Market Opportunities for Offshore Wind in Atlantic Canada

June 2025 Report

Stantec
Energy+Environmental Economics

Phase One Results

Atlantic Canada Offshore Wind Grid Integration and Transmission Study

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ACKNOWLEDGEMENTS

The Atlantic Canada Offshore Wind Grid Integration and Transmission Study is a research project developed and led by Net Zero Atlantic. The research is conducted by Stantec in partnership with Energy and Environmental Economics (E3). The project is supported by funding from Natural Resource Canada's Office of Energy Research and Development through the Energy Innovation Program.

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Letter from Net Zero Atlantic

Net Zero Atlantic is pleased to share with research colleagues and vested interests the findings from Phase 1 of a two-year study, the Atlantic Canada Offshore Wind Grid Integration and Transmission Study.

In 2023, we undertook the work of scoping a research project that would advance our understanding of how to make offshore wind a reality for our region. This report on domestic and international market opportunities is the first published deliverable. Along with a policy assessment report to be released with this study, it will serve to inform our work in Phase 2 by providing current context and future possibilities in the region.

We would like to thank our project funder - Natural Resources Canada's Office of Energy Research and Development (OERD) Energy Innovation Program (EIP). This program focuses on advancing clean energy technologies to both support Canada's climate change targets, as well as to support the transition to a low-carbon economy.

To conduct the work, we needed an experienced team with in-depth knowledge of our region. We would like to thank consultants Stantec and Energy and Environmental Economics (E3) for helping us undertake this important work and providing us with this thorough report.

We would also like to acknowledge the participation of provincial government and electrical utility representatives who are involved in project management and technical committees for the study and have provided key insights and guidance throughout this phase of work.

Next Phases: Phase 2 – Offshore Wind Resource Potential Study and Phase 3 – Grid Integration Study are next, and the results in this report will be further iterated upon throughout the remainder of the project. We are excited to continue to share these results throughout the next year.

If you have questions about the study, we invite you to visit NZA's website, which has a page dedicated to updates on this important piece of work.

Thank you for reading.

Kiera Walsh, Project Manager
Sven Scholtysik, Research Director
Net Zero Atlantic

Authors & Acknowledgements

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. E3's analysis is utilized by the utilities, regulators, developers, and advocates that are writing the script for the emerging clean energy transition in leading jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

Phase 1 E3 Study Team: Liz Mettetal, Nathan Grady, Pedro de Vasconcellos Oporto, Ben Joseph, Chen Zhang, Riti Bhandarkar, Madeline Macmillan, Lakshmi Alagappan, and Arne Olson.

Acknowledgements

This report was developed by the E3 team as part of the Phase 1 deliverables for the Offshore Wind and Transmission Study. This report is prepared for Net Zero Atlantic and sponsored by Natural Resources Canada. Net Zero Atlantic provided guidance, research insights and feedback throughout the report process. This report is part of a broader study, in which E3 is a subcontractor to Stantec Consulting Ltd (Stantec). E3 also benefited from feedback and collaboration with Stantec in preparation of these deliverables.

This report benefited from the advice and feedback of the Project Management Committee (PMC) and a Technical Committee (TC), as listed on the NZA project website. Participation in either group does not imply endorsement of any of the report's conclusions.

This report represents findings and analysis from the first phase of a multi-year study. Future phases will build on this analysis by incorporating updated inputs and assumptions to reflect evolving policy and electric sector grid conditions, and by expanding the analysis to assess operational needs and constraints in greater detail. Input data – including contracted resources, capital cost estimates, offshore wind operating characteristics, load forecasts, inter-provincial transfer capacity, and other key inputs – are based on the best available sources as of October 2024. Similarly, modeled policy assumptions and impacts reflect the status quo as of October 2024. Any policy changes, including those resulting from recent elections, as well as updates to procurements, cost data, and other key inputs, will be integrated into the subsequent phases. Notably, Phase 2 is developing a more detailed, site-specific offshore wind characterization, which will be reflected in the final modeling. This study will conclude with a Final Roadmap detailing the methodology and findings from each analytical phase, including incorporating updates to the offshore wind characterization as well as key changes in policy, technology and costs that have occurred since the Phase 1 modeling was completed.

