Canada's First Nations and Indigenous Peoples. Indigenous developers operating in the Southern Labrador region are therefore potentially well-positioned to become economically attractive suppliers of renewable energy to NLH.

Taking these conclusions into account, Table 6 summarizes the regulatory and policy considerations that are used in this IRP to evaluate and prioritize the resource planning options.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1 **Table 6: Policy Conclusions**

Metric	Discussion
Reliable Power	Resource options considered in this IRP must provide the Southern Labrador communities with appropriately reliable service, consistent with good utility practice by ensuring adequate and consistent generation capability despite the extreme local weather conditions. This objective is based on: 1. NLH Regulatory Mandate of #1 2. NLH Strategic Goal #2
Lowest Possible Cost consistent with Reliable Service	Resource options considered preferred in this IRP must deliver electricity to the Southern Labrador region at the lowest possible cost by making measured and responsible capital investment decisions that minimize long-term power supply costs and pace the magnitude and timing of electricity rate increases. This objective is based on: 1. NLH Regulatory Mandate #2 2. NLH Strategic Goal #2
Renewable Energy Development	Cost competitive renewable resource options that are either in and of themselves reliable, or that are complementary when integrated into a reliable system are considered in the IRP to be preferrable to non-renewable resources. This objective aims to meet: 1. NLH Strategic Goals #8, 9, and 11
Community Engagement	Options that enable the involvement of local and Indigenous communities in the planning, control, operation, and ownership of electrical infrastructure are preferred. This objective aims to meet: 1. NLH Strategic Goals #3, 4, and 11

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

4 EXISTING AND FORECAST REGIONAL LOADS AND GENERATION RESOURCES

The Southern Labrador region has historically been (and continues to be) sparsely populated, with an economic focus on fisheries. Since the collapse of the Atlantic cod fishery in 1993, the region has refocused on snow crab and shrimp fisheries and its population and industry have remained relatively stable over the last decade. Recent developments include the 2022 paving completion of the Trans-Labrador Highway, Route 510, which passes directly through PHS and MSH and serves all the South Labrador communities studied in this IRP. This road improvement may result in an increase in migration and tourism to the region. The other major recent development in the region was the construction of a salt fish processing facility in MSH, which was completed in 2021.

These communities are served by diesel generation, with a single generating station located in each islanded community. On October 7, 2019, a fire destroyed the diesel generating station in CHT, and temporary mobile diesel gensets were put in place pending a long-term supply solution. Continued operation of mobile gensets through 2023 has resulted in three further mobile equipment failures, one in July 2020 which damaged a genset alternator, a fire in July 2022 which destroyed a 725 kW mobile genset, and a second fire in February of 2023 which caused significant damage to a 910 kW genset. A permanent solution for CHT is needed as soon as possible.

In this IRP, customer load is used to represent the overall power usage of NLH's customers. It comprises both demand, which is the instantaneous usage at any given time (expressed as kW or MW), and energy usage, which is the demand integrated over time (expressed as kWh or MWh). Of particular interest in the planning context is the forecast Peak Demand within a given period, such as annual peak demand or peak demand over the whole planning period. This peak demand establishes the required dependable generation capacity (with a suitable reserve allowance for contingencies) that NLH must maintain.

Energy load can be served either using dependable capacity resources, such as diesel gensets, or by other resources such as intermittent renewable generation, which cannot be relied upon to provide capacity at all times, but which can provide preferred diesel-free energy when available.

4.1 Historic Community Load in Southern Labrador

This section details the residential populations, major industries, and electrical loads of each community.

CHT: This community had a population of 292 in the 2021 census and is also locally interconnected with Pinsent's Arm (population, 43). CHT is home to a shrimp plant operated by Labrador Choice Seafood Ltd. The ten-year historical average annual energy consumption (2012 – 2021) of the combined residential and commercial loads in CHT was 5,205 MWh, ranging from 4,257 MWh to 5,796 MWh.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

MSH: This community had a population of 312 in the 2021 census and is locally interconnected to Lodge Bay (population, 61). MSH is host to a crab processing facility. Over the past ten years MSH's combined residential and commercial loads have consumed an average of 4,493 MWh, ranging from a minimum of 3,875 MWh to a maximum of 4,750 MWh. A salt fish processing facility owned by Labrador Fishermen's Union Shrimp Co. completed construction in 2022. The processing facilities are expected to have a combined operating season running from July to early October, extending the historical processing season by an additional 6 weeks[24]. NLH has been informed that both plants will not operate concurrently, such that the community's peak demand will not increase, although cumulative annual energy consumption will.

PHS: This community had a population of 403 in the 2021 census and its electrical load is primarily residential. The ten-year average annual energy consumption in PHS was 3,419 MWh, ranging from a minimum of 3,089 MWh to a maximum of 3,607 MWh.

SLE: This largely residential community had a population of 181 in the 2021 census. The 10-year average annual energy consumption in SLE was 1,530 MWh, ranging from a minimum of 1,448 MWh to a maximum of 1,609 MWh.

4.1.1 Historic Peak Demand

The most recent full year of monthly peak demand data (2021) provided by NLH is presented below. This data shows that peak demand in the communities of CHT and MSH occurs during the summer processing season of the fish plants, while PHS and SLE have winter peaking loads, as expected with largely residential loads. These loads are listed in Table 7 and shown graphically in Figure 3.

[24] Reference: Labrador company hopes its 410 million bet on salted cod will pay off, Nov. 3, 2021, Source Link: https://www.saltwire.com/atlantic-canada/business/labrador-company-hopes-its-10-million-bet-on-salted-cod-will-pay-off-100653566/

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

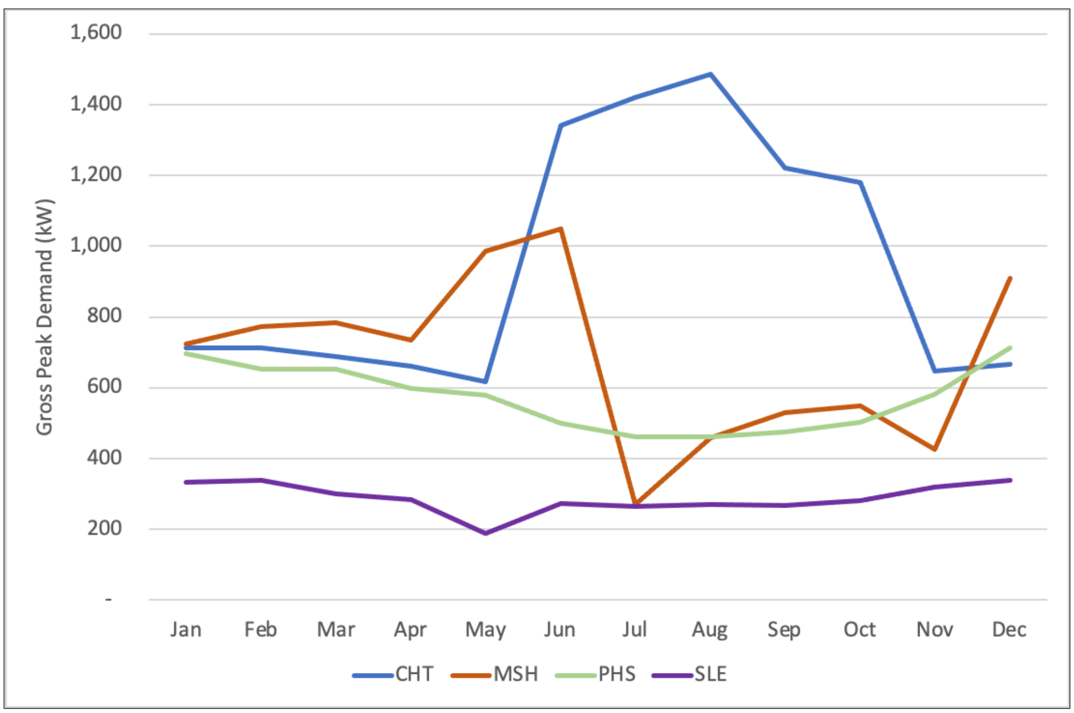
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 7: Southern Labrador Systems Monthly Gross Peak Demand (kW) (2021)

	CHT	MSH	PHS	SLE
January	714	725	696	334
February	712	772	652	338
March	689	784	653	300
April	661	735	597	285
May	618	987	579	189
June	1,340	1,050	499	274
July	1,420	271[A]	462	264
August	1,487	460	462	269
September	1,222	531	474	268
October	1,180	550	502	281
November	646	425	582	319
December	667	910	713	338

A. A reporting error resulted in peak demand being under reported for this month. Annual reported peak demand was 1,050, in June.

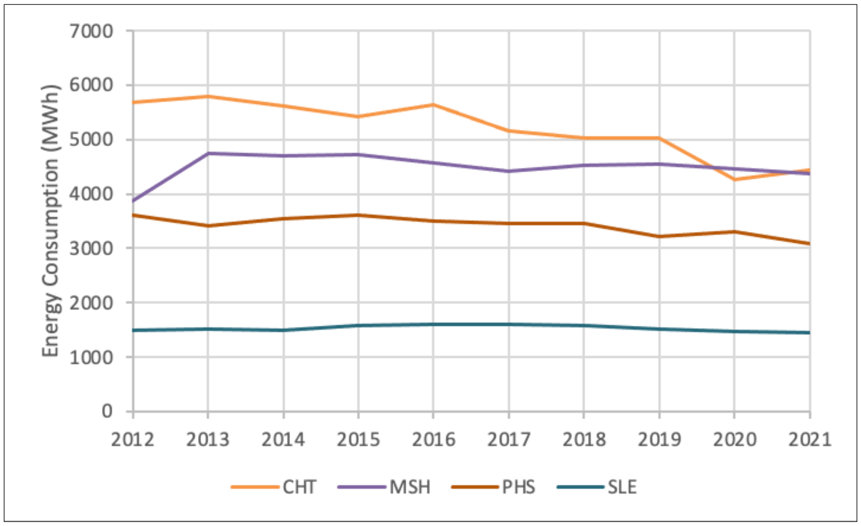
Figure 3: 2021 Monthly Gross Peak Demand for Southern Labrador Systems



4.1.2 Historic Energy Use

Over the past decade, the overall load in the Southern Labrador region has remained relatively stable as shown in Figure 4.

Figure 4: Annual Historical Energy Use in Megawatt Hours (MWh) by Community



4.2 Community Load Forecast

This IRP utilizes NLH's 2022 load forecast, which predicts relatively low overall growth for the region. There has been some recent indication of a potential future customer interconnection request to support a large mining load large west of St. Lewis. For the purposes of this IRP, this indication is considered to be early stage, with many potential years of permitting, development yet to be accomplished before a final investment decision is reached. For the purposes of planning, known and existing loads are considered.

4.2.1 Forecast Peak Demand

The analysis in this IRP utilizes forecast annual peak demand in 2023, 2030, 2035 and 2045 – the latter three years represent the forecast end of useful life for MSH, PHS and SLE, respectively. The forecast peak demand values for these years are summarized in Table 8.

Table 8: Forecast Gross Annual Peak Demand (kW)

	2023	2030	2035	2045
CHT / Pinsent's Arm	1,557	1,649	1,664	1,676
MSH / Lodge Bay	1,177	1,188	1,191	1,195
PHS	753	754	754	754
SLE	384	382	378	371

Note: Forecast annual peak demand includes station service load and system losses – it is a representation of the total generation that is required and not just customer's demand.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

In its earlier filing with the PUB NLH proposed interconnecting the four systems with a 25 kV interconnection. In that event, combined, or coincident loads become relevant. Table 9 shows islanded (non-coincident) and combined (coincident) peak demand forecasts prepared by NLH for a range of 25 kV system interconnection configuration options.

Table 9: Forecast Annual Peak Demand – Interconnection Alternatives (kW)

	2023	2030	2035	2045
Sum of Non-coincident Islanded Peak Demand of all Communities	3,871	3,973	3,987	3,996
Coincident Peak Demand of Communities (All Interconnected)	3,418	3,511	3,524	3,533
(CHT+MSH), PHS & SLE	3,717	3,810	3,822	3,830
(CHT+PHS), MSH & SLE	3,606	3,708	3,722	3,730
(CHT+PHS+MSH) & SLE	3,491	3,583	3,596	3,603

4.2.2 Forecast Energy Consumption

The southern Labrador communities are capacity constrained, whether in isolated or interconnected configuration. A diesel generator portfolio with sufficient capacity to serve peak demand would by definition also be able to provide sufficient annual energy to serve loads, assuming commensurate fuel consumption. This fuel consumption can be offset by integrating renewable resources that are able to provide energy but that lack Firm capacity.

Forecast gross annual energy (which includes allowance for station service load and system losses) is summarized for the select years in Table 10.

Table 10: Forecast Gross Energy Use (MWh)

	2023	2030	2035	2045
CHT / Pinsent's Arm	5,034	5,140	5,187	5,223
MSH / Lodge Bay	5,052	5,098	5,111	5,128
PHS	3,323	3,329	3,329	3,329
SLE	1,555	1,546	1,530	1,503
Combined	**14,964**	**15,113**	**15,156**	**15,183**

The combined annual energy consumption is forecast to increase nominally from the 2012 to 2022 historical average of 14,600 MWh to approximately 15,200 MWh by 2045. This IRP uses 15,000 MWh as a consistent energy consumption throughout the planning period.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

4.3 Current System Configuration

The community electrical generation systems in Southern Labrador are operated as isolated diesel generation islands. CHT is presently being served by temporary mobile gensets due to a 2019 fire at its permanent Diesel Generating Station. There is a pressing need for a long-term supply solution to eliminate the reliability, safety, and environmental risks associated with continuing to use mobile generation as CHT's primary power source. Mobile generation also continues to comprise an unsustainably important component of the supply mix in MSH. The lack of an interconnection between the communities exacerbates both the probability and consequence of community power outages due to mobile genset failures.

NLH also purchases renewable energy in MSH through PPA with St. Mary's River Energy LP, which operates an existing mini -hydro project, and is developing a hybrid solar PV/battery storage system. This IPP contributed 207 MWh of energy to the MSH system in 2022.

Table 11 lists NLH's existing diesel gensets and installed capacities, by community. Currently, each community generating station operates to an N-1 reliability standard, meaning that the peak demand must be met by the combined capacity of the gensets with the largest unit out of service, to ensure that community peak demand can still be served with any unit offline for either planned maintenance or forced outages (unplanned shutdown)[25].

[25] Note: CHT is operating mobile gensets, so, for the purposes of this IRP, it not currently operating at N-1

MIDGARD CONSULTING

Midgard Consulting Inc | 828 – 1130 West Pender St.
+1 (604) 298 4997 | Vancouver BC, Canada
midgard-consulting.com | V6E 4A4

Table 11: Diesel Gensets in Southern Labrador Communities (February 2023)

System	Type	Installed Capacity (kW)	Age	Station Replacement
CHT	Mobile	910	2011	ASAP
	Mobile	910	2019	
	Mobile	725[A]	2012	
	Mobile	600	1997	
	Mobile	1,825[A]	(2023)	
MSH	Stationary	545	2020	2030
	Stationary	545	2016	
	Stationary	725	2020	
	Mobile	725	2013	
	Renewable PPA	240 (Hydro) 190 (Solar)	<5 years	N/A Not an NLH asset
PHS	Stationary	545	2018	2035
	Stationary	725	2018	
	Stationary	455	2005	
SLE	Stationary	200	1986	2045
	Stationary	365	1994	
	Stationary	455	2006	

A. 725 kW genset scheduled to be replaced with 1,825 kW genset in summer 2023.

The combined regional installed capacity is 8.86 MW and will increase to 9.96MW with the addition of the 1,825 kW mobile in CHT, which will replace the current 725 kW mobile genset.

Factoring in N-1 reliability, the communities have the following total and Firm (N-1) capacity. Note that both MSH and CHT have mobile gensets, which should not be used to calculate firm capacity as these are not intended for long term use. Note that renewable generation is not included in capacity calculations, since it cannot be used “on demand”.

Table 12: System Current Installed and Firm Capacity

Community	Total Capacity (kW)	Firm (N-1) Capacity (kW)
CHT / Pinsent’s Arm	3,145	-
MSH / Lodge Bay	2,970	1,090
PHS	1,725	1,000
SLE	1,020	565

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

4.4 Potential 25 kV System Interconnection

Currently each Southern Labrador system (4 systems serving 6 communities) has its own diesel generating station with self-sufficient N-1 capacity. The only major benefit of maintaining the islanded configuration is that there is no need to build any additional power lines to interconnect the communities.

Although islanded operation has historically met the reliability needs of the region, interest in the interconnection alternative has increased since the 2019 fire that destroyed the CHT permanent generating station. This event caused a long-duration community power outage that could have been avoided if it had been possible to redirect power from one of the other community generating stations via an interconnection.

An interconnected configuration would provide several resource-planning benefits, including:

1. Avoid replacement of existing diesel plants (scheduled in MSH 2030, PHS 2035, and SLE 2045).
2. Ability to serve the existing loads with fewer units, due to reduced reserve requirements and the combined complementary seasonal peak load profiles of the communities.
3. Ability to use a wider range of more efficient gensets to serve the combined community loads.
4. Increased access to economically feasible renewable sites and resulting greater renewable energy penetration; and
5. Ability to allow more renewables on the combined system since diesel units encounter operational issues when operated below 30% of rated load.

This section provides a qualitative assessment of the benefits of the proposed system interconnection. Section 7 includes an economic analysis of this system configuration, which is consistent with NLH's mandate to assess resources for least cost and adequate reliability.

4.4.1 Reduced Installed Capacity Requirements

Each isolated community generating station currently houses an extra genset beyond its expected peak load demand, so that if one of the gensets is unavailable during the peak load period due to a forced outage there is remaining capacity available on the system to replace the offline unit. From a simplistic point of view, this means that in the current islanded configuration at least four "spare" (or fully redundant) gensets are required (one for each isolated community). If all six communities are interconnected into a single system, there would only need to be one fully redundant unit available on the system.

In 2020, NLH conducted a reliability assessment related to the proposed southern Labrador interconnected system.[26] That study concluded that reliability could be improved with a transition to a double unit

[26] Reference: Reference: Southern Labrador Interconnection Reliability Assessment (Doc RP-TN-012), dated August 21, 2020

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

contingency (“N-2”) planning metric (i.e., a plan to use two spare gensets in a regional plant instead of one). This configuration would still result in a “savings” of two gensets over the current configuration.