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Acronym Definitions & Notes

Acronym	Definition
ELCC	Effective Load Carrying Capability
GW	Gigawatt (1000 megawatts)
H2	Hydrogen
HQ	Hydro Québec
IRP	Integrated Resource Plan
ISO-NE	Independent System Operator for New England
LCOE	Levelized Cost of Energy
LIL	Labrador Island Link
NB	New Brunswick
NBP	New Brunswick Power
NL	Newfoundland & Labrador
NPV	Net Present Value
NS	Nova Scotia
NSPI	Nova Scotia Power Inc.
OBPS	Output-Based Pricing System
OSW	Offshore wind
PEI	Prince Edward Island
PLEXOS LT	PLEXOS Long Term
PRM	Planning Reserve Margin
RA	Resource Adequacy
SMR	Small Modular Reactors
Tx	Transmission
UCAP	Unforced Capacity

All dollar values reported in this study are in Canadian nominal dollars.

Executive Summary

Federal regulations commit Canada to reducing greenhouse gas emissions by 40–45% below 2005 levels by 2030 and achieving net-zero emissions by mid-century. Meeting these goals will require a fundamental transformation in how energy is produced and consumed across the country. In the Atlantic Provinces, the power sector accounts for roughly one-quarter of total emissions, with fossil fuels still supplying about 15% of electricity generation today. However, near-term emissions targets and the continued buildout of renewables in the region are expected to drive substantial reductions by 2030. Beyond 2030, offshore wind presents a significant opportunity to further decarbonize the power sector—supporting progress toward net-zero emissions while also meeting rising electricity demand from the electrification of buildings, transportation, and industry.

Offshore wind power generation has many advantages: strong and stable output, proximity to demand, high technical potential relative to land-based resources, and zero carbon emissions. The extensive coastline of the Atlantic Provinces also boasts some of the highest performing offshore wind resources along the North American Eastern Seaboard, with particularly high output in the winter, the time when clean energy is needed most. Early investments in offshore wind provide an opportunity to create an offshore wind industry and jobs, leveraging the region's strong marine-oriented labor force and research expertise. This clean resource may also serve nascent industries like green hydrogen, building on plans to support European markets or domestic demands. While these opportunities hold promise, realizing offshore wind's potential will require a coordinated effort to address key challenges, including lowering the cost of offshore wind and building out the transmission infrastructure to transport clean electricity to sources of demand.

This document outlines the **market opportunity for offshore wind** and serves as the Phase 1 deliverable within the *Atlantic Canada Offshore Wind Grid Integration and Transmission Study*, facilitated and managed by Net Zero Atlantic and funded by Natural Resources Canada. As described in the report, the full study will build out a comprehensive assessment of the potential for a transformative GW-scale offshore wind industry in the Atlantic Provinces, with a long-term view from 2035-2050. The Phase 1 deliverable focuses on the potential market and offtake opportunities for offshore wind, and models future scenarios in which offshore wind helps decarbonize domestic electricity consumption, export clean energy to neighboring markets, and serve growing hydrogen demand.

The approach in Phase 1 evaluates long-term electricity demands and opportunities using an industry-leading electricity system capacity expansion model, PLEXOS-LT. This ensures that scenario-based offshore wind planning targets are considered as part of the overall regional electricity system, simulating how offshore wind interacts with the rest of the existing and potential future resources on the grid. The model performs a least-cost optimization to meet remaining demand with existing and potential future supply, including offshore wind targets. It integrates robust representation of candidate resources, and key operational, policy, transmission and other system constraints. This enables the evaluation of offshore wind targets and their impact on energy system costs, reliability, and emissions. In Phase 2, the study will perform more detailed hourly simulations of the future electric grid, evaluating operational implications and integration investments. The findings from Phase 2 will be used to refine the portfolios and targets for the Final Roadmap.

The electric system-level modeling and market analysis generated the following key findings:

1. **Offshore wind resources can meet significant regional electricity demand in Atlantic Canada, serving growing load and reducing fossil fuel dependence, including during winter periods in which demand is highest in the Atlantic Provinces.** Regional electricity demand may grow nearly 30% between 2025 and 2050, based on utility estimates of electrification. Policy drivers are also changing the grid, with output-based carbon pricing and mandates for about 1.8 GW of coal retirements by 2030. High-quality offshore wind (OSW) resources may critically support this transition in the mid to late 2030s and beyond, with the highest output during winter months of December to March when growing loads will continue to stress the system. Although many onshore wind projects are already planned and under construction, utilizing even a small portion of the offshore wind technical potential could play an important role in meeting growing energy demand and replacing retiring fossil fuel generation. This study modeled scenarios illustrating the potential for 1 GW of offshore wind to support domestic needs by 2035, growing to 2.5 GW by 2040. By 2040, scenarios illustrated that offshore wind could support about 25% of regional electricity demand (11.6 TWh). Additional hourly dispatch analysis in Phase 2 will further characterize potential for reductions in fossil fuel dispatch, based on hourly dispatch of the system over a range of conditions. This future, in which offshore wind supports regional needs, is shown in the middle column of Figure ES-1.

2. **Given decarbonization targets across the Northeast U.S. and Canada, Atlantic Canada's high performing offshore wind resources may serve GW-scale clean energy demands in New England and central Canada.** Like Canada, most New England states have economy-wide decarbonization targets aligned with net-zero, requiring a substantial reduction in fossil fuel reliance—currently accounting for about 50% of electricity generation—and significant electrification of transportation and buildings. Many New England planning scenarios project a need for at least 100 GW of clean electricity generation capacity, including over 30 GW of offshore wind by 2050[1]. Offshore wind from Atlantic Canada can contribute to this need, given its high capacity factor and close proximity to New England. Other markets, such as Québec and Ontario, could also benefit from the diversity offshore wind provides. However, large-scale exports will require significant new transmission to these other regions of Canada or across the US border; coordinating transmission investments at scale across regions will be challenging but is critical to realizing this opportunity. This study explored scenarios that support 2 GW of offshore wind export capacity by 2035, 4.5 GW by 2040, and 6 GW by 2050. While export opportunities involve greater investment, coordination, and cost, they could deliver valuable regional benefits. Phase 1 demonstrates that the potential exists; Phase 2 and 3 will further characterize associated costs, benefits and transmission needs.

3. **Offshore wind has the potential to help grow the nascent green hydrogen industry in the Atlantic provinces, representing a significant, albeit still emerging and therefore uncertain, market opportunity.** Green hydrogen—produced using renewable electricity to split water into hydrogen

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[1] For examples, see ISO-NE's 2050 Transmission Planning Study: 2024_02_14_pac_2050_transmission_study_final.pdf and Massachusetts 2050 Clean Energy and Climate Plan (CECP): Clean Energy and Climate Plan for 2050