Results from the NLH assessment are summarized in Table 13. These results ignore unavailability associated with local distribution related outages as such outages are common to either individual islanded systems or a combined interconnected system.

Table 13: NLH Reliability Assessment Results

Scenario	Loss of Supply	25 kV System Outage	Total	EUE (MWh)
2015-2019 Southern Labrador Individual Systems (Average)	0.177%	-	0.177%	26
Forecast S. Lab. Regional Plant (N-1)	0.139%	0.0816%	0.2206%	33
Forecast S. Lab. Regional Plant (N-2)	0.037%	0.0816%	0.1186%	18

Note: EUE is the Expected Unserved Energy which is calculated by multiplying the total unavailability (excluding local distribution unavailability which is assumed common to all scenarios) by the 2023 forecasted Gross Energy Consumption of ~15,000 MWh.

It is concluded that an N-2 planning metric would result in a nominal increase in reliability relative to the present configuration (Annual EUE of 18 MWh vs. 26 MWh) as compared to an N-1 planning metric, which would result in a nominal decrease of reliability relative to the present configuration (Annual EUE of 33 MWh vs. 26 MWh). While the N-1 Loss of Supply forecast for the Regional Plant is improved from the 2015-2019 average, forecast outages for the 25kV system result in an increase in the EUE of 7MWh relative to the present configuration (33 MWh less 26 MWh).

In addition to the reduced genset count (to satisfy either the N-1 or N-2 planning metric) described above, the different communities experience peak loads during different seasons. MSH and CHT experience their highest loads during summer when the seafood processing plants are operating, while SLE and PHS have winter-peaking loads, which is typical of cold climate residential communities. This seasonal peak load complementarity means that the aggregated coincident peak load used for calculating the required system peak resource capacity is nominally lower than the sum of the non-coincident peak loads of the individual communities which further reduces required generation capacity.

4.4.2 Other Reserve Requirements

Part of the planning process for power utilities is to ensure adequate system reserve capacity at all times. Generating resources must not only be adequate to serve the expected peak system loads, but they must also be sized larger than the expected loads to account for reserve requirements.

Reserves serve various functions in a power system.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1. Spinning reserves allow the system to adapt in real time to changing loads, which vary throughout the day. Spinning reserves are typically provided by maintaining headroom between real time load demand and the total capacity of all dispatchable online generators. When load increases to the extent that insufficient dispatchable generator capacity remains, supplemental reserves must be brought online.
2. Non-spinning reserves (or supplemental reserves) are offline dispatchable generators that can be brought online with a short delay to compensate for forced outages to spinning units, or when daily or seasonal demand fluctuations exceed the capacity (including reserves) of the online generators.
3. Planning reserves represent the total on-peak Firm generation capacity above the peak system demand expected over the planning period, allowing for seasonal unit de-rates. Planning reserves typically allow for at least one spare unit above the system peak demand (N-1), plus a nominal planning reserve margin based on a percentage of the total peak demand. Most utilities plan resources on large interconnected systems to allow for a resource-driven loss of load expectation (“LOLE”) of no more than one day in ten years, or 0.1 days (2.4 hours) per year.

The reserve requirement means that a system must always carry more Firm generating capacity than its expected loads, which requires planners to develop high-confidence forecasts of system peak load conditions over the planning period, since additional resources cannot be added quickly if actual loads exceed forecast loads in real time operations – the operational alternative is to shed loads to restore reserve margin.

The amount of spinning reserves that must be maintained (which on a diesel system requires incremental fuel use) is determined by the utility based on actual experience with the load being served. Non-spinning reserve is represented by idle capacity – or a capital cost with no fuel expense.

The larger and more diversified the served load on a system is, the less instantaneous % variability in load is expected, which would decrease the requirement for % spinning reserve – as would be determined by NLH over time based on the observed response of the load being evaluated.

4.4.3 More Efficient Gensets

In general, larger thermal gensets are more fuel efficient than smaller thermal gensets. This is why baseload thermal generation plants in large non-hydro North American power system typically feature large (e.g., 400+ MW) individual generating units. Four small, isolated systems require (at least) four small gensets to be run most of the time. With a networked system the overall load could be served by one (or two) larger genset(s) for much of the year, which would save fuel, reduce greenhouse gas emissions, and require less overall maintenance than would four smaller gensets.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

In addition to genset size efficiency, fuel storage and handling efficiency can be optimized for a larger central plant. Refuelling logistics are also simplified, since fuel trucks only need to access the central plant. This configuration should also reduce environmental risks due to fuel spills, since fuel trucks will less frequently need to access the three communities that don't host the central generating plant.

4.4.4 Increased Access and Penetration for Renewables

Renewable energy sites are not useful in isolation: they need to generate power (whether by sun, wind, or water) and then deliver this energy to where it will be used, typically via a grid interconnection, which represents a significant cost for any renewable project. For smaller renewable projects, of a scale to supply smaller islanded loads, any distance more than a few hundred meters from those 4.16 kV distribution systems means that the cost of interconnection could be greater than the cost of building the renewable generation. If a transmission system is built between the communities, not only would larger renewable projects be potentially feasible, but the potential location would be greatly expanded to anywhere within a few hundred meters of the 25 kV interconnection lines (in practice, along the roads connecting the communities), thereby dramatically increasing the number of potential sites and the footprint available for development.

A major factor impacting renewable penetration is that if one area is particularly good for renewables (like a field where the sun often shines, or a particularly windy outcrop) the amount of power that can be used is directly related to how much power is needed by loads. If the system is islanded, then only the local loads can use that power, while on a networked system this energy can be sent wherever it can be used.

An important technical factor that makes interconnected systems better hosts for integrating renewables is the superior response of interconnected systems to output variability (e.g., solar: sunrise / intermittent clouds / sunset; wind turbines: calm / breeze / gust / gale / calm). Interconnected systems have larger baseloads, larger generating units with a larger range of dispatchable output, and greater rotating inertia, all of which help to mitigate the variability and the resulting impact on interconnected system power quality (voltage surges and sags, frequency variability).

4.4.5 System Configuration Alternatives Summary

There are benefits and risks associated with either islanded or interconnected operations, and either configuration can be planned and designed to meet the "reliable" requirement of NLH's mandate. Further investigation is warranted to determine which of these systems best satisfies the "lowest cost" mandate, or if they are effectively identical, with reduced fuel costs and genset redundancy being offset by additional transmission costs. Table 14 summarizes the two interconnection alternatives.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 14: System Configuration Alternatives Summary

	Islanded operation	Interconnected operation
Cost	No incremental transmission costs Higher fuel costs More generating units Higher maintenance costs	Incremental transmission costs Lower fuel costs Potential savings on gensets Lower maintenance costs
Renewable Energy Development	Limited economic sites Limited maximum facility size Limited renewable penetration	Larger development footprint, more available sites Larger maximum facility size Increased renewable penetration

4.5 Gap Analysis

There is presently sufficient capacity in each of the South Labrador isolated communities to meet current loads, although the mobile gensets presently in place in CHT and MSH are short-term solutions and should not be counted upon as long-term planning resources, as demonstrated by the failures of two mobile gensets operating in CHT during the last year. Excluding the mobile gensets from the permanent Firm resource planning portfolio, the southern Labrador communities presently have a significant Firm resource capacity deficit.

There are two analyses that are relevant in forecasting the region's generating capacity deficit. There are:

1. Continued operation of the region in separate islanded load centres; or
2. Construction of a 25 kV interconnection and marrying the disparate loads into a single system.

4.5.1 Isolated Configuration Firm Capacity Deficit

The total immediate Firm resource capacity deficit for islanded operation of the four South Labrador systems serving six communities is approximately 3,870 kW, of which 3,145 kW is the result of the portable gensets in use at CHT, with an additional 725 kW due to the single portable genset in MSH.

The forecast peak demand for each community is shown in Table 15.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 15: Forecast Capacity Gap - Islanded Communities - Select Years (kW)

Community	Year	Forecast Peak Demand (kW)	Installed Capacity (kW)	Firm (N-1) Capacity (kW)	Forecast Capacity Gap (kW)
CHT / Pinsent's Arm	2023	1,556	4,245	0*	1,556
	2030	1,649	3,145	0*	1,649
	2035	1,664	0	0*	1,664
	2045	1,676	0	0*	1,676
MSH / Lodge Bay	2023	1,177	2,970	1,090*	87
	2030	1,188	0	0	1,188
	2035	1,191	0	0	1,191
	2045	1,195	0	0	1,195
PHS	2023	753	1,725	1,000	0
	2030	754	1,725	1,000	0
	2035	754	0	0	754
	2045	754	0	0	754
SLE	2023	384	1,020	565	0
	2030	382	1,020	565	0
	2035	378	1,020	565	0
	2045	371	0	0	371

*Note that mobile gensets and renewable generation have been assumed to have no Firm capacity

Based on this analysis, CHT immediately needs roughly 1,600 kW of additional capacity, which will require on the order of 2,500 kW of incremental Firm generation to allow for N-1 redundancy and operating reserves.

MSH also needs additional capacity, likely either a 545 kW genset to just meet the capacity requirement, or a larger more fuel-efficient unit. The MSH generating station is slated for replacement in 2030, and the existing site does not allow for expansion, so in the islanded configuration the MSH upgrade will require development of a new generating station at a new location, and this may need to be expedited based on the deteriorating condition of the existing building.

There is sufficient capacity in both PHS and SLE until the planned retirement of the respective generating stations in 2035 and 2045. Individual units in both of those stations are aging and selective unit replacement may be required prior to end-of-life for those stations.

4.5.2 Interconnected Configuration Firm Capacity Deficit

Section 4.4 introduced potential benefits of interconnecting the four systems with a 25 kV interconnection system. Table 16 below shows forecast annual peak demand gaps for selected community interconnection options. The appropriate planning reliability metric (i.e., N-1 versus N-2) is an unresolved matter (which will be addressed later in this IRP), so the resulting gap is shown for both metrics.

Table 16: Forecast Annual Peak Demand Gap – Select Interconnected Communities (kW)

Interconnected Systems	Year	Forecast Peak Demand (kW)	Installed Capacity[A] (kW)	N-1 Planning Metric[B]		N-2 Planning Metric[B]	
				Existing Capacity (kW)	Forecast Capacity Gap (kW)	Existing Capacity (kW)	Forecast Capacity Gap (kW)
All	2023	3,418	8,430	3,835	-	3,110	308
	2030	3,511	2,745	2,020	1,491	1,475	2,036
	2035	3,524	1,020	565	2,959	200	3,324
	2045	3,533	-	-	3,533	-	3,533
CHT+PHS+MSH	2023	3,107	7,410	2,815	292	2,090	1,017
	2030	3,201	1,725	1,000	2,201	455	2,746
	2035	3,218	-	-	3,218	-	3,218
	2045	3,232	-	-	3,232	-	3,232
CHT+PHS	2023	2,045	4,870	1,000	1,045	455	1,590
	2030	2,138	1,725	1,000	1,138	455	1,683
	2035	2,153	-	-	2,153	-	2,153
	2045	2,164	-	-	2,164	-	2,164

A – Installed capacity includes mobile units through 2029. Capacity of MSH PPA generation not included.
B. – N-1 and N-2 do not include mobile units.

This analysis highlights the potential to defer genset purchases for various interconnection configurations. Various configurations and generation scenarios are economically modelled in Section 7.

4.6 Addressing Forecast Planning Gaps

There are fundamentally two mechanisms for closing a resource gap: increasing supply (by adding more generation resources) or reducing demand.

4.6.1 Increasing Supply

The remainder of this IRP explores supply alternatives that can be used to address forecast gaps while adhering to NLH's mandate of reliable, least cost service to this capacity constrained region.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

4.6.2 Load Reduction

Peak demand and total energy consumption on electric systems can be purposefully reduced through the deployment of Demand Side Management (DSM) programs. DSM is a term that can be applied to a wide range of energy and demand reduction initiatives, including the adoption of increasingly rigorous building codes and appliance efficiency standards, energy efficient technology advancements (LED lights), and voluntary load curtailment programs, such as interruptible rates, time of use rates, or centrally controlled selective load management (e.g., temporarily switching off hot water tanks during system peak loads).

DSM programs can be treated as "generation resources" since offsetting peak loads and/or annual energy consumption can reduce the demand-supply "gap" and eliminate the need for additional generation resources. In this way, cost-effective DSM programs that encourage reduction of peak demand and energy use while maintaining customer satisfaction can be treated as equivalent to new generation resources.

NLH has offered direct installs of LED lighting through its isolated systems energy efficiency program since 2010. NLH has reported that the market potential for this type of transition is becoming limited. Further, NLH has indicated that it is planning to study and pilot deeper energy efficiency retrofits in its diesel systems (i.e., building envelope) as a means to achieve future energy efficiency goals going forward.

Notwithstanding these active opportunities, Appendix A looks further into the applicability of DSM programs in resource planning for the Southern Labrador region. To summarize, very limited potential was found for the application of active DSM measures such as interruptible rates, particularly since the major industrial customers in the area cannot shed load during the summer peak load season, because processing loads coincide with seasonal fishery activities, and the associated processing activities are time sensitive and not conducive to interruption. Residential customers can be expected to adopt technology advancements such as LED lighting and high-efficiency appliances without significant DSM program encouragement, since these are becoming the only technology options available in the modern marketplace.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5 TECHNICAL EVALUATION OF ENERGY SUPPLY TECHNOLOGIES

The first step in planning a resource portfolio is to identify the suite of available resource technologies and evaluate the technical merits of each for the specific application. Many technology alternatives could be considered, but not all are conducive to application in remote communities. In the context of Sections 5 through 8, each prospective resource portfolio alternative will be referred to as a scenario – adopting this nomenclature will simplify comparison of the different scenarios being evaluated.

Because of their complete dependence upon the reliable self-sufficiency of local power supply resources in all conditions and circumstances (since they cannot lean upon neighbours for supply), scenarios for isolated remote communities must exclude any material dependence on immature technologies that have not been extensively tried and tested. Larger interconnected systems have the flexibility to implement prototype installations of leading-edge emerging technologies without significant risk, because they can access diverse additional resources to compensate for operational failures of individual prototype facilities.

In contrast, failure of a prototype installation in a remote isolated community can leave the community exposed to supply deficiencies or even extended power outages until replacement resources are implemented.[27] This means that dependence upon emerging technologies in isolated remote communities must be deferred until the technologies are mature and proven reliable. Although placeholders for emerging technology resources may reasonably be included in future years of remote community resource plans, dependable mature resource alternatives must also be identified for these future periods in case the emerging technology does not prove out or is found uneconomical to implement and operate.

Although nuclear power could be considered as an extensively tested technology, the Newfoundland and Labrador Electrical Control Act (1994) mandates that "planning for future power supply of (Newfoundland and Labrador) shall not include nuclear power". In any case, resource technology candidates must be practical to operate and maintain using local skills and trades, as dependence upon any technology that requires ongoing intervention by people with very specialized skillsets would be inappropriate, since the specialized skills are hours (or days) from deployment to the communities in an emergency.

Based on the above considerations, this section will evaluate the appropriateness of including each of the following supply resource technology alternatives in the South Labrador scenarios.

[27] Note: The same sorts of problems can occur with existing technologies such as reciprocating diesel generators, as demonstrated by the recent Charlottetown fires. However, the risk of mis-operation is proportionately much higher with prototype technology installations. In addition, the use of mobile diesels as baseload resources in the cold climate of Southern Labrador is an extenuating factor in the cited instances.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

These are:

1. Biomass;
2. Diesel;
3. Geothermal;
4. Hydroelectricity;
5. Natural Gas;
6. Biomass;
7. Diesel;
8. Geothermal;
9. Hydroelectricity;
10. Natural Gas;
11. Solar;
12. Tidal;
13. Wave; and
14. Wind.

Batteries are not considered in this list of generation technologies because in fact, they represent a load owning to a less that 100% round-trip efficiency. This IRP considers battery storage costs and benefits in subsequent sections.

It is important to reiterate that just because an emerging technology is deemed insufficiently mature at this time does not mean that it will never be a solution in these communities. Forty years ago, wind and solar power resources would have been considered emerging technologies and would not have been appropriate to consider as resource candidates for the isolated Southern Labrador community systems. These are now two of the fastest growing technologies in the global electric energy market, with extensive application worldwide. Similarly, we expect that some of the technologies assessed as being unacceptably immature today may become viable in the next decade and should be evaluated the next time additional generation is needed in the region.

5.1 Technology Evaluation Criteria

The listed resource technologies will be evaluated against three screening criteria:

1. Is this technology technically feasible?
2. Can this technology supply dependable capacity?
3. Is the fuel used by this technology available in the Southern Labrador region?

5.1.1 Technical Feasibility

Technical feasibility will be established based on the maturity of the technology, along with the availability of the technology for procurement / purchase. Mature technologies will generally have a selection of reliable suppliers and come in a range of available sizes and configurations, while less mature technologies may have few or only one supplier, with very specific application constraints. Emerging technologies may still be prototyping equipment, with no commercially available equipment available on the market.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5.1.2 Dependable Capacity Evaluation

The parameter of greatest interest when evaluating the reliability of resource options for capacity-constrained power systems such as the South Labrador communities is the resource's dependable capacity. Dependable capacity refers to the power the resource technology being evaluated can be reliably counted upon to deliver during the time of peak system demand – the need for dependable capacity never goes away, but there must be at least enough aggregate dependable capacity in the system to supply peak loads, allowing for operating reserves and contingencies.

Electrical utilities have an obligation to serve connected customer loads at all times, and utility resource plans must therefore account for both planned resource outages (i.e., scheduled maintenance) and unplanned or forced resource outages, (i.e., unexpected failures).

Furthermore, resource plans must accommodate anticipated seasonal unit capacity de-rates, for example, due to changes in intake air density for gas turbines, cooling pond temperatures for large thermal plants, or fuel availability for any type of thermal plant (including biomass).

Increasingly, resource plans must also account for the fuel supply volatility of non-thermal renewable facilities such as hydro, wind or solar PV.

1. Hydro energy availability can vary significantly over daily or even hourly periods for small run of river plants. Large storage hydro facilities can buffer variable stream flows across months, seasons or even years for the largest storage reservoirs, but such facilities are extremely difficult to site and permit.
2. Wind energy can vary substantially over a period of minutes for gusts or storm fronts, to hours for slow moving weather systems. The most rapid wind turbine fuel variability occurs when wind speeds increase (even gradually) above the turbine's maximum wind speed threshold, at which point the turbine will shut down for self-protection – ironically, in such conditions there is too much fuel.
3. Solar energy is only available between sunrise and sunset and varies daily and seasonally depending upon the incident angle of the sun relative to the panel face. The amount of solar energy available during the daytime can be attenuated by clouds, fog, haze, or surface contamination (snow, ice, or dust). Although most of these attenuating factors tend to change gradually across days or weeks, during the summer peak solar production season, the formation and passage of tall cumulus clouds can cause intense and rapid solar radiation variability between sunny breaks and cloudy spells.