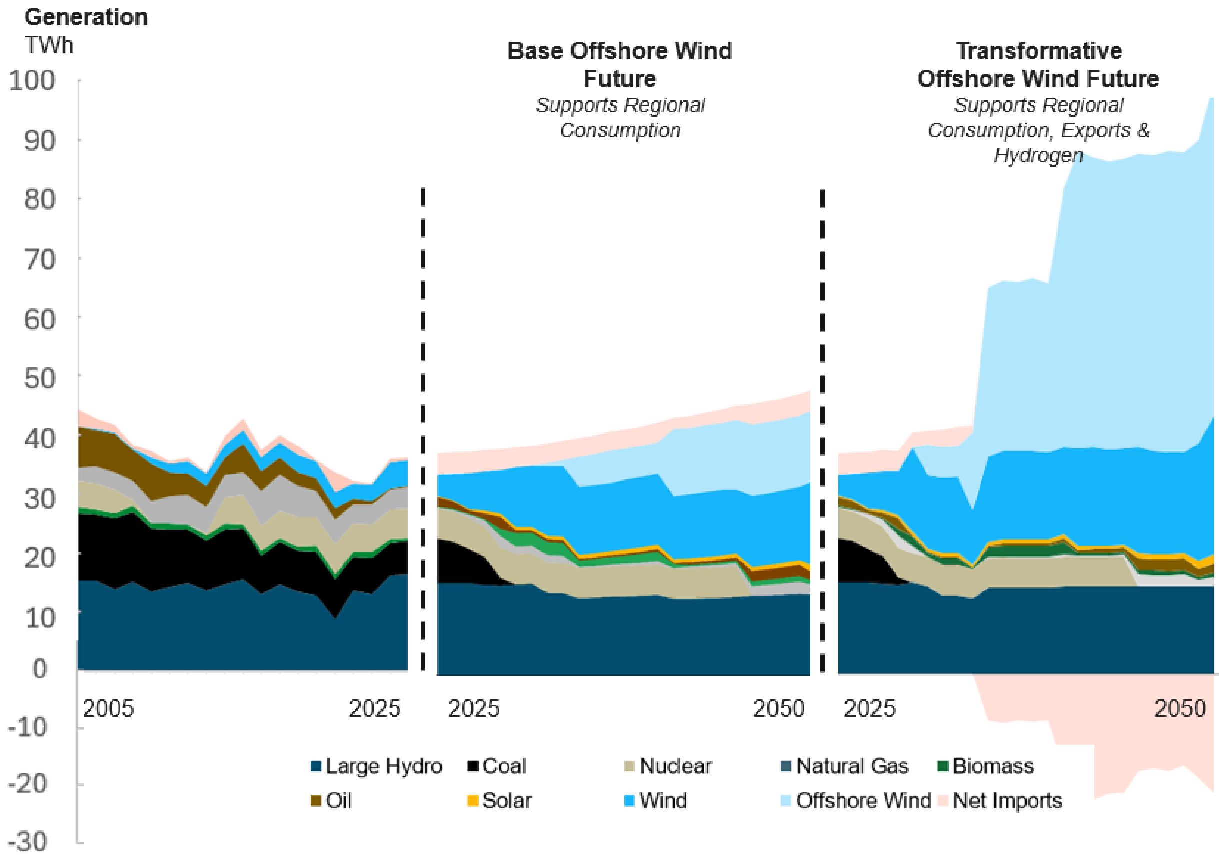
and oxygen—is gaining global traction as a potential solution for decarbonizing hard-to-abate sectors like heavy industry, long-haul transport, aviation, and shipping, as well as for supporting electricity demand during periods of high load and low renewable output. The market, trading systems, and supply chains to support green hydrogen are in their infancy, but efforts are underway to accelerate development in Canada and other global markets, with government and private sector support. To this end, Canada and Germany signed a hydrogen alliance in 2022, and in 2024, Canada committed up to $300 million to support hydrogen trade.[2] Newfoundland and Labrador are also building international connections, having signed agreements with key European ports to advance hydrogen supply chains. These initiatives demonstrate encouraging momentum, even as current production costs for green hydrogen globally and in Atlantic Provinces remain significantly higher than fossil-based alternatives. To support both domestic and export hydrogen demands, hydrogen will need to be cost competitive with other clean options and production demands; thus, cost reductions in electrolyzers as well as offshore wind power generation will be necessary.

Given that green hydrogen represents the largest but a less predictable market opportunity, this study evaluated a range of hydrogen electrolyzer demand levels, from about 15 to 40 TWh in 2035, rising to 30 to 70+ TWh by 2050 to support green hydrogen production, all reflective of hydrogen as a long-term regional decarbonization strategy. This level of investment in hydrogen production could support up to 1.4 million tonnes of green hydrogen per year by 2050, enabled by a combination of onshore and offshore wind, with offshore wind playing a growing role over time. Specifically, scenarios modeled offshore wind builds to support hydrogen ranging from 2 to 4.5 GW in 2035, to 4 to 8 GW by 2050.

A future in which offshore wind supports regional needs, export markets, and significant hydrogen production is shown on the far right below, illustrating the dramatic transformation this would imply for the region.

[2] https://www.canada.ca/en/natural-resources-canada/news/2022/08/canada-and-germany-sign-agreement-to-enhance-german-energy-security-with-clean-canadian-hydrogen.html
Government of Canada Announces $300 Million in Port Hawkesbury on Canada - Germany Hydrogen Alliance - Canada.ca

Figure ES-1. Electric Grid in Atlantic Provinces Has Begun Significant Transformation, And Will Change Dramatically in the Next Decade



Notes: The left column reflects historical regional data from Canada's Energy Future, 2023. The middle figure shows the "Domestic-only" scenario, which includes supporting offshore wind primarily for use in the Atlantic provinces. The right column shows the "All Markets" scenario, which includes supporting domestic consumption, export markets and hydrogen demand. Note that the model added transmission/export capability and hydrogen demand at five-year increments, contributing to "jumps" in demand in the third column/scenario. The model also curtails excess energy (not shown in graph) contributing to variation in output as some onshore and offshore wind are curtailed when their output exceeds total demand.

4. **Building an offshore wind industry requires substantial investment to reduce project costs, which today have capital costs roughly double land-based wind projects; these higher costs would lead to increases in electricity rates.** While offshore wind benefits from higher energy output due to the use of larger turbines and often more consistent wind patterns, these larger turbines contribute to higher up-front capital costs, which will put upward pressure on electric rates. Additionally, constructing wind farms in marine environments, whether fixed to undersea foundations or floating on platforms, necessitates complex infrastructure to withstand harsh marine conditions. Transmission is similarly more expensive offshore than on land. Atlantic Canada, with its well-developed ports and marine-oriented industries, labor force, and research organizations, has the potential to contribute to the learning-by-doing required to lower the cost of offshore wind. That said, the offshore wind industry's nascency in North America still creates longer project timelines

and risks, given that unlike Europe, less than 400 MW of offshore wind is operational in North America today, though several GW are planned or under construction. This, as well as greater uncertainty related to weather and operational risks, translates to higher costs. Finally, offshore wind costs and capabilities must compete with clean energy alternatives, including onshore wind, new hydro and small modular reactors. As discussed in the report body, these technologies may provide complementary features to support load growth and the gaps left by retiring coal but will compete for capital to meet limited offtake opportunities.

5. **To maximize regional benefits of large-scale offshore wind development, coordinated transmission investment will be essential for ensuring efficient power delivery to load, both within the Atlantic Provinces and to neighboring regions.** Current interties between the provinces in Atlantic Canada are small and often fully utilized during times of need; this constrains the amount of generation that can be shared among provinces. Scenarios that model modest build-out of offshore wind (about 2.5 GW) maintain curtailment levels aligned with the Reference case (about 3 TWh). However, curtailment grows significantly after 2035 as higher offshore wind levels with similar generation patterns are integrated to support hydrogen and exports. For example, in scenarios that build 13 GW offshore wind with 500 MW of additional transmission from Nova Scotia to New Brunswick and 6+ GW of new transmission to New England, almost 15 TWh of curtailment remains. High curtailment potential increases risk, which could put further upward pressure on costs as developers work to mitigate that risk in their offtake contracts. Exploring the relationship between offshore wind curtailment and export capacity will be a key focus in Phase 2, which performs extensive operational modeling to identify approaches to most cost-effectively integrate offshore wind in order to minimize curtailment. Future phases of work will also use more detailed offshore wind generation profiles, which will capture more geographic diversity within sites in the region, and identify opportunities to reduce the coincident peak generation periods which drive significant curtailment challenges.

Phase 1 estimates the potential size and timing of key offshore wind offtake opportunities to inform the range of realistic targets for study in Phase 2 and 3. While Phase 1 relies on utility and research-based offshore wind assumptions, the subsequent phases will fully characterize the offshore wind potential and output profile using "on the ground" data, assess the integration requirements, and model the implications for system operations. This market opportunity assessment will also be refined based on the more granular characterization of offshore wind—including integration needs and costs—that is developed as part of Phases 2 and 3.