As discussed earlier in this IRP, the Southern Labrador community systems are presently capacity constrained, whether taken as isolated systems or combined into an interconnected network. For systems that rely on diesel generation, energy is only limited by fuel storage and delivery constraints – if the generating scenario has sufficient capacity to dependably serve peak loads, energy is not typically a concern. Therefore, any new resource developed to either replace existing diesel generation or to provide new

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

capacity to serve growing loads must have Firm on-peak capacity equivalent to the diesel generation that is being replaced or augmented.

BC Hydro's IRP application presently being heard by the BC Utilities Commission provides an instructive assessment of the expected on-peak capacity that will be provided by different types of renewable resource technologies, including both non-intermittent and intermittent resources. Of particular note:

> *"[F]or intermittent resources such as wind, non-storage run-of-river hydro, and solar, we determine capacity contribution by calculating an effective load carrying capability which reflects their increased variability and the aggregation benefits that come with multiple resources. We determine effective load carrying capability factors that express the peak capacity contributions of independent power producer resources as a percentage of their nameplate installed capacity."*[28]

Table 17: BC Hydro's Determination of Capacity Contribution of IPP Renewable Resources[29]

Non-Intermittent Resource	Dependable Capacity Factor (% of Installed Capacity)
Stand-alone biomass	96
Biomass with a customer load	62
Energy recovery generation	55
Municipal solid waste	89
Biogas	72
Natural gas-fired generation	90
Storage hydro	76
Intermittent Resource	**Effective Load Carrying Capability (% of Installed Capacity)**
Run-of-river hydro	15
Wind	24
Solar	0

The above excerpt indicates that the intermittent resource Effective Load Carrying Capabilities ("ELCC") determined by BC Hydro take into account aggregation benefits that accrue to a large portfolio of multiple resources that use the same technologies, such as a large dispersed solar or wind portfolio where it is unlikely that all of the generation assets (wind turbines or solar cells) were idle at the same time. Such benefits would not apply to individual new resources added to any of the South Labrador isolated systems (although an aggregation benefit could begin to accumulate in the interconnected configuration alternative as multiple intermittent resources of the same type are added to the networked system). Since the total renewable

---

[28] Reference: BC Hydro 2021 Integrated Resource Plan, Exhibit B-1, p. 5-22, lines 7 - 13

[29] Reference: BC Hydro 2021 Integrated Resource Plan, Exhibit B-1, p. 5-23, Table 5-5

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

energy that could be supplied to southern Labrador, even on an interconnected system, is relatively small, it is anticipated that there will be a small number of systems. These systems are likely to be influenced by similar operating conditions (cloudy weather or calm conditions across all of southern Labrador)

It should also be noted that aggregate run-of-river ELCCs shown in the BC Hydro example also account for the robust winter peak production contribution at facilities (such as Kokish Hydro, McNair Creek Hydro, Gold Creek Hydro, etc.) sited in rainy lower elevation coastal BC, the mildest winter climate zone in Canada. This favourable costal hydro ELCC is tempered by facilities with minimal expected production during winter peak, such as facilities sited at high-elevation or in the BC interior with its colder continental winter climate.

Individual run-of-river hydro projects in Labrador can be expected to have significantly lower ELCC values than the aggregate values shown in the BC Hydro IRP.

Although it is possible to firm production of intermittent non-renewables by adding battery storage systems, the costs of adding sufficient battery storage to enable intermittent renewables to provide reliable capacity during peak winter loading periods significantly increases per unit resource capital costs and must be factored into their levelized costs of energy and capacity. Although storage devices can be counted as capacity resources, they are effectively an energy load rather than an energy resource due to the round-trip losses incurred during each charge/discharge cycle. Typical round-trip battery system efficiencies range from 70% to 90% depending upon the battery technology and conversion (inverter/rectifier) equipment used in each specific application.[30] This means that 110 to 140 kWh must be put in to get 100 kWh of energy back out.

The above renewable resource capacity characteristics can be contrasted with on-peak dependable capacities representing a very high proportion of nameplate rating (e.g., 99%) for dispatchable resources such as the reciprocating diesel gensets that have historically been used in the Southern Labrador isolated community systems. Diesel fuel has a very dense energy content, is easily stored adjacent to generating facilities in tanks equipped with spill-containment reservoirs and is readily converted to electrical power in quantities as needed to serve fluctuating real time demand.

Ultimately, a resource portfolio that comprises sufficient dependable capacity from dispatchable resources (such as diesel gensets) to serve peak load demand can be combined with intermittent renewable resources shown to be technically and economically viable. This will result in a scenario containing the best qualities of both technologies: reliable least cost service configured to support an increasing proportion of annual energy being produced by non-emitting resources, with a corresponding reduction in the cost of diesel fuel and the aggregate running hours of the diesel fleet. The interconnected configuration described above will facilitate increasing levels of renewable penetration by expanding the economically viable renewable resource

[30] Reference: https://www.eia.gov/todayinenergy/detail.php?id=46756

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

development footprint and by creating a larger more robust system with a greater capacity to integrate intermittent renewables.

Dispatchable resources such as storage hydro and thermal systems fueled by biomass or fossil fuel are considered to have dependable capacity, since they can be dispatched to provide needed power at any time, as long as fuel is available, and they are good operating condition. The on-peak dependable capacity of such resources is typically expressed as a percentage of their nameplate capacity, with the ratio determined by typical annual availability factors for the specific technology type, and accounting for expected seasonal de-rates.

5.1.3 Resource Availability

Generating resources can only produce power when they have fuel.

Thermal plants use transportable or extractable fuels such as diesel, natural gas, coal or biomass, and their respective fuel supplies are usually stored near the plant in tanks or stockpiles to ensure dispatchability and production continuity. Storage hydro plants stockpile their water resources in upstream reservoirs behind large dams. In this IRP the fuel supply for technologies that can utilize fuel storage will be evaluated based on whether there is an existing source of supply or the requirements to establish a supply chain into the region.

Energy cannot be stockpiled for intermittent renewable resources such as wind, solar and non-storage run-of-river hydro facilities – they can only generate power when the resources (wind, sunshine, and streamflow) are provided by nature.

Evaluating the resource availability for renewable technologies is an intensive site-specific activity that typically involves years of environmental and engineering studies. These studies determine if the potential development site has (among other things) the appropriate climatic conditions and terrain features to provide an adequate resource supply for the respective technology. Examples include exposed sunny areas for solar; breezy plateaus, ridges or passes for onshore wind; streams with large dependable precipitation catchment areas for run-of-river hydro; or a high-quality geologic heat source in proximity to water for steam generation for geothermal.

Such studies are beyond the scope of this IRP, so evaluating resource availability for renewables in this study is limited to estimating the likelihood of finding sites in the region that would be feasible for economic renewable development.

5.2 Technical Resource Evaluation

As an initial screen, each of the studied technologies was evaluated for technical viability, dependable capacity, and fuel availability in the South Labrador region. A summary table of the screening results is

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

presented Table 18. The technologies evaluated as "viable" for either energy, but not capacity will be investigated further in Section 6.

Table 18: Initial Screen – Resource Technical Viability, Dependable Capacity and Fuel Availability

Technology	Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result	
				Capacity	Energy
Biomass	High	Yes	No	Fail – Fuel Unavailable	
Diesel	High	Yes	Yes	Viable	Viable
Geothermal	Moderate	Yes	No	Fail – Resource Unavailable	
Hydroelectricity - Storage	High	Yes	Yes	Viable	Viable
Hydroelectricity – Run-of-river	High	Site specific	Site specific	Site specific	Viable
Natural Gas	High	Yes	Supply system needed	Viable	Viable
Solar	High	No	Yes	Fail	Viable
Tidal	Unproven	No	Yes	Fail – Technology Unavailable	
Wave	Unproven	Unknown	Yes	Fail – Technology Unavailable	
Wind	High	No	Yes	Fail	Viable

Further discussion of these technologies is presented below.

5.2.1.1 Biomass

Biomass generation typically involves burning organic materials to heat a working fluid (often water) into a gaseous state (steam) which is used to drive a turbine and generate electrical energy. Biomass systems are generally derivatives of the standard Rankine cycle steam turbine systems used for coal-fired plants, with appropriately modified fuel handling systems, and there are multiple potential technology suppliers. Biomass systems generally use waste materials such as sawdust or wood chips for fuel but can also use materials such as rendered fat or fish oils. The feasibility of biomass electricity generation is dependent on a reliable fuel supply available near the biomass plant. Biomass plants are typically built in conjunction with forestry operations or in areas that have significant amounts of municipal solid waste with minimal incremental fuel transport costs. There are currently no large complementary industrial or municipal operations in Southern Labrador able to reliably provide an adequate amount of feedstock to support a Biomass facility. As a result, Biomass will not be further considered as a potential generation technology in the region due to lack of fuel.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	Yes	No	Fail – Fuel Unavailable

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5.2.1.2 Diesel

Diesel gensets sized appropriately for the Southern Labrador community requirements typically use a reciprocating engine[31] as the prime mover, like the large diesel engines used in railway locomotives. These engines drive a generator to produce electrical energy. This combination of an engine and a generator is called a genset. Diesel gensets are a mature technology with multiple manufacturers, including Caterpillar ("CAT"), Cummins, and others. Diesel gensets are available in a wide range of sizes and configurations, including units ruggedized for arctic conditions. Diesel generation is a highly reliable form of generation, and the fuel is stable and easy to transport. As a result of the combination of reliability and ease of fuel transportation, diesel generation is the most commonly used technology for remote community generation in Canada. Currently, all of the southern Labrador communities are primarily powered by diesel fueled generation.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	Yes	Yes	Pass (for energy and capacity)

<u>Biodiesel Fuel Substitution:</u>

The use of biodiesel as a climate-friendly alternative to fossil fuels has been considered. Biodiesel is a plant-based fuel derivative that can be mixed with regular diesel or fully substituted and used in standard or modified diesel engines. Nomenclature is typically expressed as the percentage of the mix, such that B2 fuel would represent a mix of 2 percent biodiesel and 98 -percent standard fuel up to B100, which would be all bio-fuel.

While representing a potentially attractive alternative for climate conscious users, there are a number of challenges that preclude, or limit biodiesel's use in NLH's situation. These include:

1. Limited number of large-scale suppliers in North America with a predicted supply crunch in North America
2. Limited Shelf Life
3. Gels in cold temperatures
4. Voided Engine warranties due to pH of fuel above B20
5. Optics of using agricultural land to fuel engines

[31] Note: Diesel turbine generators are also available, but these are typically sized larger than is required in the Southern Labrador communities.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

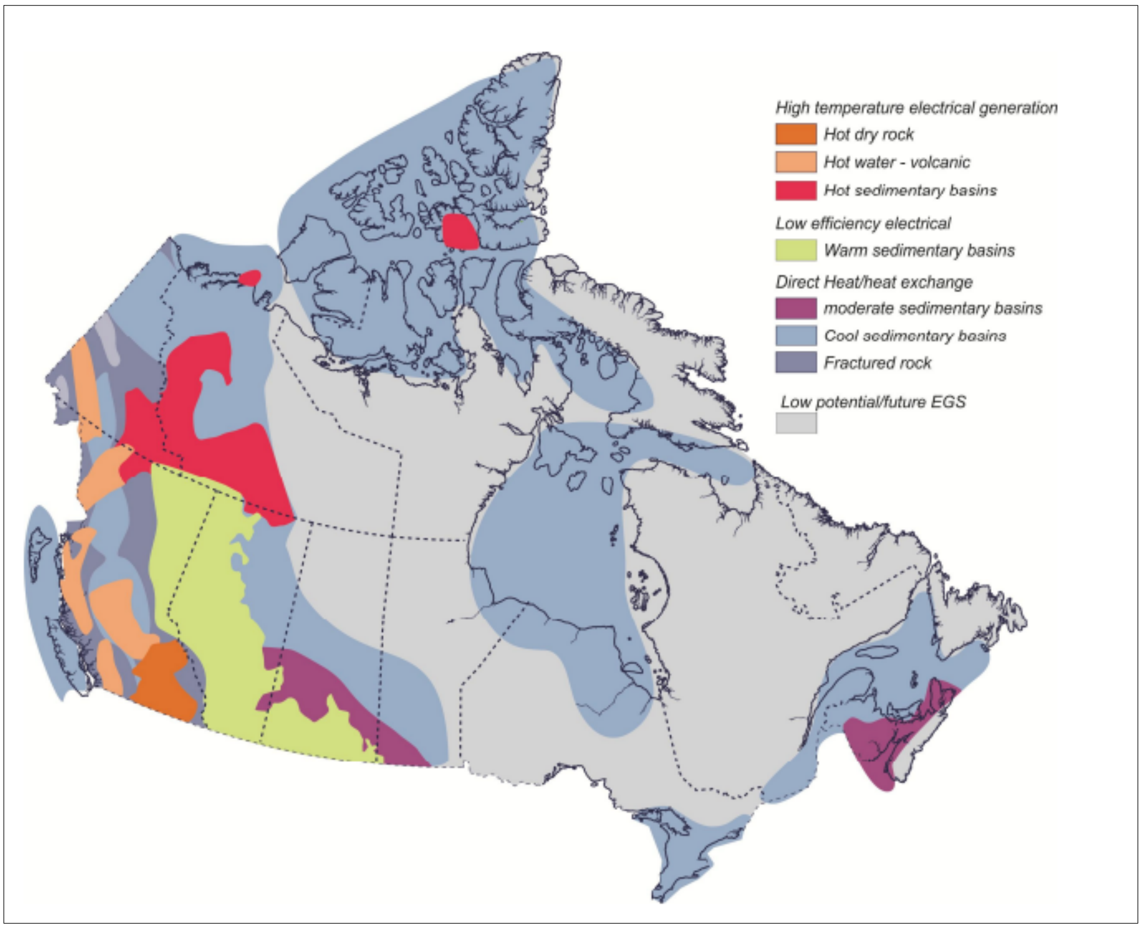
It is concluded that some amount of biodiesel could possibly be included in the fuel mix without significantly changing any of the IRP capital expenditure conclusions, except that the fuel cost will be higher, fuel handling will be more complex and engine life could be impacted.

A similar conclusion has been drawn with other renewable diesel substitutes.

5.2.1.3 Geothermal

Geothermal power plants use naturally occurring steam or hot water present in underground reservoirs to drive a steam turbine to generate electricity. Geothermal generation is a clean and reliable source of electricity but has very limited geographic availability due to localized geologic constraints.

Figure 5: Canadian Regional Geothermal Generation Potential



As shown in Figure 5, Newfoundland and Labrador have low potential for geothermal energy generation.[32]

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
Moderate	Yes	No	Fail – Fuel Unavailable

[32] Reference: Newfoundland & Labrador Energy Innovation Roadmap: Priority Identification (Phase 1)

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5.2.1.4 Hydroelectricity

Hydroelectric power plants use flowing water to turn a turbine and drive an electric generator. Conventional storage hydroelectric systems use a large dam to form a reservoir, which is the most cost-effective method of utility-scale energy storage currently available. Smaller "run of river" hydroelectricity systems have a much smaller environmental footprint but are also much more variable in their power output due to the volatile nature of undammed stream flows. Hydroelectricity is a very mature technology, being one of the first forms of electrical generation technology that was developed. Numerous companies around the world manufacture turbines and generators, including General Electric, and ABB, as well as specialty firms such as Andritz and Canyon Hydro. The provinces of British Columbia, Manitoba, Quebec, and Newfoundland & Labrador, rely almost exclusively or largely on Hydroelectric power to provide inexpensive and highly reliable power. World-class generation facilities including Churchill Falls and Muskrat Falls have been constructed in Labrador, and a small hydroelectric generating station operated by St. Mary's River Energy LP provides energy to MSH through a PPA with NLH. A hydropower assessment to evaluate small hydro generation opportunities in the Southern Labrador region was conducted in the last decade.[33] This study concluded that there were multiple sites with high potential for hydroelectric development in the southern Labrador. Hydroelectric potential to provide either capacity or energy is highly dependent on specific site characteristics.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	Site specific	Yes	Pass (for capacity and energy)

5.2.1.5 Natural Gas

Natural gas gensets can utilize either reciprocating engines similar to diesel reciprocating engines, or gas turbines which are similar to commercial jet engines. Natural gas has become the preferred fuel for dependable dispatchable electric generation in North American because of its comparatively low capital and operating costs, high reliability and relatively low greenhouse gas emissions compared to alternative fossil fuels such as diesel or coal. There are numerous companies that build commercial gas gensets, including Hitachi, Siemens, and General Electric. Natural gas is not commonly used in remote communities because it is much more difficult to store and transport than diesel fuel. Currently the closest natural gas supply pipeline is located in Saguenay, QC, which is almost 1,800 km (by road) from the southern Labrador region. Natural gas can also be shipped by sea as a liquid ("LNG") or in compressed form ("CNG"), with the closest port terminal in Montreal QC, roughly 1,700 km by sea to Southern Labrador.