Introduction

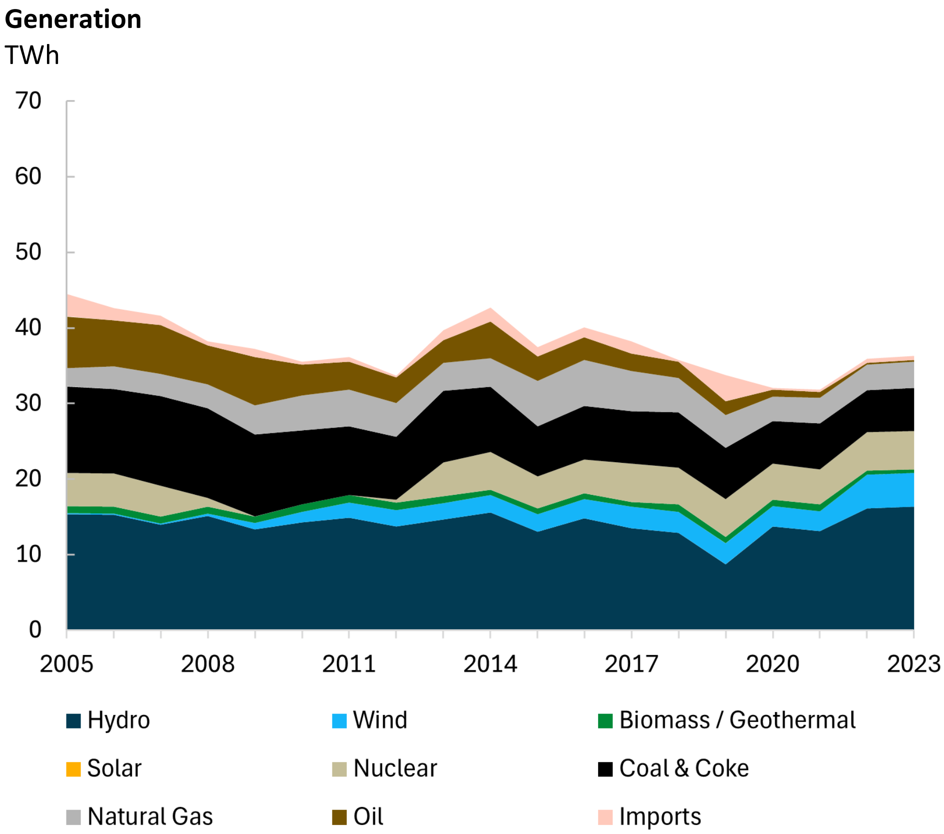
Study Context

Recognizing the risks of climate change, Canada has committed to 40-45% emissions reductions by 2030 and net-zero by 2050. This will require near-complete decarbonization of key energy sectors of the economy, including power, transportation, buildings and industry. To achieve these targets, the region is pursuing a range of policies and actions to accelerate decarbonization, including for example carbon pricing and clean electricity regulations.[3]

The region has already made significant progress toward decarbonizing its economy, including its power sector. As shown in Figure 1 below, the region, particularly Newfoundland and Labrador, benefits from abundant hydro generation to serve load. The next largest generation sources in 2005 were coal and oil, though fossil generation has fallen in half over the last 15 years, and coal generation will be entirely phased out by 2030. This generation mix has been complemented by small but rapidly expanding onshore wind capacity, which is expected to hit at least 15 TWh region wide by 2030. The challenge in 2030 and beyond will be to replace remaining fossil generation to the extent feasible, while serving growing electrification loads and other potential new loads such as for hydrogen production.

[3] This is outlined in more detail in this study's policy short report.

Figure 1. Historical Electricity Generation Across the Atlantic Provinces [4]



To support these needs, offshore wind has the potential to be a cornerstone of regional decarbonization for the Atlantic Provinces and its neighbors, directly and indirectly facilitating sector transformation. As a scalable and abundant resource, offshore wind provides a clean energy source to offset fossil fuel baseload generation in the power sector. This clean electricity can also support electrification of other energy-consuming sectors, such as transportation and buildings, by providing the necessary clean electricity to meet increasing demands. Furthermore, offshore wind can indirectly advance progress toward net-zero by enabling the production of green hydrogen, a versatile energy carrier that can decarbonize hard-to-abate sectors like heavy industry. Unlocking the potential for offshore wind will require investments in lowering its capital-intensive development costs and building the transmission infrastructure needed to bring the clean energy supply on land and to sources of demand.

This report is part of an overall study, *Atlantic Canada Offshore Wind Integration and Transmission Study*, which assesses the potential to integrate GW-scale offshore wind into Atlantic Canada, including a detailed assessment of pathways to market, constraints, and investments needed to support the transition. The study will deliver key outputs, including:

+ Highly resolved **database of wind speed profiles** for potential offshore wind development sites across Atlantic Canada;

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[4] Canada's Energy Future, 2023. Data obtained here: [Macro Indicators - Canada.ca]

- Assessment of **planning and operational challenges and opportunities** associated with developing the Atlantic Canadian offshore wind resource for the electricity grid; and
- Analysis of **grid infrastructure limitations and costs** necessary to allow high penetration of offshore wind electricity.

To support these overall goals, the study proceeds with three phases of modeling and analysis:

- **Phase 1: Path to Market.** This phase identifies domestic, export, and hydrogen production offtake opportunities for offshore wind, leveraging a policy and resource assessment of the region to build out detailed electric sector system modeling. It also identifies feasible offshore wind targets and key enablers of the path to market.
- **Phase 2: Offshore wind Resource Potential Study**. This phase characterizes offshore wind technical, locational, and economic resource potential and actual deployment. It also creates a public database and visual graphic interface for developers, researchers, and government.
- **Phase 3: Grid Integration Study.** This phase focuses on the investment and operational effort necessary to integrate three different levels of offshore wind into the Atlantic Provinces. This phase involves evaluating coordinated transmission solutions for integrating offshore wind. This phase will also synthesize the three phases into a Roadmap and Action Plan and create a final data visualization.

Phase 1 Questions

This Phase 1 report addresses the following key questions:

- **Policy & Resource Assessment:** How has the region been planning for a decarbonized future? What policy representation and resource planning assumptions should be reflected in the modeled scenarios?
- **Domestic Markets:** How can offshore wind support regional load growth, given electrification and planned fossil retirements?
- **Export Markets:** How can offshore wind support export markets, particularly markets with decarbonization targets?
- **Hydrogen Markets:** How can offshore wind at higher levels grow the hydrogen industry to serve regional and potentially international demand?

The sections that follow summarize the modeling framework, the modeling assumptions derived from the resource assessment, the scenario design to evaluate offshore wind market opportunities, the resulting resource portfolios and enabling factors, and the implications for Phase 2.

Modeling Approach and Inputs

The overall goal of the study is to evaluate a range of offshore wind offtake opportunities, assess the potential long-term electric demand associated with each, and construct scenarios with offshore wind targets aligned with those expected demands. These scenarios are assessed using the PLEXOS LT electricity system capacity expansion model. This approach ensures that scenario-based offshore wind planning targets are evaluated within the context of the broader regional electricity system, simulating how offshore wind interacts with both existing and potential future grid resources. The model identifies least-cost pathways to meeting electric demand with offshore wind, alongside other supply sources, while adhering to key system constraints. This supports analysis of offshore wind's impact on system costs, reliability, and emissions. In Phase 2 and 3, the modeling will build on this foundation through more detailed hourly modeling to assess operational roles, investments, and costs.