[33] Reference: Hydraulic Potential of Coastal Labrador, Hatch, March 2013

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Natural Gas generation systems would require additional safety systems due to the presence or potential presence of flammable gases based on the "Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas (National Fire Protection Association code 497)" which is a safety classification that is applied to areas which can or will be exposed to flammable / explosive gases. The associated electrical equipment and fire code requirements would significantly increase the cost of plant construction, since they will often include safety interlocks, gas detection systems, high throughput ventilation systems and requirements for rated equipment (ranging from sealed to "inherently safe") and may also require explosion proof construction. These considerations are exacerbated for systems using Hydrogen as the primary fuel or as an admixture. Hydrogen gas was not considered as an alternative fuel in this IRP, since hydrogen combustion systems typically involve large gas turbines that would be inappropriate for the Southern Labrador system size, and there would be significant challenges in delivering hydrogen fuel to the region.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	Yes	Supply system needed	Pass (for capacity and energy)

Hydrogen Fuel Substitution:

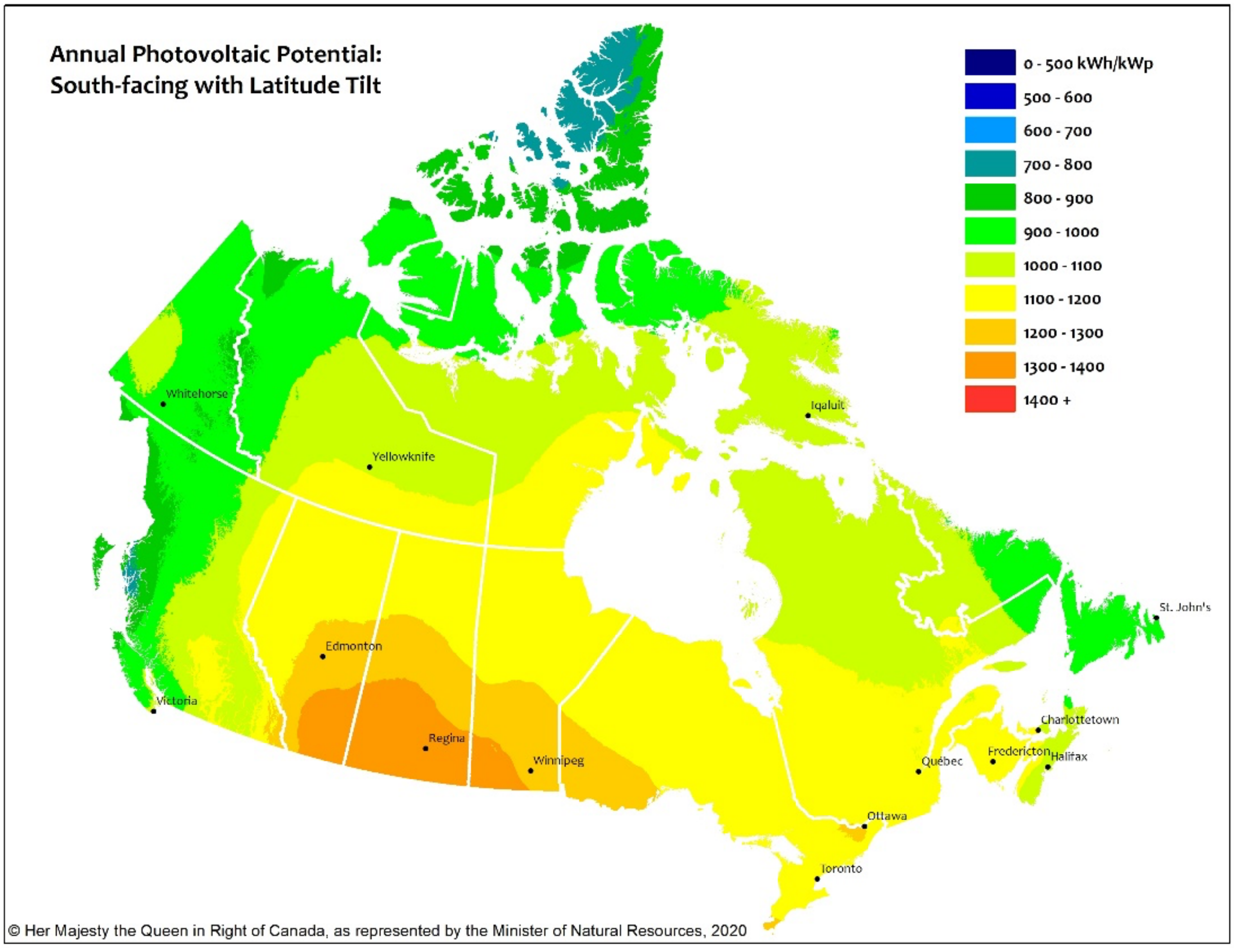
Using Hydrogen as an additive or for full substitution as a feedstock for CNG engines was also considered. However, similar to the above discussion regarding biodiesel, hydrogen faces inherent incremental challenges to its adoption by NLH in a CNG-based system, primarily related to supply, transport and handling difficulties which would increase capital and fuel costs above those of a purely CNG-based system. In addition to the fuel handling challenges associated with Natural Gas, Hydrogen must be stored as a cryogenic fluid, and generally loses some percentage (from 0.01% to 3% depending on the systems used) of stored volume per day due to hydrogen boil off.

5.2.1.6 Solar

Solar electrical generation involves converting sunlight energy into electricity, and photovoltaic ("PV") panels are the most common solar energy conversion technology used presently. PV systems represent an increasingly inexpensive source of electrical energy, but they only provide power when the sun is shining, which is a liability in cold northern climates where highest loads occur during the dark and cloudy days of winter. NLH has conducted a solar assessment for multiple communities in Southern Labrador and concluded that there is a potential to utilize solar energy. St. Mary's River Energy LP has an installed solar generating system that has provided energy to MSH since 2022 through a PPA with NLH. A Natural Resources Canada map of photovoltaic potential across Canada is shown in Figure 6.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Figure 6: Photovoltaic Potential and Solar Resource Maps of Canada[34]



Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	No	Yes	Pass (for energy)

[34] Reference: https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/renewable-energy/solar-photovoltaic-energy/tools-solar-photovoltaic-energy/photovoltaic-potential-and-solar-resource-maps-canada/18366

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5.2.1.7 Tidal

There are two main forms of tidal generation: storage systems which operate by damming incoming tidal surge in an inlet, which operates similar to a conventional storage hydro project (but with two daily cycles); and "stream" systems which operate in a narrow channel and use the flow of water to drive a turbine. In Canada a tidal generator was deployed off the coast of Vancouver Island for three years before it was decommissioned since "…the ability of the generator (to) operates continuously and to provide significant power for the Integrated Energy system at Race Rocks was very limited." An experimental storage hydro plant was installed in the Annapolis basin in Nova Scotia in 1984. NSPI is currently seeking regulatory approval to retire the facility.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
Unproven	No	Yes	Fail – Technology Unavailable

5.2.1.8 Wave

Wave power devices harvest energy from the surface motion of waves or from pressure fluctuations below the water's surface. Canada's Atlantic coast is rich with wave energy resources and has high potential for wave electricity generation. Similar to tidal generation technology, wave energy generators are currently under development and there are currently no commercial suppliers of wave energy generators.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
Unproven	Unknown	Yes	Fail – Technology Unavailable

5.2.1.9 Wind

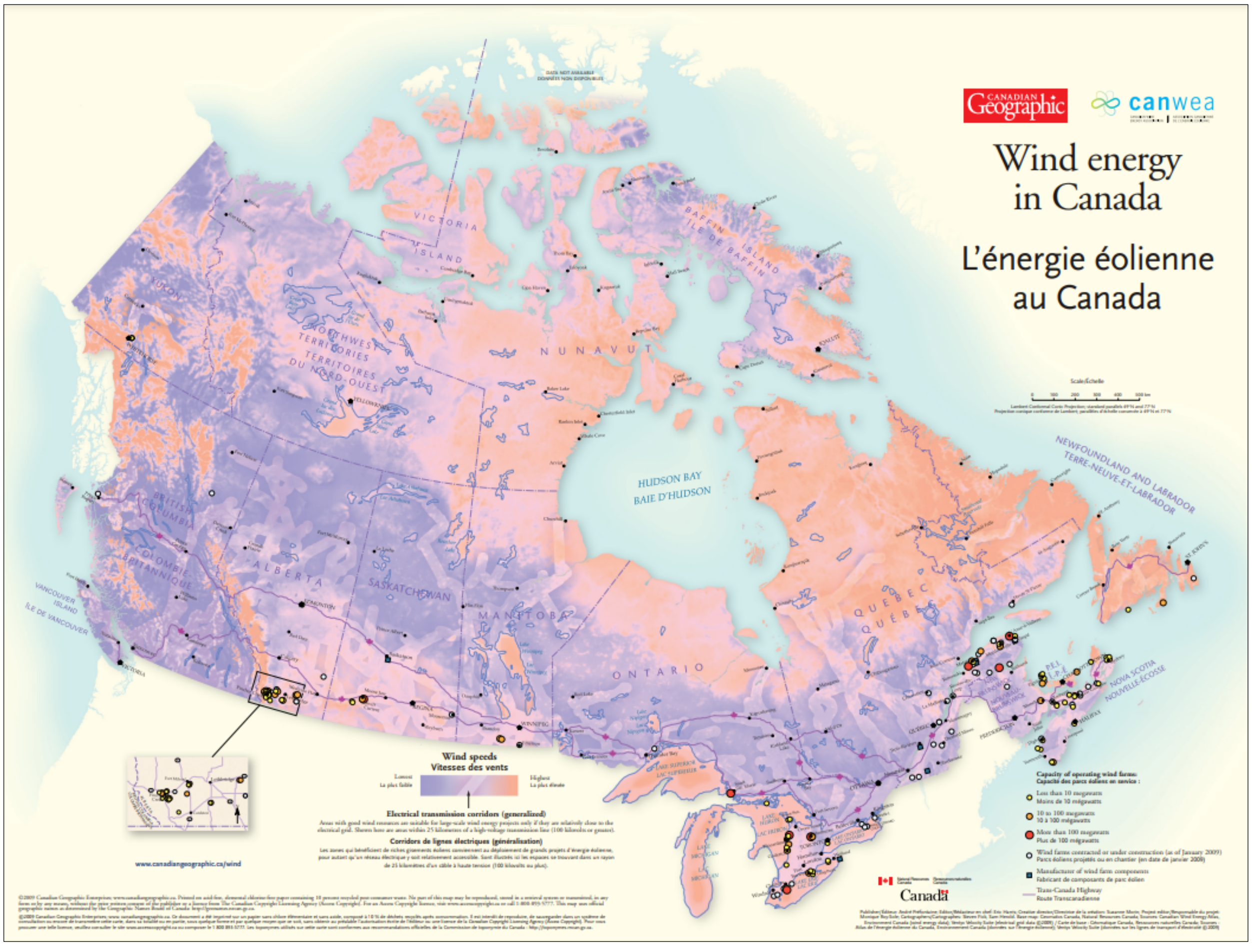
Wind generation utilizes moving air to rotate wind turbine blades which drive a generator. Wind turbines only provide power when the wind is blowing and represent one of the most highly variable sources of electricity. The use of asynchronous generator technology enables modern wind turbines to generate under a much wider range of wind speeds than was possible using older synchronous technology, and simultaneously removes the need for failure-prone gearboxes. There are many suppliers of wind turbines including Vestas and GE Energy, as well as manufacturers who specialize in arctic-rated systems, such as Aeronautica Windpower and Northern Power Systems. Southern Labrador has high wind energy potential, as illustrated by the following map from the Canadian Wind Energy Association ("CANWEA")

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Figure 7: Wind Energy Potential in Canada[35]



Note: A higher resolution of Figure 7 can be found in the **Error! Reference source not found.**.

Technical Viability	Dependable Capacity	Fuel Availability	Initial Screen result
High	No	Yes	Pass (for energy)

[35] Reference: https://natural-resources.canada.ca/sites/nrcan/files/canmetenergy/pdf/fichier/81770/windtrm_resource_map.pdf

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

6 COMBINING ENERGY RESOURCES WITH CAPACITY

Technologies deemed "viable" for both capacity and energy in Section 5 are used as building blocks to assemble the scenario alternatives evaluated for economic ranking in Section 7. Resources that are viable for economical energy generation but that do not provide firm capacity are not suitable for deployment as stand-alone supply for remote systems and must be coupled with some form of dependable capacity.

The technologies that were found to provide dependable capacity are thermal resources and storage hydro.

Thermal diesel generation is the status quo for NLH in remote systems. Compressed natural gas offers a potential fuel alternative with technical performance characteristics similar to diesel, but the associated transportation and storage requirement must be economically evaluated. A major cost driver for remote thermal generation is fuel cost.

If thermal technologies are utilized to provide dependable capacity, displacement of thermal fuel with cost competitive renewable energy resources offers a potentially viable approach for NLH to meet both its reliability obligations and its least cost mandate. Renewable technologies identified as potentially economically viable energy sources are wind, solar and hydro. This section explores the mechanics around offsetting fuel use with renewable resources. Renewable displacement of fuel is subsequently analysed economically in Section 7.

Development of a new storage hydro project for the Southern Labrador remote communities is economically and technically impractical. However, NLH has previously studied the option of linking these communities with the existing Labrador Interconnected System via a new transmission line, which would effectively power the communities using a large storage hydro resource. This capacity-energy solution is also assessed in Section 7.

Large battery systems represent another capacity resource increasingly being deployed to firm intermittent generation by bridging periods of fuel unavailability. A high-level economic analysis of large battery systems presented in this section confirms that this technology solution remains uneconomic for NLH.

6.1 Renewable Integration

Integrating renewable energy resources into a non-integrated system requires a dependable capacity backstop. For NLH this dependable capacity has historically been provided by diesel generation.

NLH has opportunistically displaced some of its diesel fuel use by incorporating renewable resources into its supply mix. In the Southern Labrador communities, NLH's approach has been and continues to be buying renewable energy from third part suppliers via a long-term Power Purchase Agreement (PPA).

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Evaluating the potential to integrate renewable energy resources into thermal based non-integrated systems involves answering two questions:

1. Can renewable energy resources compete on an energy cost basis with the marginal cost of diesel-based generation; and
2. What is the most economically appropriate model by which to procure the energy?

This IRP analysis considers that the most economically viable incremental renewable energy resources for development in Southern Labrador are wind and solar.

6.1.1 Cost

NLH has adopted a policy by which renewable energy, purchased through an PPA is done so at a cost of 90% of the marginal cost of diesel supply. As will be demonstrated in Section 8, the marginal cost of diesel generation is approximated at $330 per MWh (2023$).[36] Ninety percent of this cost is $297 per MWh. For the purposes of evaluating renewable integration, a PPA cost of $300 per MWh has been assumed. This proxy price is considered reasonable.

6.1.2 Procurement

There are at least three approaches that NLH can take to integrate renewable energy into its supply mix in Southern Labrador. These are:

1. Buy (provide electricity bill rebates) to users on the network who generate power through NLH's existing net metering program.
2. Purchase power from third parties using an PPA – this is the status quo approach, as NLH has previously offered and continues to pursue PPAs with qualified suppliers for renewable energy generation.
3. Develop / Own / Operate renewable generation resources - this approach would involve NLH undertaking development and ownership of its own renewable energy resources.

From the perspective of this IRP, the second approach has been assumed for the following reasons:

1. This is the status quo approach – NLH has systems in place to utilize this approach.
2. This approach insulates NLH from development risks and costs – Small independent development entities are more suited to small scale renewable development than are large, regulated utilities.

[36] Note: This is a complex, multivariate calculation taking into account not only fuel cost, but also system configuration and resultant variable O&M costs. For the purposes of this analysis, $330 / MWh is considered a reasonable approximation.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

3. Current Federal incentives and financial supports may enhance cost competitiveness of developments by specified groups wishing to undertake these projects.
4. Pursuing a policy of issuing PPA's to local developers and Indigenous groups aligns with NLH's policy goals of community and Indigenous engagement.

For the purposes of financially modelling renewable integration in Section 7, fuel displacement energy is modelled at an assumed PPA price of $300/MWh, with no associated capital or operating expense. In essence, it is assumed that this energy is procured from third party resources.

PPA contracts can be structured in at least two different ways:

The first PPA structure assumes "take-or-pay" by which the utility agrees to purchase all generated energy, regardless of its current load demand. This approach is often taken by utilities procuring energy for large integrated systems, since they are typically configured to either absorb or market all the energy procured. This structure is not preferred for a small remote system, since it could result in the utility procuring energy which it cannot use, which would have both technically and economically undesirable consequences.

A second type of PPA structure more conducive to small system applications places load risk onto the supplier by giving the utility the right to curtail production as required to match real-time demand less dependable capacity minimum production levels. Under this structure it is incumbent on the supplier to understand its revenue risk and adjust its proposed unit energy costs to support its capital carrying costs. This is the approach that NLH has historically taken and is considered the preferred approach, in part because diesel gensets need to operate at 30% or more of capacity or risk operational issues due to incomplete combustion of fuel known as "wet stacking" resulting in increased maintenance and emissions along with reduced operational efficiency.

At low levels of renewable penetration on the system, the risk of renewable generation curtailment under the second structure is low (although not negligible). As renewable penetration rises, and risks increase, then the presumed cost of renewable energy will also climb. This increase in cost is caused by either an allowance for curtailed generation, or the incremental revenue required to procure battery storage systems which can time shift some generation to when it is needed.

6.2 Batteries to Firm Capacity

NLH's Rural Planning Standard states:

> *"… wind and solar are considered as non-firm energy sources even when coupled with an energy storage system. That is, the wind and/or solar generation are not considered to provide firm capacity*

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

to the system during peak load. This is due to the random nature of the energy supply (wind/solar) which will not necessarily be present when it is needed.”[37]

For a remote isolated system in a challenging environment, this is considered a rational and prudent approach. However, with recent technology improvements, it is conceivable that a battery storage system supported by only renewable resources could be scaled to assure dependable service. The determinant therefore becomes one of cost.

Regardless of gradual unit cost decreases that have been observed over recent decades, battery systems remain economically impractical as a sole source of dependable utility-scale capacity for two reasons:

- Firstly, a system based solely on renewable resources requires significant surplus of installed renewable generating capacity because it must not only deliver the system load demand when fuel is available, it must also deliver surplus energy to the battery storage system during these same fuel availability periods. In addition, battery and inverter system losses mean that round trip (charge/discharge) cycle efficiency is less than unity – a battery system therefore represents a net load in excess of customer demand, and additional generation is required to supply these losses during the same periods of fuel availability.
- Secondly, battery systems large enough to bridge extended periods of renewable fuel “drought” are cost prohibitive, as discussed further below.

A simplified cost model was developed to demonstrate the economics of both a solar-battery hybrid system and a wind-battery hybrid system. This model forecasts the NPC of future cash flows (which is similar at a high level with the economic modelling detailed in Section 7). Common assumptions used in that model are summarized in Table 19.

It has been assumed that the four systems have been interconnected with the previously proposed 25 kV interconnection and voltage conversion to 25 kV distribution. There are a number of advantages to this interconnection including a smaller number of gensets in the southern Labrador communities, reduced operating costs by eliminating multiple generation facilities, and efficiencies to be realized by using larger, more fuel efficient gensets. There are additional benefits supporting interconnection of renewable energy projects along with the ability to increase renewable penetration because these renewables can be utilized across the entire network. Similarly, a cost has been ascribed to the decommissioning of the existing diesel systems. The model assumes implementation of the works occurs in 2024. Forecast loads and demand are all based on data from 2019 – 2020 and are consistent with forecast loads noted in Section 4.

[37] Hydro - Rural Planning Standard.pdf, page 4

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 19: Battery Supported Renewable - Model Assumptions

Financial	
Assumed Cost of Capital (real)	3.68%
Asset Life	20 years
Battery System Parameters	
Capital Cost – Storage ($/kWh)	$310
Capital Cost – Power ($/MW)	$290
Annual Cell Replacement Rate	5%
Annual Fixed O&M	$35/kW–yr.
Round Trip Efficiency	86%
Other Infrastructure	
25 kV Interconnection & Community Voltage Conversion	$38,000,000
Decommission Existing Diesel Stations	$880,000

NOTE: All costs in (2023$)

6.2.1 Wind with Battery "Dependable Capacity"

NLH has undertaken previous work to evaluate the wind potential of the Labrador coast. Published studies include:

1. Preliminary Assessment of Alternate Energy Potential in Coastal Labrador, NLH 2009; and
2. Coastal Labrador Wind Monitoring Program (Final Report), Hatch, 2015.

These reports provide some insight into the suitability of wind resources in the region and provide some insight into expected annual generation potential, neither provides a detailed view as to the maximum duration of expected gaps in generation by which one could appropriately size a dependable battery system.

To exacerbate this challenge, wind availability is stochastic in nature. Further production randomness is potentially introduced due to turbine icing events. Consequently, it is presumed that absent other sources of dependable capacity on the system, such as diesel gensets, significant battery storage would be required to assure reliable service.

NLH's Rural Planning Standard notes minimum onsite fuel for diesel stations with regularly delivered fuel to be sufficient *"such that the energy requirements of the system can be met* <u>*for two weeks*</u> *at all times of the year."* Developing fourteen days of battery storage is assumed to be economically impractical and, storage of only 24 hours would be insufficient to bridge calm periods.

In order to overcome the uncertainty of how much storage is enough, the economic model was run for battery storage options ranging from 1-day through 14-days, with other assumptions and calculated metrics summarized in Table 20.

Table 20: Wind-Battery Hybrid Model – Assumptions and Inputs

Battery System Parameters	
System Discharge Capacity	4 MW
Energy Storage	(Variable - see Table 21)
Capital Cost	(Variable - see Table 21)
Annual Fixed O&M	$140,000
Wind Generation Parameters	
Installed Capacity	14 MW
Capital Cost	$87,000,000
Capacity Factor	40%
Additional Losses	17%
Annual Generated Energy	40,500 MWh
Annual Served Energy	15,000 MWh

NOTE: All costs are noted in (2023$)

The results of the model are summarized in Table 21.

Table 21: Battery Supported Wind - NPC of Costs

Days Storage	Energy Storage (MWh)	Initial Capital Cost ($k)	Annual Cell Replacements ($k)	System NPC ($k 2023)
1	60	$20,000	$1,000	$188,000
2	120	$38,000	$1,900	$221,000
4	230	$73,000	$3,700	$280,000
6	340	$107,000	$5,400	$340,000
8	450	$141,000	$7,100	$400,000
10	560	$175,000	$8,800	$459,000
12	650	$203,000	$10,200	$508,000
14	760	$237,000	$11,900	$568,000

The financial analysis confirms that regardless of the storage period, a large-scale battery installation to convert wind energy to dependable capacity on an isolated system remains uneconomical.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

6.2.2 Solar with Battery "Dependable Capacity"

Solar energy potential is more predictable on a day-to-day basis than wind. A single system was modelled based on the energy demand from January 1, 2019, which was the highest full-day load recorded for the combined systems over the period from December 2019 to January 2020. A summary of the assumptions and inputs to and results produced by this model is presented in Table 22.

Table 22: Battery Supported Solar Energy Model – Assumptions, Inputs and Results

Battery System Parameters	
System Discharge Capacity	4 MW
Energy Storage	50 MWh
Capital Cost	$16,500,000
Annual Cell Replacement Cost	$830,000
Annual Fixed O&M	$140,000
Solar Generation Parameters	
Installed Capacity	43 MW
Capital Cost	$121,000,000
Capacity Factor	14%
Annual Generated Energy	54,000 MWh
Annual Served Energy	15,000 MWh
NPC of Future Costs	**$209,000,000**

NOTE: All costs are noted in (2023$)

The financial analysis confirms that the economics of large-scale battery installation to convert solar energy on a remote isolated system to dependable capacity remains untenable.

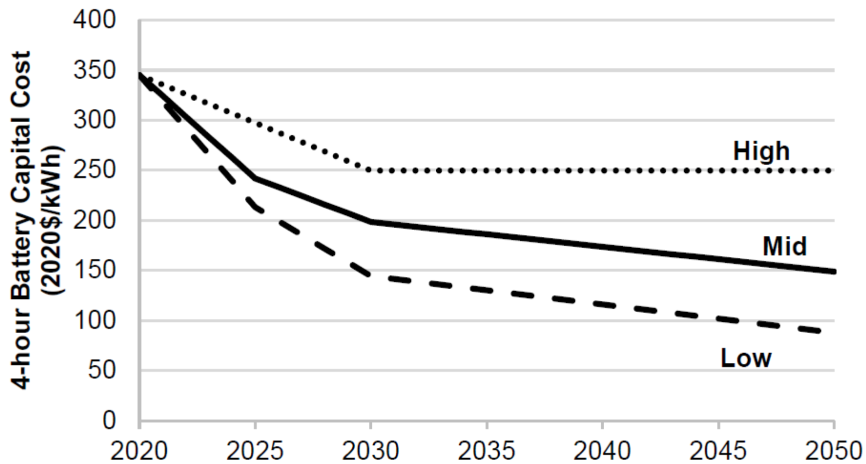
6.2.3 Analysis of reduced battery system costs

The cost of utility scale battery systems has been dropping over the last decade and a significant cost of the "renewable only" system costs were a result of battery storage systems. A brief analysis was undertaken to determine if the projected reductions in the cost of battery systems would make renewable systems cost competitive with thermal (Diesel or Natural gas) generation systems. Based on NREL data (figure reproduced below)[38] assuming that battery prices follow the most optimistic (low cost) curve, batteries will drop at most 70% in 25 years based on current 2022 costs. The largest price drops to be anticipated in the next 10 years would be approximately a 55% decrease in cost.

[38] Cole, Wesley, A. Will Frazier, and Chad Augustine. 2021. Cost Projections for Utility-Scale Battery Storage: 2021 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79236. https://www.nrel.gov/docs/fy21osti/79236.pdf.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Figure 8: Battery Cost Projections for 4-hour lithium-ion systems, with values relative to 2019
(The high, mid and low-cost projections developed in this work are shown as the bolded lines)



Based on this information it is not anticipated that renewable systems with battery firming will be cost competitive in the next decade, although some battery systems may prove useful for grid stability in the case of higher penetration of renewables. It is also notable that over the last year, battery prices have not significantly dropped, which may be partially attributable to temporary supply chain disruptions but is more likely a result of increased demand for raw materials (Lithium, Nickel, and Cobalt) which have dramatically increased in price over the last two years, with Lithium Carbonate increasing in price by more than ten times from November of 2021 to November 2022. While this price is currently on a downward trend, higher demand from major manufacturing areas including consumer electronics and the automotive sector is likely to continue higher price pressures on these materials.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

7 SCENARIO ANALYSIS

This section undertakes an economic analysis and ranking of supply scenarios that have been developed to reliably serve the six communities.

7.1 Scenario Description

Many scenarios were developed for evaluation. These were based on eight base scenarios and multiple sub-variations to account for different reliability metrics, development timing, etc. Scenarios were developed to satisfy three supply criteria. These were the provision of capacity, energy, and reliable back-up. The base scenarios are summarized in Table 23.

Table 23: Electrical Service - Source of Supply

Scenario	Firm Capacity	Energy[A]	Reliable Back-up
A – Maintain CHT Mobile Station	Diesel	Diesel / Renewables	Diesel
B – Construct new CHT Station	Diesel	Diesel / Renewables	Diesel
C – Interconnect Systems Immediately	Diesel	Diesel / Renewables	Diesel
D - – Interconnect Systems Immediately but Phase Existing Station Replacement	Diesel	Diesel / Renewables	Diesel
E - – Interconnect Systems Immediately but continue with disbursed generation stations	Diesel	Diesel / Renewables	Diesel
F – Phase interconnection and generation replacement	Diesel	Diesel / Renewables	Diesel
G[B] – Small Hydro	Diesel	Small Hydro + Diesel	Diesel
H[B] – Interconnection with Labrador Integrated System ("LIS")	Large Hydro (LIS)	Large Hydro (LIS)	Diesel

A. Analysis was carried out either with diesel generation alone, or with up to 50% penetration of renewable wind or solar procured through a PPA.
B. Both scenario G and H anticipate a lengthy permitting and construction lead-time which would necessitate an interim diesel solution to provide service until commissioned.

Note that in all scenarios, diesel generation facilities are required – at a minimum to provide reliable local back-up in the event of a transmission outage, but more generally, to overcome intermittency issues related to renewable energy generation. No scenarios included the use of large-scale battery storage as capacity, which was demonstrated in Section 6 to not be practical at this time.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

The eight core scenarios summarized in Table 24 are further differentiated into sub-scenarios applying the following configuration and phasing alternatives:

1. 25 kV Interconnection: Immediate Interconnection; phased interconnection; or no interconnection; and
2. Regional Plant: Immediate Regional Plant Generation; Delayed Regional Plant Generation; or no Regional Plant.

With the exception of large-scale battery storage, previously discussed, the identification of base scenarios able to provide a dependable source of capacity generally confirms previous alternatives identified by NLH as an appropriate. Table 24 provides further details on the base scenarios and correlates them to previous alternatives presented by NLH.

Table 24: Scenario Summary

IRP Scenario	NLH Scenario	Interconnection Option	Regional Plant Timing	Notes
A	1	None	None	Refurbishment of CHT Mobile Station (add building enclosure).
B	2	None	None	Construct new diesel plant in CHT.
C	3b	Immediate	Immediate	Decommission community plants in 2024.
D	7	Immediate	Phased	Defer Regional Plant until needed
E	6	Immediate	None	Continued disbursed community generation.
F	3a	Phased	Phased	Phased decommissioning of community plants.
G	5	Phased.	Immediate	Transition to capacity upon commission of small hydro.
H	4	Phased	Immediate	Transition to back-up upon commission of LIS interconnection.

These core scenarios were further sub-divided based on:

1. Different phasing of interconnection legs and generation alternatives;
2. Selection of either an "N-1" planning standard or the "N-2" planning standard assumed by NLH; and/or
3. Replacement of some diesel generation with natural gas.

A more detailed description of the scenarios analysis is presented in Table 25.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 25: Scenario Description

IRP Scenario	NLH Scenario	Description
A	1	This scenario contemplates the refurbishment of the CHT Mobile Station with the construction of a building enclosure and associated works to enhance reliability of the existing (remaining) mobile gensets. Each isolated community would continue to be serviced by its existing generating station. Diesel gensets would continue to be replaced as remaining useful life expires and the generating stations would be replaced sequentially (2030 for MSH; 2035 for PHS; and 2045 for SLE). Some work is required at MSH to extend that plant's life through 2030. Other planned capital work at each community plant continues as scheduled. Reliability planning continues to be to an N-1 standard. **Sub-variant:** • maximum displacement of 25% energy is assumed from renewables owing to minimum operating constraints on individual diesel engines and smaller load centres.
B	2	This scenario contemplates the construction of a new permanent generating station outside of CHT with an associated 2 km 4.16 kV interconnection to the existing distribution works. Each isolated community would continue to be serviced by its existing generating station. Diesel gensets would continue to be replaced as remaining useful life expires and the generating stations would be replaced sequentially (2030 for MSH; 2035 for PHS; and 2045 for SLE). Some work is required at MSH to extend that plant's life through 2030. Other planned capital work at each community plant continues as scheduled. Reliability planning continues to be to an N-1 standard. **Sub-variant:** • maximum displacement of 25% energy is assumed from renewables owing to minimum operating constraints on individual diesel engines and smaller load centres.
C	3b	This scenario involves 2024 construction of a Regional Plant near PHS, along with full 25 kV interconnection of all four systems plus 25kV voltage conversion in each distribution system. Existing community plants would be decommissioned in 2024. The Regional Plant would be built with 5-bays and installed with either 2x2220 kW, 2x1833 kW, and 1x1000 kW gensets for N-2 reliability; or 1x2220 kW, 1x1833 kW, 1x1000 kW, and 1x910 kW genset for N-1 reliability. Upcoming planned capital spend at each of the community plants is not undertaken. **Sub-variants:** • N-1 or N-2 reliability options • displacement of 50% energy by renewables is assumed, facilitated by the larger combined load and more extensive overhead wires footprint. • 1000 kW natural gas genset option, including associated fuel handling infrastructure and transport costs

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

IRP Scenario	NLH Scenario	Description
D	7	This scenario involves 2024 interconnection of the four systems plus 25kV voltage conversion in each distribution system. Existing generation at MSH, PHS and SLE is used to supply CHT until planned station retirement in 2030, 2035 and 2045 respectively. Necessary capital upgrades undertaken to extend MSH useful life until 2030. A 5-bay Regional Plant near PHS is deferred until 2030 and then installed with 2x1833 kW and 1x910 kW gensets. An additional 1833 kW genset is installed in 2035 and a 910 kW genset is installed in 2045. **Sub-variant:** • displacement of 50% energy by renewables is assumed, facilitated by the larger combined load and more extensive overhead wires footprint.
E	6	This scenario involves 2024 interconnection of the four systems plus 25kV voltage conversion in each distribution system, but continued reliance on the existing community based generating stations. No replacement station in CHT is planned. This allows a greater penetration of renewable resources and reduces excess gensets needed to achieve the desired reliability. Necessary plant Upgrade Life Extension ("ULE") works at the community stations would continue as scheduled in 2030, 2035 and 2045, respectively.
F		This scenario contemplates both a phased community interconnection and phased generation replacement, with the ultimate configuration comprising a Regional Plant near PHS and a 25 kV interconnected distribution system across all communities.
F(i)	n/a	Interconnect and convert CHT, PHS and MSH to 25 kV in 2024. Defer SLE interconnection and conversion until 2045. Construct 5-bay Regional Plant near PHS in 2024 and install with 1x2220 kW, 2x1833 kW, 1x1000 kW and 1x910 kW gensets for N-2 reliability. Decommission CHT, PHS and MSH in 2024 and SLE in 2045. Planned ULE work at SLE continues as scheduled. **Sub-variant:** • For N-1 reliability, no 1000kV genset and defer 910 kW genset until 2045. • displacement of 50% energy by renewables is assumed, facilitated by the larger combined load and more extensive overhead wires footprint.
F(ii)	3a	Interconnect and convert CHT and PHS to 25 kV in 2024 and MSH in 2030. Defer SLE interconnection and conversion until 2045. Construct 5-bay Regional Plant near PHS in 2024 and install with 1x2220kW, 2x1833kW and 1x910kW gensets in 2024 and 1x910kW in 2030. Decommission CHT and PHS in 2024 and MSH in 2030. Decommission SLE in 2045. Planned ULE work at SLE continues as scheduled. **Sub-variant:** • For N-1 reliability, the genset installation is as follows: 1x2220kV, 1x1833 kV and 1x1000 kV in 2024; and 1x910 in 2030. • displacement of 50% energy by renewables is assumed, facilitated by the larger combined load and more extensive overhead wires footprint.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

IRP Scenario	NLH Scenario	Description
F(iii)	n/a	Phased interconnection and voltage conversion with CHT and MSH connected in 2024, PHS in 2035 and SLE in 2045. Construction of a 5-bay Regional Plant in 2024. Install 1x2220kW, 2x1833kW, and 1x910kW genset in 2024. Install 1x910kW genset in 2035. **<u>Sub-variant:</u>** • displacement of 50% energy by renewables is assumed, facilitated by the larger combined load and more extensive overhead wires footprint.
G	5	This scenario contemplates the phased interconnection of all four systems to a regional small hydro facility (previously identified as Site 8C by Hatch). Each system would be converted to 25 kV when interconnected with the others. It is assumed that this scenario would take upwards of 10-years to approve, permit, design and construct, with full interconnection of all communities being completed in 2033. Upon completion of the hydro plant a diesel generating solution is still required to provide winter Firm capacity and back-up to the six communities. A Regional Plant 4-bay powerhouse is constructed in 2024 near PHS and interconnected to the CHT and PHS systems. The plant would be originally equipped with 2x1833 kW and 1x1000 kW gensets. The Regional Plant and existing PHS would combine to supply CHT and PHS. MSH would be upgraded and continue to operate through its planned end of life in 2030. At that time, an additional 910 kW genset would be installed at the Regional Plant and MSH would be converted to 25 kV service and interconnected. In 2033 SLE would be interconnected with the other three communities and converted to 25 kV. The Regional Plant would remain to provide back-up generation in the event of transmission outage.
H	4	This scenario contemplates the interconnection of the Southern Labrador communities to the Labrador Interconnected System via a transmission voltage interconnection previously studied by Hatch. This scenario involves 25 kV interconnection and voltage conversion of all four systems. It has been assumed that this full scenario would take upwards of 10-years to approve, permit, design and construct, with full interconnection occurring in 2033. Upon completion of the LIS transmission interconnection, a local diesel generating plant is still required to provide back-up to the four systems for loss of the interconnection. A Regional Plant 4-bay powerhouse is constructed in 2024 near PHS and interconnected to CHT and PHS. The plant would be installed with 2x1833 kV and 1x1000 kW gensets. The Regional Plant and existing PHS would combine to supply CHT and PHS. MSH would be upgraded and continue to operate through its planned end of life in 2030. At that time, an additional 910 kW genset would be installed at the Regional Plant and MSH would be converted to 25 kV service and interconnected. In 2033 SLE would be interconnected with the other three communities and converted to 25 kV. The Regional Plant would remain to provide back-up generation in the event of transmission outage.

7.2 Methodology

The relative ranking of the respective Scenarios is based on a lowest cost basis as determined through a discounted cash flow (“DCF”) model. In this analysis, non-cash impacts, such as accelerated depreciation of existing useful assets is ignored. The ranking is based solely on estimates of go-forward cash cost.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

The annual cash flows comprise staged capital spend, ongoing Operations and Maintenance ("O&M") costs and fuel costs. Capital costs include costs associated with new construction and supply as well as ongoing genset overhauls & replacements, tank inspections, and general capital spending planned for existing stations that remain in operation.

The DCF model begins in 2023 and runs through 2048 (26-years) which allows for planned capital works to commence in 2024 and run for a 25-year planning period. To account for different asset lives as well as deferred capital spending that would still retain some net book value at the end of the planning period, a "Terminal Value" allowance is appended to the end of the model, which comprises the residual un-used capital life assuming a straight-line depreciation. The Terminal Value is represented as a "negative cost" in the year 2049.

As noted previously, sub-variants of select scenarios allow for the displacement of a portion of diesel energy with purchased renewable energy. Inasmuch as the backbone of the installed system is required to provide dependable capacity, the NLH capital costs associated with these scenarios remain the same, with the only differences being cost of fuel and GHG emissions reductions. It is expected that there would be further savings through reduced engine use thereby forestalling genset replacement and modelled net book cost at the end of the planning period – which is generally scheduled based on engine runtime hours. This benefit would further enhance the predicted cost advantage of displacing diesel generation with renewable sources, but the model does not account for this benefit. This benefit is not expected to alter the results of this IRP.

7.3 Inputs and Assumptions

The inputs and assumptions used in the DCF Model include general financial and asset life assumptions, capital costs, operating costs, and fuel costs.

7.3.1 General Financial and Asset Life Assumptions

Cost of Capital

The assumed cost of capital is 5.75% (Nominal).

Inflation

The DCF Model is based on real-return, un-inflated 2023 costs. Predicting future inflation has become increasingly difficult in recent months. It is assumed that over the long-term, future cost escalation will generally revert to a long-term mean inflation target of 2%.

While the Canadian economy continues to experience higher than historic inflation, the published Bank of Canada target remains at approximately 2%. Consequently, future costs are discounted at the nominal cost of capital of 5.75% reduced to account for 2% inflation, or 3.68%.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

All previously generated cost estimates used in the model were escalated to January 2023 using historical Newfoundland & Labrador "All Items Consumer Price Index ("CPI")" as published by Statistics Canada.

Asset Life Assumptions

Net book value of assets is based on a straight-line depreciation of different asset classes are follows:

1. Diesel Plant – 35-years
2. Diesel Genset – 25-years
3. 25 kV Distribution Assets – 40-years
4. Periodic Fuel Tank Inspection – 10-years
5. Human Machine Interface/ Programmable Logic Controller (HMI/PLC)– 15-years
6. Small Hydro Plant – 60-years
7. LIS Transmission Assets – 60 years

7.3.2 Capital Costs

Capital costs used in the DCF Model are considered Class 5 according to the AACE Cost Estimate Classification System. Most capital costs are derived from cost estimates previously prepared by NLH and subsequently escalated to 2023 costs.

An independent check of select costs was undertaken and previous NLH costs estimates were deemed appropriate and location specific. Class 5 cost estimates are considered to be a suitable level of accuracy for this planning study.

Previously estimated capital costs were classified into several cost "buckets" which allowed a "building-block" approach to assembling different scenarios for evaluation. Cost buckets were derived from detailed costs previously estimated from NLH for six different alternatives. A general project overhead of 5% of fixed costs was applied to account for NLH costs that did not fit within specific cost buckets. Finally, an empirically estimated allowance of 5.7% of capital costs was added to account for Interest During Construction ("IDC") and 10% contingency was applied to all fixed costs.

Powerhouse and generator cost "buckets" are summarized in Table 26.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 26: Powerhouse Capital Costs

Cost Component	Cost (2023$)
<u>Powerhouse</u>	
PH - Fixed	$3,380,000 ea.
PH Bays - Variable	$1,560,000 per bay constructed
PH Genset - Variable	$140,000 per generation installed
Fire Suppression – Fixed	$2,300,000 ea.
Incremental PH Cost for Natural Gas[A]	$170,000 per bay
CNG Storage Tank - Small[A]	$79,000
CNG Storage Tank - Large[A]	$205,000
MSH PH Life Extension	$810,985 ea.
Upgrade CHT Mobile Station	$11,500,000 ea.
<u>Generators</u>	
Genset <= 600 kW	$980,000 ea.
Genset 800 kW	$1,140,000 ea.
Genset 910 kW	$1,180,000 ea.
Genset 1000 kW	$1,250,000 ea.
Genset 1833 kW	$2,080,000 ea.
Genset 2220 kW	$2,410,000 ea.
Genset – Variable	$900,000 per genset installed

A. Incremental powerhouse costs for using compressed natural gas ("CNG") as a substitute fuel were developed independently of NLH and comprise costs primarily for fire suppression, gas monitoring, fuel storage and fuel handling.

Overhead wires and other distribution capital costs are summarized in Table 27.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 27: Distribution Capital Costs

Cost Component	Cost (2023$)
Switchyard	
Recloser - Variable	$70,000 ea.
Generator Step-up Transformer (25 kV)	$1,180,000 ea.
Distribution Wires	
4.16 kV Tx - 2km	$820,000 lump sum
25kV Tx - SLC-COM-PHS - 3km	$920,000 lump sum
25kV Tx - SLC-COM-CHT - 50km	$12,630,000 lump sum
25kV Tx - SLC-COM-MSH - 50km	$12,910,000 lump sum
25kV Tx - SLC-COM-SLE -30km	$7,270,000 lump sum
25kV Tx - Hydro 8C - PHS -13km	$3,330,000 lump sum
Community Work	
CHT Voltage Conversion	$320,000 lump sum
MSH Voltage Conversion	$370,000 lump sum
PHS Voltage Conversion	$240,000 lump sum
SLE Voltage Conversion	$190,000 lump sum

Finally, decommissioning costs for existing stations are summarized in Table 28.

Table 28: Existing Station Decommissioning Costs

Station Decommissioning	Cost (2023$)
CHT - Partial	$200,000
CHT – Full	$240,000
MSH - Partial	$200,000
MSH - Full	$240,000
PHS - Partial	$180,000
PHS – Full	$220,000
SLE - Partial	$150,000
SLE - Full	$180,000

Capital costs for the Small Hydro project site 8C were based on the Hatch 2012 report. Hatch originally estimated an all-in capital cost of $62 million (2012$). This cost was not inclusive of community interconnection but did include placeholder transmission costs from the hydro powerhouse to the proposed NLH 25 kV system. For the purposes of this IRP, the transmission costs were deducted from the Hatch estimate. The previously indicated 5.7% of capital costs was added to allow for IDC. These costs were then escalated to 2020 (2020$) using N&L All Items CPI.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

An allowance for development costs of 10% was then added and a fixed cost of $7 million for environmental mitigation, as was previously estimated by NLH. Finally, the total cost was escalated to 2023$. The revised estimated capital cost of the Small Hydro alternative, not including transmission & distribution is $100,740,000.

A similar approach was used for the Southern Labrador Interconnection, wherein select Hatch costs, as summarized in Table 29, were escalated to 2023$.

Table 29: Hatch Southern Labrador Interconnection - Select Costs

Hatch Cost Item	Cost (2020$)
Transmission Lines	
HV-GB to Muskrat Falls Intersection	$204,000,000
Muskrat Falls Intersections to CHT Tap	$49,300,000
CHT Tap to PHS	$17,516,000
Substations	
Muskrat Falls Intersection	$9,800,000
PHS	$7,400,000
Reactive Power Compensation	
Muskrat 138 kV	$483,000
TOTAL	**$288,499,000**

Hatch notes that costs include overhead and contingency though no further detail is provided. Hatch further notes that land acquisition costs are not included. For the purposes of this IRP, no further allowance has been added for overhead or contingency, however, a 5.7% allowance has been included for IDC. No allowance for land acquisition costs has been estimated or applied. The total estimated cost for this alternative, not including community interconnections and voltage upgrades is $338 million (2023$).

Replacement costs for specific gensets currently in use were estimated by NLH in 2020$. These costs were escalated to 2023$ as summarized in Table 30.

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 30: Select Genset Replacement Cost

Genset Size (kW)	Replacement Cost (2023$)
200 / 250	$1,880,000
300	$2,110,000
500	$2,440,000
545	$2,440,000
600	$2,770,000
725	$3,100,000
910	$3,100,000
1000	$3,660,000
1500	$4,320,000
1800	$4,650,000
2200	$5,100,000

7.3.3 Operating Costs

Operating costs for each genset class and station were provided by NLH in 2020$ based on past metrics. These costs were escalated to 2023$ and applied to the respective genset / station. Below is a summary of average O&M costs used:

1. Variable Genset O&M ($0.056/kWh)
2. Fixed Generating Station O&M ($342,000/station/year)
3. Transmission / Distribution Overhead Line Maintenance ($1,399/km/year)
4. Tank inspection ($250,000 ea.)
5. HMI Replacement ($1,000,000 ea.)
6. Genset overhaul ($110,000 to $610,000 per overhaul)

7.3.4 Fuel Costs

<u>Diesel</u>

NLH provided a Southern Labrador fuel cost forecast with an embedded implied general escalation to account for inflation. Because the DCF Model uses escalated costs in 2023$, it was necessary to net out that escalation using an assumed future CPI of 2%. The resulting adjusted fuel cost forecast is shown in Table 31.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 31: Fuel Cost Forecast

Year	NLH Diesel Forecast ($/L)	Assumed CPI	Compound CPI	Diesel Forecast net of CPI (2023$)
2023	$1.845	7.01%	7.01%	$1.724
2024	$1.669	2.00%	9.15%	$1.529
2025	$1.660	2.00%	11.33%	$1.491
2026	$1.570	2.00%	13.56%	$1.383
2027	$1.465	2.00%	15.83%	$1.265
2028	$1.430	2.00%	18.15%	$1.210
2029	$1.395	2.00%	20.51%	$1.158
2030	$1.390	2.00%	22.92%	$1.131
2031	$1.400	2.00%	25.38%	$1.117
2032	$1.405	2.00%	27.89%	$1.099
2033	$1.415	2.00%	30.44%	$1.085
2034	$1.430	2.00%	33.05%	$1.075
2035	$1.450	2.00%	35.71%	$1.068
2036	$1.480	2.00%	38.43%	$1.069
2037	$1.505	2.00%	41.20%	$1.066
2038	$1.540	2.00%	44.02%	$1.069
2039	$1.570	2.00%	46.90%	$1.069
2040	$1.605	2.00%	49.84%	$1.071
2041	$1.640	2.00%	52.84%	$1.073
2042	$1.680	2.00%	55.89%	$1.078
2043	$1.710	2.00%	59.01%	$1.075
2044	$1.745	2.00%	62.19%	$1.076
2045	$1.780	2.00%	65.43%	$1.076
2046	$1.820	2.00%	68.74%	$1.079
2047	$1.860	2.00%	72.12%	$1.081
2048	$1.860	2.00%	75.56%	$1.059

Remote community diesel generation is currently exempt from provincially or federally imposed carbon taxes. Should that policy change, the result would be an increase in the cost of diesel, which is discussed in Section 8 – Sensitivity Analysis.

The fuel consumption per kWh of generation for existing generation was reported by NLH based on past operating metrics. Average historical consumption was 0.28 L/kWh – new gensets are forecast to have better efficiency, with an assumed consumption of 0.25 L/kWh. The fuel consumption per kWh of generation for existing generation was reported by NLH based on past operating metrics. Average historical consumption was reported as 0.29 L/kWh. Replacement gensets in the isolated plants are forecast to have average 0.28 L/kWh. New gensets for a regional plant are forecast to have better efficiency, with an assumed consumption of 0.25 L/kWh.

Natural Gas

The closest source of pipeline natural gas was determined to be Saguenay. The cost (2023$) for delivered CNG to PHS was quoted by a local supplier to be $17,600 ($5,600 supply and $12,000 delivery) for a 350 Gigajoule ("GJ") truck, or $50/GJ.

Based on quoted efficiency, natural gas consumption is estimated to be 10.39 GJ/MWh.

IPP Renewable Energy

As discussed in Section 6.1.1, the marginal energy cost for renewable energy from local wind and solar resources is assumed to be $300 per MWh.

7.4 Results and Analysis

Table 32 shows the ranking by NPC of all future costs of the different core scenarios, prior to incorporating savings from renewable energy procurement or using an N-1 planning standard.

Table 32: Ranked Scenarios - No Renewable Procurement / N-2 Reliability

Rank	Scenario	NPC ($k 2023)	Increment from Least Cost ($k 2023)
1	C	$165,200	$0
2	F(i)	$172,100	$6,900
3	F(ii)	$174,700	$9,500
4	A	$177,400	$12,200
5	F(iii)	$179,400	$14,200
6	D	$182,000	$16,800
7	B	$185,200	$20,000
8	E	$189,100	$23,900
9	C + Natural Gas	$198,800	$33,600
10	G	$212,900	$47,700
11	H	$292,500	$127,300

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

The ranking process was repeated after incorporating savings from solar and wind procurement, with results summarized in Table 33.

Table 33: Implied Cost Savings from Renewable Procurement Offset of Diesel

Rank	Scenario	NPC No Renewables ($k 2023)	NPC with Renewables ($k 2023)	Implied Cost Advantage from PPA Renewables ($k 2023)
1	C	$165,200	$162,400	$2,800
2	F(i)	$172,100	$169,100	$3,000
3	F(ii)	$174,700	$171,800	$2,900
4	A	$177,400	$174,500	$2,900
5	F(iii)	$179,400	$176,500	$2,900
6	D	$182,000	$178,200	$3,800
7	B	$185,200	$182,300	$2,900
8	C + Natural Gas	$198,800	$183,200	$15,600
9	E	$189,100	$184,600	$4,500
10	G	$212,900	$212,900	$0
11	H	$292,500	$292,500	$0

Finally, NLH previously applied an N-2 standard when planning its Regional Plant, which analysis in Section 4.4.1 suggests will reduce EUE by 8 MWh annually. The ranking change attributable to accounting for the savings achieved by switching to an N-1 planning standard for the Regional Plant is nil, as shown for the relevant scenarios in Table 34.

Table 34: N-2 to N-1 Cost Savings

Rank	Scenario	NPC with Renewables ($k 2023)		Cost Difference ($k 2023)
		N-2	N-1	
1	C	$165,200	$161,100	$4,100
2	F(i)	$172,100	$166,400	$5,700
3	F(ii)	$174,700	$170,800	$3,900
10	C + Natural Gas	$198,800	$194,300	$4,500

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table 35 shows the overall final ranking of all scenarios and sub-variants in a single table.

Table 35: N-2 to N-1 Cost Savings

Rank	Scenario	NPC ($k 2023)	Increment from Least Cost ($k 2023)
1	C (N-1) + Renewables	$158,300	-
2	C (N-1)	$161,100	2,800
3	C + Renewables	$162,400	4,100
4	F(i) (N-1) + Renewables	$163,400	5,100
5	C	$165,200	6,900
6	F(i) (N-1)	$166,400	8,100
7	F(ii) (N-1) + Renewables	$167,900	9,600
8	F(i) + Renewables	$169,100	10,800
9	F(ii) (N-1)	$170,800	12,500
10	F(ii) + Renewables	$171,800	13,500
11	F(i)	$172,100	13,800
12	A + Renewables	$174,500	16,200
13	F(ii)	$174,700	16,400
14	F(iii) + Renewables	$176,500	18,200
15	A	$177,400	19,100
16	D + Renewables	$178,200	19,900
17	C (N-1) + Natural Gas + Renewables	$178,700	20,400
18	F(iii)	$179,400	21,100
19	D	$182,000	23,700
20	B + Renewables	$182,300	24,000
21	C + Natural Gas + Renewables	$183,200	24,900
22	E + Renewables	$184,600	26,300
23	B	$185,200	26,900
24	E	$189,100	30,800
25	C (N-1) + Natural Gas	$194,300	36,000
26	C + Natural Gas	$198,800	40,500
27	G	$212,900	54,600
28	H	$292,500	134,200

The preferred scenario alternative is Scenario C, which involves immediate construction of a Regional Plant to serve all four systems via a new 25kV interconnection, with associated 25 kV voltage upgrades in all communities. No NPC savings are forecast to be achieved by deferring a portion of the interconnection process.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Three key factors driving this result relative to NLH's previous recommended Phased implementation of the interconnection are:

1. Time has passed since the prior analysis was completed and the planned replacement of the MSH plant is closer than when initially modelled. This reduces any cost benefit attributable to deferral of those costs.
2. Further unplanned deterioration of the plant at MSH necessitates material capital spending to extend the life of that facility through to 2030.
3. Increased forecast diesel costs favour scenarios with higher efficiency, such as a regional plant, and increased renewable procurement. The fully interconnected system configuration facilitates increased penetration of incremental renewable energy resources.

Conclusions:

1. Preferred Scenario C involves immediately constructing a Regional Plant to an N-1 planning standard, interconnecting all four systems, and upgrading to 25 kV in each community.
2. Retaining NLH's existing local mobile generation fleet will mitigate any incremental risk associated with applying the N-1 planning standard to the Regional Plant. These mobiles can also be deployed to provide backup service to individual communities in the event of an extended outage on the 25 kV interconnection system by procuring a mobile or skid-mounted 4/25 kV Generator Step-up Transformer ("GSU") station.
3. NLH should proceed with efforts to support and procure incremental low-cost renewable energy supplies.

7.5 GHG Emissions Analysis

Although GHG emissions are not a metric against which NLH is currently mandated to plan, a secondary analysis was undertaken to estimate the relative GHG emissions of the different scenarios. For this analysis, the cumulative total litres of diesel and GJ of natural gas consumed over 25 years in each of the applicable scenarios was converted to an equivalent emission in terms of tonnes of CO_2. The following conversion factors were assumed for this analysis:

1. 2.7 kg of CO_2 per L of diesel consumed; and
2. 50 kg of CO_2 per GJ of natural gas consumed.

Only those scenarios with cumulative CO_2 emissions less than the preferred scenario (C (N-1) + Renewables) are included in this analysis. This shows an implied cost per tonne of avoided CO_2 emissions for those scenarios with less emissions than the preferred scenario. This analysis is presented in Table 36.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1 **Table 36: Comparable Cost of CO_2 Emission Savings**

Rank	Scenario	Total Emissions (t CO_2)	NPC ($k 2023)	Implied Cost per tonne of CO_2
1	H	123,000	$292,500	$4,000
2	G	133,000	$212,900	$2,000
3	C (N-1) + Natural Gas + Renewables	143,000	$178,700	$1,000
4	C (N-1) + Renewables	161,000	$158,300	$0

2 This analysis suggests that, although the interconnection of the Southern Labrador system appears friendly
3 from a GHG emissions perspective, the implied cost per tonne of reduced CO_2 is orders of magnitude above
4 currently accepted pricing for emissions. It further suggests that any subsidies that could be applied to
5 reduce the cost of this scenario would, from a pure cost of carbon perspective, be better applied to solutions
6 with a more favourable cost-benefit ratio, such as incremental renewable resource additions in Scenario C.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

8 SENSITIVITY ANALYSIS

The preceding analysis concluded that the preferred scenario for NLH to pursue is the immediate construction of a Regional Diesel Plant interconnected via a 25 kV system to each of the four systems. Both cost and future CO_2 emissions of this scenario are reduced through a recommended purchase of wind and or solar generated renewable energy from a third party through an PPA.

A sensitivity analysis was carried out to confirm the robustness of that conclusion in the face of inherent uncertainties associated with selected analysis inputs. The inputs selected for the sensitivity analysis were:

1. Assumed PPA cost of renewable energy above $300/MWh.
2. The cost of diesel – factored at a fixed percentage.
3. The application of forecast carbon pricing to NLH's currently exempt diesel fuel supply.
4. Regulated Real Returns – some scenarios, including the preferred scenario – entail significant up-front capital costs (driven by the cost of the 25 kV interconnection) which offsets potentially higher future O&M and fuel costs associated with lower upfront capital cost alternatives. To the extent that NLH's regulated real rate of return increases materially as compared to future costs (an unlikely scenario), then any scenario that involves significant up-front capital spending could change.
5. Changes in the capital cost of interconnection work (overhead wires and voltage conversion) against no increase in generation capital costs. Although it is expected that utility construction and procurement costs would generally escalate consistently across asset classes, the preferred scenario is characterized by relatively high overhead wires cost. A change in this parameter could alter the results.
6. Changes in the relative cost of O&M versus capital cost. The preferred scenario is characterized by higher up-front capital costs offset by significant savings in future O&M, overhaul and replacement costs at the existing generating facilities.
7. Penetration of renewables / uptake in renewables PPA – the DCF assumed 50% energy generation from renewable generation for an interconnected system compared with only 25% for isolated systems. Both assumed that this would be achieved by 2028, to allow sufficient lead time for the development and contracting of the resources. Changes in these relative metrics are not expected to alter expected capital expenditures – but may influence the overall ranking of the scenarios.

Certain factors were not included in the sensitivity analysis for the following reasons:

1. Allowance for inflation – the DCF model is predicated on real returns. If future cost increases of any inputs are reflected in future nominal regulated cost of capital, then future changes in inflation are irrelevant to this analysis. This assumes that the "basket of goods" that comprise future NLH costs all generally escalate at inflation. Over the long term this is expected to be a reasonable assumption.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

2. Changes in future load – load has been demonstrated to be reasonably flat over the past decade. The preferred Regional Plant alternative – which assumes an N-1 reliability metric – assumes a pre-constructed extra bay in the Regional Plant – which would allow reasonably low-cost addition of an additional genset to address Firm capacity for peak demand growth. Future load growth is therefore able to be addressed as and when it occurs. On a $ per kW served, the incremental costs would be partially offset with incremental energy sales revenues. Finally, load growth driven by fuel switching can be addressed through DSM opportunities. Decreases in future load would simply reduce diesel use while not alleviating NLH from securing requisite capacity resources in the near term. While a phased approach would potentially shelter NLH from this risk, the cost differential of $5 million between the recommended scenario and the least-cost phased scenarios is considered a significant cost to protect against future uncertainty.

Each of the included metrics were levered individually until the preferred scenario changed. The input, percentage change, new preferred scenario, and qualitative assessment of likelihood of the modeled outcome are all presented in Table 37.

Table 37: Sensitivity Analysis Results

	Change Variable	% Change	Original Value	New Value	Least Cost Scenario After Change	Likelihood
1	Cost of Renewables	+10%	$300 / MWh	$330 / MWh	C (N-1)	Low
2	Increase of Future Diesel Fuel Cost	+140%	$1.16 /L	$2.79 /L	C (N-1) + Renewables + Natural Gas	Low
3	Application of Carbon Tax[A]	-	$1.16 /L	$1.68 /L	No change	
4	Regulated Real Rate of Return	+139%	3.68%	8.79%	A + Renewables	Low
5	Diesel Plant Capital Cost	+663%	$19M / plant	$129M / plant	D + Renewables	Low
6	Diesel Plant O&M	-	-	-	No change	
7	Interconnection Capital Cost	+54%	$34.9 million	$53.7 million	A + Renewables	Low
8	Overhead Wires Annual O&M	+539%	$1,400/km	$8,900/km	A + Renewables	Low
9	Penetration of Renewables – Interconnected Load		50%	0% to 100%	No change	
10	Penetration of Renewables – Isolated Loads		25%	0% to 100%		

A. Assumed to be ($/L): 2023 - $0.17; 2024 - $0.21; 2025 - $0.25; 2026 - $0.30; 2027 - $0.34; 2028 - $0.38; 2029 - $0.42; and 2030+ - $0.46

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Based on the analysis, it is concluded that the recommended scenario is robust and offers NLH a reasonably assured reliable, least-cost path forward to address the needs of the Southern Labrador communities.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

9 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

Ongoing operational challenges with the current temporary configuration of the CHT system necessitate a timely permanent solution. Evolving societal opinions and the regulatory response do not alter this. Based on the analysis in this study, the following conclusions are made:

Need for Capacity

1. The six southern Labrador communities are served by small isolated systems that preclude reliance on large integrated system for provision of dependable capacity. The interconnection of these systems to the Labrador Interconnected System is shown to be uneconomic. Maintaining Firm capacity is required for NLH to meet its mandate for safe and reliable service.
2. Regardless of what generation source provides energy to the system, diesel generation is currently the least cost dependable capacity resource. Regardless of changes in climate policies, and despite technological advances and cost decreases in utility scale battery storage systems, a fully renewable / battery supported system is currently uneconomic, and cost projections suggest that this will remain the case at least for the near term (next 10 years) so it is reasonable to plan for a diesel-based network and re-evaluate technologies as part of planning for units as they age out of use.

Consistent with Other Jurisdictions:

3. Use of diesel gensets to provide dependable capacity to remote isolated loads remains consistent with other like jurisdictions across Canada.

System Interconnection:

4. Interconnecting the four systems and six communities will incur a significant upfront capital cost. Analysis suggests that this cost would be more than offset by operational savings over the (relatively short) 25-year period of analysis.
5. The interconnected system also allows NLH to maintain service reliability with fewer overall gensets, which also provides capital cost savings to offset the cost of interconnection.
6. The interconnection does result in a nominal increase in Expected Unserved Energy from potential outages on the 133 km of overhead line. This can be offset by incorporating an N-2 planning reserve at the Regional Plant and incorporating an additional genset. This approach does not address outage risk on the overhead lines but does reduce unreliability from loss of supply.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Renewable Energy Procurement:

7. Fuel price risk and GHG emissions can both be offset by supplementing diesel generation with intermittent renewable energy. Current funding support programs and past experience suggest that the preferred approach to obtaining renewable energies is through PPAs with third parties. Existing federal programs targeted at Indigenous groups suggest that these groups will be able to provide renewable energy at a cost lower than NLH can, so this meets the "lowest cost" requirement as well as meeting several Indigenous and local community policy objectives.
8. At low levels, the integration of renewable resources into a diesel-backed system is straight forward. As the penetration of renewables into the system increases, operational challenges associated with maintaining sufficient spinning reserve, the minimum turn-down of diesel gensets, and throttling to maintain constant voltage, can be ameliorated with the use of battery storage systems. The necessity and the cost effectiveness of a storage system can be evaluated at the time of contracting the resource.

Alternate Fuels:

9. Alternate thermal generation fuels (i.e., compressed natural gas, liquified natural gas bio-diesel, and hydrogen) are not currently cost effective for a system of this scale, operating climate and distance from fuel supplies.

9.2 Recommendations

Based on those conclusions, the following recommendations are made for the consideration of NLH:

1. **NLH pursue the preferred Scenario C, which involves immediately constructing a Regional Plant to an N-1 planning standard, interconnecting all four systems and upgrading to 25 kV in each community.** Although the roll out of this can be phased, this study suggests there are economic benefits to its immediate full implementation. Regardless of phasing, priority is needed for the supply of power to Charlottetown, which has been operating with a temporary configuration for several years.
2. NLH minimize future reliance on mobile gensets to supply baseload energy and capacity.
3. NLH use an N-1 reliability for Loss of Supply in its generating plants. The existing local mobile generation fleet can be deployed to mitigate any incremental risk associated with outages on the overhead lines. These mobile gensets can be deployed to provide backup service to individual communities in the event of an extended outage on the 25 kV interconnection system by procuring a mobile or skid-mounted 4/25 kV GSU transformer station.
4. NLH proceed with efforts to support and procure incremental low-cost renewable energy supplies.

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

5. NLH consider a deeper study of DSM measures in the communities, particularly on avoiding fuel switching from Fuel oil or wood to electrical heating systems. Additional information on the prevalence of resistive electric heating in southern Labrador is required to evaluate its replacement with high efficiency heat pumps.
6. As gensets are scheduled for retirement, evaluate new technologies prior to deciding on replacement of units with similar systems.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

APPENDIX A: DEMAND SIDE MANAGEMENT OPPORTUNITY

A.1 Introduction

A purposeful reduction in load through the deployment of energy efficient technologies and the introduction of energy conservation initiatives has come to be called "Demand Side Management" ("DSM"). In and of itself, this purposeful reduction can be considered a "resource" similar a new source of generation since both have the same effect of reducing the gap between supply and demand. As a result, a cost-effective program that encourages less energy use (for the same customer satisfaction) can be compared against new generation sources. It should be noted that there have been three major studies undertaken on DSM measures for NLH in the last decade, "Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015", "Newfoundland and Labrador Conservation Potential Study (2020-2034)", and "2021 Electrification, Conservation and Demand Management Report". These studies are largely focused on opportunities present in the major load centers: Newfoundland centered on the Avalon peninsula and the Labrador Interconnected System (LIS). While some of the findings in these reports, particularly on residential demands are applicable to southern Labrador, a review of DSM potential specific to the southern Labrador communities is recommended as part of the IRP.

It should be noted that these three studies were generally organized to cover Newfoundland (the island), the Labrador Interconnected System and isolated systems. Our focus in this report is on southern Labrador, which is an isolated system.

A.2 Background and Overview

Managing the demand-supply balance from the load (i.e., customer) side is known as Demand Side Management ("DSM").

There are two fundamentally different approaches to DSM. The first is comprised of a reduction of peak demand, which can flatten the load curve and generally result in more efficient use of existing generation assets (i.e., less idle capacity of those resources). A reduction in peak demand is a "Demand Response" DSM measure.

The second approach is an overall reduction of energy use, regardless of timing. This approach, while not driving toward a more efficient use of existing generation assets, may forestall the need for new assets, or displace the need for expensive (or from a climate concerned perspective, lower GHG generating) generation. A system put in place to affect energy efficiencies and reduce overall energy use is known as an "Energy Efficiency" DSM measure.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

A.2.1 Demand Response ("DR")

Demand Response (or demand reduction) can be considered to be similar to the procurement of a new generator, but instead of buying a piece of equipment that needs to be fueled and maintained, the "purchase" is in the form of an incentive to a large power user to not use power at a specific time. The cost of an agreement to reduce demand at peak hours (often less than the top 5% of peak hours) is often less expensive than the marginal cost of new system assets. Put another way, an agreement to curtail operations for 400 hours a year is often less than the cost of buying additional generation assets that will operate 400 hours a year, and many DSM agreements represent curtailment periods of less than 100 hours per year. An example of this type of demand reduction might be an agreement with an aluminum smelter to reduce its energy usage during peak hours in exchange for a contract payment.

The second common form of DR is the use of incentive-based pricing tiers for peak and off-peak periods, which indirectly encourage customers to reduce their energy usage during peak hours. An example of this type of demand reduction might be increased power pricing for consumers during the afternoon peak hours, in the hope that customers respond to this pricing signal by reducing their energy consumption during specific periods (e.g., by delaying the use of non-critical appliances like dishwashers and dryers until non-peak hours).

A.2.2 Energy Efficiency ("EE")

To achieve a reduction in overall energy use, utilities can establish programs that encourage the use of technologies that provide a similar or increased benefit but with less energy use. Energy Efficiency incentives are typically used to either reduce load growth or the marginal cost of generation. An example of load growth reduction would be subsidizing the cost of LED lightbulbs or heat pumps to replace incandescent or resistive heating systems and reducing these loads while still meeting the same lighting or heating needs. An example of reducing marginal cost of generation would be encouraging use of power during daylight hours for a system that incorporated a solar generation system, since solar arrays do not use fuel to operate.

While this strategy also nominally reduces peak demand, the impact is more board and spread over the daily cycle, and as such is better thought of as reduction of energy use rather than reduction of peak capacity. Energy efficiency measures are seldom enough to reduce the peak loads enough to offset the requirement to add additional generation assets: their main benefit is an incremental reduction of the demand curve along with a larger reduction of energy generation.

A.3 Assessment of Potential DSM for Southern Labrador Communities

NLH has a number of existing programs in place for DSM including both Demand Response and Energy Efficiency, which are largely tailored for the larger communities and industrial demands present in Newfoundland. Southern Labrador is significantly different in terms of industry, geography and population

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

density to the majority of NLH's systems. NLH has a number of specific programs that have been active in Southern Labrador since 2012 which include direct installation of energy efficient technologies. The opportunities and challenges inherent in DSM measures must be evaluated in the context of Southern Labrador, rather than NLH's overall operations.

A.3.1 Demand Response

Three potential strategies for demand response were identified as part of the analysis of Southern Labrador. These are:

1. Combining the four currently separated load systems into a single unified system;
2. Employing curtailment agreements with large users; and
3. Encouraging broader energy use patterns.

A.3.1.1 Interconnection of Islanded Systems to Reduce Aggregate Peak Load

As noted in the main body of the Integrated Resource Plan southern Labrador's six communities experience peak loads at different times of the year. The largest individual consumers of power in the Southern Labrador communities are the seafood processing plants located in Charlottetown and Mary's Harbour. These facilities have large seasonal (summer) loads which are tied to the respective fisheries. In contrast, Port Hope Simpson and St. Lewis, which are predominantly residential in nature, currently exhibit moderate winter peaks, associated with residential heating and lighting.

Interconnecting the electrical grids of the six communities results in a significantly lower overall peak load than the sum of the community's peak loads. This is explored in detail in the IRP, and the load reduction allows fewer, larger generators to operate and meet the same overall level of service. This is technically a demand response measure and thus needs to be outlined in this appendix, although the implications are significantly larger than simply reducing the peak load, so this is covered in more detail in the IRP.

A.3.1.2 Curtailment Agreements

The only major loads that could be considered for curtailment agreements would be with the seafood processions plants. An agreement of this type would allow curtailment of load during periods of peak demand. Unfortunately, this would not be a practical solution because these facilities operate on a restricted seasonal basis which is entirely driven by the relevant fisheries openings, and the highly perishable nature of the food that they process would likely make even planned shutdowns impractical.

No more consideration is given to this strategy.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

A.3.2 Energy Efficiency

While the opportunity for DR programs for the southern communities is limited, there is more promise in exploring simple energy offset to reduce reliance on diesel generation. Implementing energy conservation and energy efficiency measures can be an effective way to reduce electricity demand and, for a diesel generating system, greenhouse gas emission. NLH has pursued energy efficiency programs in Southern Labrador since 2012. These programs have included lighting replacements as well as other "efficiency" programs. As a result, most of the traditional energy efficiency programs have already been implemented in these communities.

A concern in Southern Labrador is the conversion from Diesel or wood heating to electric heat. Even at current heating oil prices (exceeding $1.75 per liter delivered[39]), it is currently less expensive for a resident to heat a home in Southern Labrador using resistive electric heat than it does using heating oil, largely because electrical prices are effectively subsidized by customers on NLH's Island Interconnected System. Assuming that a fuel oil heating system is 80% efficient (typical for a mid-efficiency system), then the amount of energy released from burning 1 liter of fuel oil[40] is approximately the same as using 8.5 kWh of electricity in a resistive heater. Assuming the average annual load is within the first tariff block (1.2D third block)[41], the maximum residential rate in Southern Labrador is $0.18721 / KWH (not including HST), the cost of electricity to replace an equivalent heating value of a liter of heating oil is slightly over $1.60 per Litre. The conclusion is that there is a financial incentive to heat using electricity rather than fuel oil. Notably the Northern Strategic Plan provides reduced power rates, which can further incentivize switching to electric heating systems.

From NLH's perspective, heating with fuel oil costs less and results in lower GHG emissions (see below) than heating with electricity in Southern Labrador.

This is the paradox that NLH finds itself in to provide its service to customers in the Southern Labrador communities.

Since all the Southern Labrador communities have significant winter energy use, driven by heating Loads, a significant opportunity for DSM would be to focus on heating loads. Consequently, two DSM opportunities for the Southern Labrador communities that have been identified. These are:

---

[39] Assumed equivalent to Northern Peninsula (January 2022): https://www.cbc.ca/news/canada/newfoundland-labrador/nl-furnace-oil-increase-jan-12-2023-1.6712433

[40] Natural Resource Canada, Heating with Oil, Energy of fuel oil is 38.2 MJ per liter, Source: https://www.nrcan.gc.ca/sites/nrcan/files/energy/pdf/energystar/Heating-with-Oil_EN.pdf

[41] NLH, Schedule of Rates, Rules and Regulations, Source: https://nlhydro.com/wp-content/uploads/2022/08/2022-07-01_NLH_Schedule-of-Rates-Rules-and-Regulations-July-1-Rural.pdf

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

1. improving the efficiency of existing electrical heating systems; and
2. forestalling future customers conversion from fuel oil heating to electrical heating systems[42].

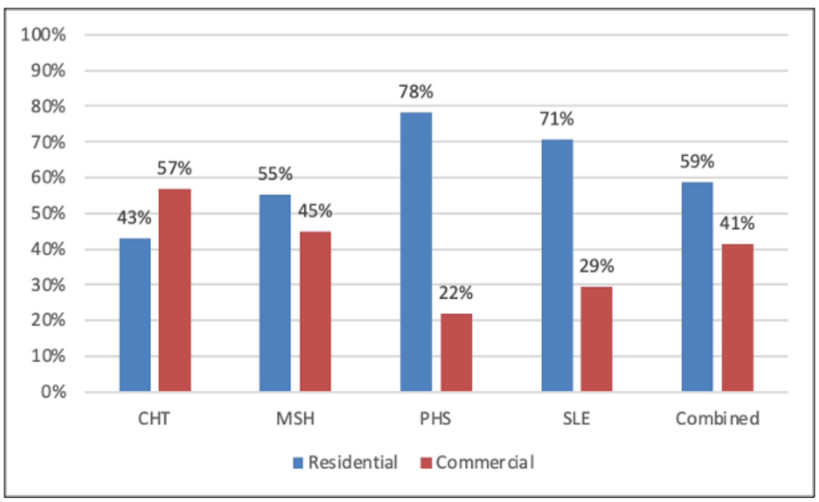
In order to illustrate the benefits of these two opportunities, two cases have been analyzed.

1. The first case explores a per household benefit (both economic and GHG emission) of switching from resistive heating to a heat pump in Port Hope Simpson.
2. The second case demonstrates the value of forestalling switching from heating oil to electricity by modelling a notional conversion of 50% of assumed electric resistive-based heating to fuel oil-based heating.

A.3.2.1 Background Information and Analysis

High-level information on the load profiles of Southern Labrador communities' customers indicates that the majority of the communities' energy consumption is due to the usage of residential loads. This is shown in Figure A-1.

Figure A-1: Historic Customer Load Profile



The last Conservation and Demand Management study conducted by NLH determined that "space heating accounts for about 47% of total residential electricity use. Domestic hot water accounts for the second largest percentage, at 13%. These are followed by lighting at 6%..."[43] Use of a more efficient heating system would result in lower costs for the homeowner, as well as lower electrical subsidies for NLH. Currently the most efficient electrical heating technology is heat pumps, which can now be purchased rated to -30°C, and

---

[42] This second opportunity does not address existing electrical load. However, inasmuch as the existing residential tariff structure creates a strong economic incentive to use higher cost, GHG intense electrical generation, the postponement of fuel switching to electricity will have medium and long term planning benefits. The concept of fuel switching for heating away from electricity seems to be counter-intuitive but actually makes sense from both an economic and greenhouse gas (GHG) emissions perspective when full life-cycle fuel-to-heat efficiencies are taken into account.

[43] Newfoundland Conservation and Demand Management Potential Study: 2015 – Residential Sector Final Report, Page v

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

the technology can also be used for hot water heating. At temperatures below the rated temperature, most systems are configured to switch to a resistive heating mode.

Heat pumps operate by "moving" heat around rather than "making" heat directly from electricity. A refrigerator is a common example of a heat pump – it does not "make" cold directly, rather it moves heat from the inside of the refrigerator to the outside so that the inside is cooler than the outside. This heat is moved to the radiative coils at the back of the refrigerator, which become warmer. In general, a heat pump system is roughly twice as efficient as electric resistive heat[44].

Notably the Isolated Communities Energy Efficiency Program demonstrated roughly a 16% efficiency improvement installing heat pump systems which were used for home heating only, while this appendix assumes that a heat pump can also be used for water heating. The average load for residences using electric heating in this program was 15,000 kWh, so the amount of energy saved per household is likely to be significantly higher than is presented below.

A.3.2.2 Assumptions[45]

The simplified analysis makes the following assumptions:

1. Annual average Port Hope Simpson residential energy consumption is 9,650 kWh.
2. Port Hope Simpson has 238 domestic customers.
3. Based on the above-mentioned load and use profiles, it is assumed that 60% of electrical energy consumption is for heating.
4. Port Hope Simpson diesel generation fuel use is approximately 3.5 kWh / Liter of diesel.
5. Heating oil equivalency is 8.49 kWh per L.
6. NLH's marginal cost of diesel generation is assumed to be approximately $650 / kWh[46].

A.3.2.3 Case 1: Electric Resistance Heating to Electric Heat Pump Heating

The economic benefit of switching from resistive heating to heat pumps is determined by a discounted cash flow methodology. The present-day cost (both as assumed subsidy provided by NLH, and a customer's willing spend) is compared to a series of either 10 or 15 years of future savings. Cash flows are discounted at 3.65% and expressed in real (uninflated) 2023 dollars.

If NLH receives revenues of $187 per MWh and expends $650 per MWh, this represents a direct loss of $463 per MWh. The average per household annual load in Port Hope Simpson is 9,650 kWh. If 60 % of this energy use is heating, and there is a potential offset of 50% by switching to a heat pump, then this represents a

[44] U.S. Energy Department, Electric Resistance Heating, Source: https://www.energy.gov/energysaver/electric-resistance-heating

[45] Data for assumptions provided by NLH unless otherwise referenced.

[46] Note: Based on results of the IRP presented Section 7.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

potential annual energy savings of 2,900 kWh per household. This reduced energy demand represents a potential annual saving (per house) of approximately $540.

The present value of this saving for 10 or 15 years (at 3.68%) is summarized in Table A-1.

Table A-1: Potential NLH Saving from Heating Energy Offset

	10-years Heat Pump Life	15-years Heat Pump Life
Per House Annual NLH Savings	$1,340	$1,340
PV Per House	$11,000	$15,200

The savings that NLH can achieve by offsetting generation are not the only economic benefits that can be achieved by a switch to heat pump-based heating. Individual customers would also save on their electricity bills.

The individual household saves 3,860 kWh annually, based on a tariff of $0.18721; this represents annual savings of $540. Similar to the analysis above, this is discounted at 5.68% over 10 to 15 years, as shown in Table A-2.

Table A-2: Potential Household Saving from Heating Energy Offset

	10-years Heat Pump Life	15-years Heat Pump Life
Per House Annual Savings	$540	$540
PV Per House	$4,500	$6,200

This analysis suggested a combined economic benefit to NLH and its local customers of between $15,500 and $21,400 per household for the installation of a heat pump to offset heating energy use. Note that the Northern Strategic Plan and changes in rate structure will increase the cost to NLH and reduce the cost to the ratepayer, but the combined cost would remain the (subsidized) marginal cost of generation to produce the energy for electrical heat.

Apart from the economic benefit, the reduction of energy use would have a direct benefit in the reduction of GHG emissions derived from diesel generation.

Table A-3 summarizes this benefit.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Table A-3: Case 1 – Annual Per Household GHG Offset

Port Hope Simpson	Energy Savings (kWh)	Diesel Fuel Offset (L)	GHG Reduction (Tonne of CO_2)[47]
Total	689,000	198,000	528
Per household	2,900	830	2.2

A.3.2.4 Case 2: Comparison of Electric Resistance and Fuel Oil Diesel Heating

As discussed above, it is currently less expensive to heat using electrical resistive heat than to heat with fuel oil. This incentive encourages existing heating oil users to consider switching to electricity to heat.

Current data showing the communities total energy use was unavailable. Therefore, in order to demonstrate the potential economic and GHG difference between electrical heating and fuel oil use, an analysis of the average annual electrical energy demand used for heating for Port Hope Simpson was used as a proxy. Port Hope Simpson was selected because it has the highest residential to commercial load ratio among the six communities.

Table A-4 shows the determination of per capita energy use for heating.

Table A-4: Case 2: Per Capital Heating Energy Analysis

Community	Assumed Average Annual Heating Demand (MWh)	Assumed Number of Customers	Per Capita Annual Heating Energy Use (kWh)
Port Hope Simpson	1,378	238	5,800

This heating load is then converted to equivalent diesel use and equivalent furnace oil use. For this conversion, it has been assumed that the Port Hope Simpson diesel generators produce 3.48 kWh per Liter. No allowance for station usage/losses has been made. Similarly, an energy conversion of 8.49 kWh of heat per Liter has been assumed for thermal furnace heating efficiency. With assumed costs of $1.75 per Liter for residential heating oil the embedded energy cost is shown in Table A-5.

Table A-5: Port Hope Simpson Per Household Fuel Difference Between Electricity and Furnace Oil

Community	Generator Diesel Use	Fuel Oil Required (L)	Difference
Port Hope Simpson	1,660 L	680 L	980 L

[47] Assuming 2.665 kg CO_2/L for diesel

MIDGARD CONSULTING
Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Finally, assuming an equivalent GHG release of 2.665 kg / L, this fuel use is converted to an annual per capita GHG release.

This analysis is shown in Table A-6.

Table A-6: Comparison Fuel Use for Heating Load

Community	Assumed Average Annual Heating Demand (kWh)	Generator Diesel Use (L)	Annual GHGs from Generators ($Kg\ CO_2$)	Equivalent Fuel Oil Required (L)	Annual GHGs from Fuel Oil ($Kg\ CO_2$)	GHG Reduction using Fuel Oil ($Kg\ CO_2$)
Port Hope Simpson	5,800	1,660 L	4,400	680	1,800	2,600

The above analysis suggests that contrary to expectations, the greenhouse gas emissions of fuel oil heating is significantly lower than using electric heating. Using a high efficiency heat pump rather than resistive heating will still emit more CO2 than heating with fuel oil, although this will reduce the difference to only 400 kg/year per household.

A.3.3 DSM Summary

Pursuit of industrial DR for the Southern Labrador communities is likely ineffective because the main industries are seasonal, and the resources (codfish, shrimp, and crab) require expedient processing to avoid spoilage. Residential or distributed DR is unlikely to be effective based on previous attempts at similar programs. The structure of the existing peaks (summer for Mary's Harbour and Charlottetown, winter for the other communities) means that interconnecting these communities can provide many of the benefits of DR, which has been investigated in detail in the main body of the IRP.

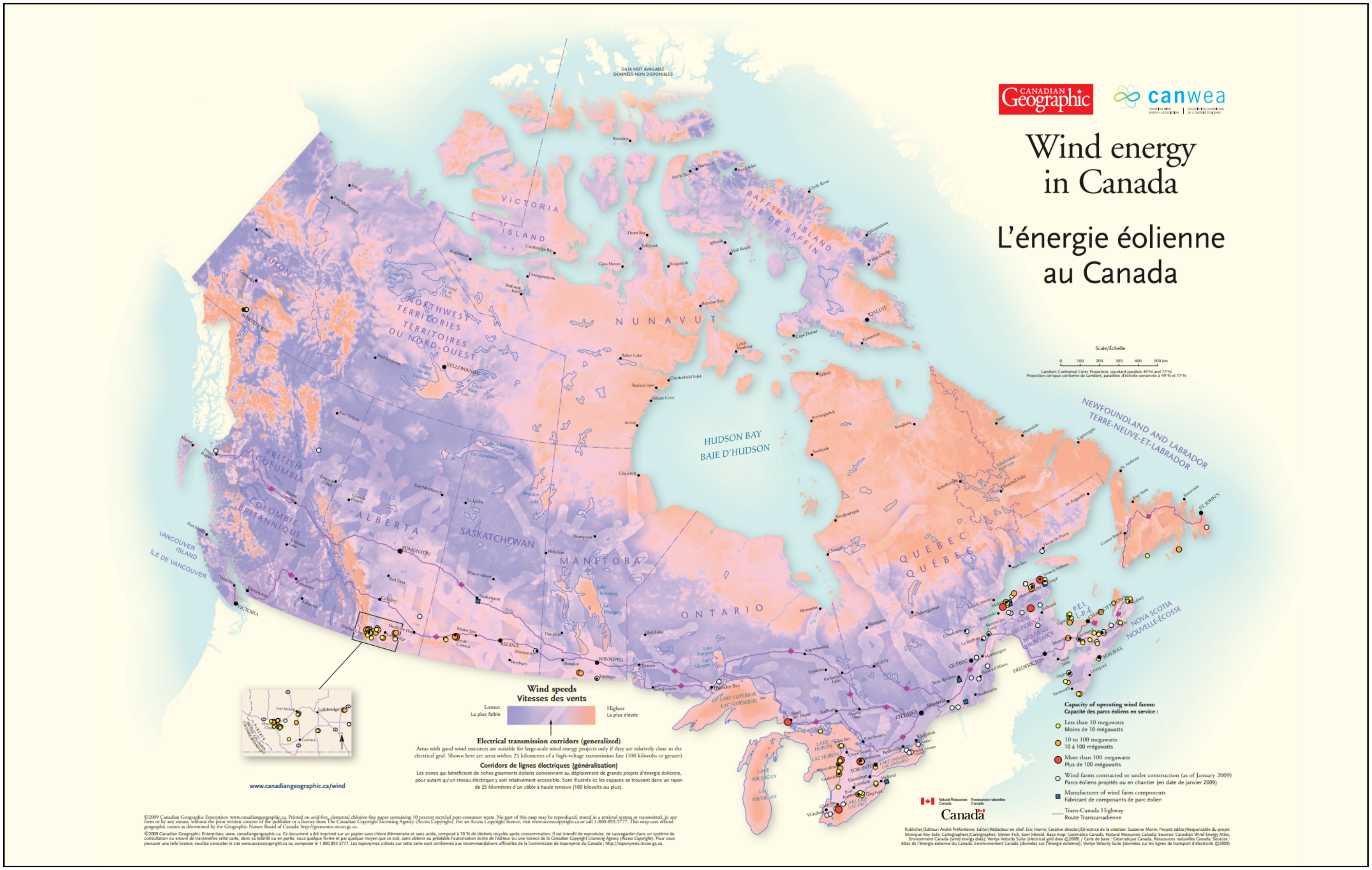
There is a potential opportunity for energy efficiency by providing financial incentives for existing customers who heat by resistive radiant devices to switch to more efficient heat pumps. However, customers that currently heat by furnace oil should not be further incented to switch to electric heating. A more detailed and comprehensive study is recommended to determine the actual magnitude of efficiencies that can be realized.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

APPENDIX B: WIND ENERGY POTENTIAL IN CANADA



Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Attachment 2

Review of Potential Impacts on IRP of 2023 Federal Budget

Midgard Consulting Inc.

March 30, 2023

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

MEMORANDUM

To: Newfoundland Labrador Hydro ("NLH")

From: Midgard Consulting Inc.

Date: March 30, 2023

Subject: Review of Potential Impacts on IRP of 2023 Federal Budget

---

1 Introduction

Midgard Consulting Inc. ("Midgard") prepared an Integrated Resource Plan ("IRP") on behalf of Newfoundland and Labrador Hydro ("NLH") for the southern Labrador communities of Charlottetown, Lodge Bay, Mary's Harbour, Pinsent's Arm, Port Hope Simpson, and St. Lewis. The IRP was submitted on March 28, 2023.

That IRP concluded that the immediate construction of a 25 kV interconnected system and regional diesel plant is the most cost-effective solution to provide Firm capacity to these six communities. It further concluded that diesel use could be materially offset through the integration of wind and or solar renewable energy onto the system, procured with Power Purchase Agreements ("PPA"s) from third parties which are likely to include Indigenous ownership and participation.

Also on March 28, 2023, the Federal Government of Canada released its 2023-24 budget, titled, "A Made-In-Canada Plan: Strong Middle Class, Affordable Economy, Healthy Future" ("the Budget"). A significant focus of the Budget is federal investment and support of electrification of Canada's economy from non-emitting generation.

Midgard anticipated ongoing Federal financial support for electrification from renewable energy sources. However, based on high-level observations from the Budget highlights, nothing contained within the Budget alters the IRP's conclusions.

This memo provides further detail and rationale for that conclusion.

2 Relevant Budget Items

Contained within the Budget are several not unexpected items to provide continued Federal financial support for renewable electricity and zero emission technologies. These are contained within Chapter 3 of the Budget – "A Made-In-Canada Plan: Affordable Energy, Good Jobs, and a Growing Clean Economy".

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

Priorities identified in Chapter 3 are:

1. Electrification
2. Clean Energy
3. Clean Manufacturing
4. Emissions Reduction
5. Critical Minerals
6. Infrastructure
7. Electric Vehicles & Batteries; and
8. Major Projects.

Specific provisions that directly relate to the analysis carried out in Midgard's IRP are discussed below.

2.1 Clean Electricity Investment Tax Credit ("ITC")

This is a 15% refundable tax credit on investments in clean generation and interprovincial transmission projects – regardless of the taxation status of the investor. This means that non-tax paying entities, such as Crown corporations and publicly owned utilities, corporations owned by Indigenous communities, and pension funds, would be eligible.

Technologies to be supported by this ITC are:

- *"Non-emitting electricity generation systems: wind, concentrated solar, solar photovoltaic, hydro (including large-scale), wave, tidal, nuclear (including large-scale and small modular reactors);*
- *Abated natural gas-fired electricity generation (which would be subject to an emissions intensity threshold compatible with a net-zero grid by 2035);*
- *Stationary electricity storage systems that do not use fossil fuels in operation, such as batteries, pumped hydroelectric storage, and compressed air storage; and,*
- *Equipment for the transmission of electricity between provinces and territories."*

The ITC is available through 2034.

The IRP concluded that diesel generation is by far the most economic source of capacity for the isolated systems of southern Labrador. A 15% ITC will not overcome the significant cost increment for non-emitting sources of capacity. It remains Midgard's conclusion that a diesel-based backbone system is needed to provide reliable capacity.

That said, the ITC is expected to enhance the cost competitiveness of renewable generation energies. It is Midgard's opinion that diesel displacement from renewable sources is important in the resource mix. Economic analysis confirms that a renewable augmented system would be lower cost than a pure diesel-based generation. This ITC further strengthens that conclusion. The broad eligibility for this ITC does not favour one provider over another and so it remains Midgard's opinion the NLH would be best to procure renewable energy from independent producers.

MIDGARD CONSULTING

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com

828 – 1130 West Pender St.
Vancouver BC, Canada
V6E 4A4

2.2 Further capitalization of the Canada Infrastructure Bank

Direct investment through the Canada Infrastructure Bank ("CIB") is intended to support its Clean Power priority and its Green Infrastructure Priority. The budget provides for *"low-cost and abundant financing through a targeted focus on clean electricity from the Canada Infrastructure Bank".*

This funding, while targeted at both large scale and small scale projects is again expected to further enhance NLH's ability to secure lower cost renewable energy to offset diesel fuel use while maintaining its diesel generating station to provide firm capacity as needed.

Smaller scale Indigenous renewable projects, as currently supported the CIB's Indigenous Community Infrastructure Initiative can further bolster Midgard's conclusion that a diesel capacity system offset with renewable energy resources remains the least cost reliable solution for NLH for the southern Labrador Communities.

3 Conclusions

Midgard has reviewed summary highlights of the Budget commitments and concluded that none of the financial supports therein alter the conclusions of the IRP.