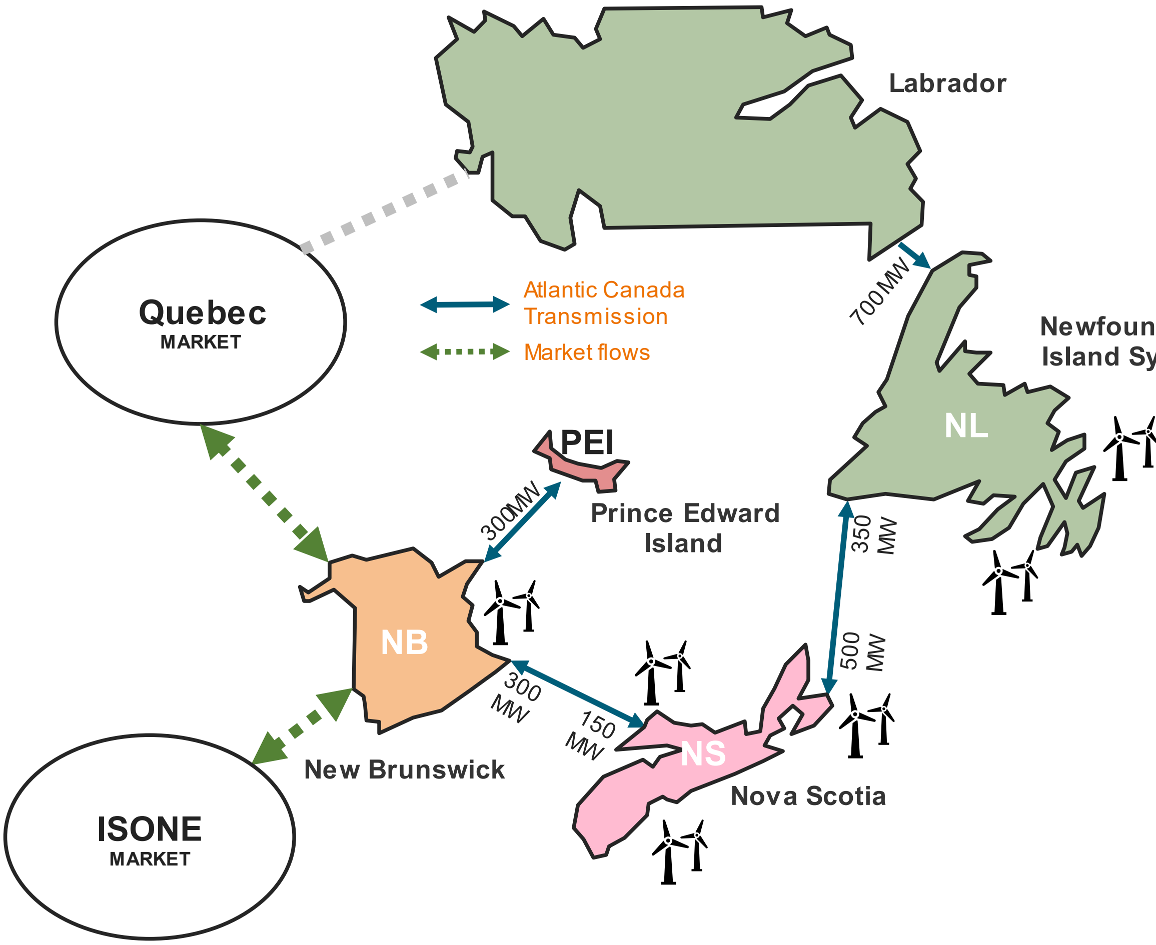
This section provides a brief overview of the modeling toolkit for this phase, key input assumptions, and the modeling scenarios developed for this study.

Modeling Framework

E3 utilized Energy Exemplar's PLEXOS LT model to perform the capacity expansion modeling for this study. PLEXOS LT is an optimization model that identifies least-cost resource portfolios to meet electricity demand, subject to constraints that reflect key operational, policy, transmission, and other system constraints. When developing inputs for this study, E3 leveraged both publicly available data and client-provided data to model the existing system and future expansion resources. The following subsections outline the detailed data and input assumptions. More information about the PLEXOS LT model is available on the Energy Exemplar website (https://www.energyexemplar.com/plexos).

The PLEXOS LT model for this study included four core zones: Nova Scotia, New Brunswick, Prince-Edward Island, and the Island of Newfoundland (part of the Province of Newfoundland & Labrador). The model also included external connections to Québec, New England, and Labrador grids, to ensure sufficient representation of import and export dynamics. This high-level grid topology is illustrated in Figure 2 below. PLEXOS models both least-cost co-optimization of investment in new resources as well as hourly operations of select sample days that reflect a range of representative system conditions.

Figure 2. High-Level Model Load Zones and Transmission Linkages



Note: Loads and resources were modeled for Nova Scotia, New Brunswick, Prince-Edward Island, and the Island of Newfoundland. Québec and ISO-NE reflected as market price strips. Flows from Labrador to the Newfoundland Island System are included, but electricity demand in Labrador was not provided by the utility and thus full load and resource representation of Labrador is not included in this phase (future phases may refine this if data becomes available).

Input Assumptions

The modeling in PLEXOS requires input data and assumptions to characterize the existing system and the evolution of demand, policy constraints, and investment opportunities. E3 gathered data and assumptions based on a range of available public data sources as well as direct support from the utilities where possible, who provided data, guidance on assumptions, and feedback. Assumptions on policy are being monitored and will be updated with each phase of work, while more detailed offshore wind characterization will be reflected in Phase 2's operational modeling.

Key data sources for the assessment included:

+ Where possible, E3 relied on data provided by the utilities in response to data requests to all utilities; utility data was provided directly by Nova Scotia Power and Maritime Electric (PEI).
+ As a secondary source, E3 supplemented this data with the Integrated Resource Plans (IRPs) and Resource Adequacy (RA) studies for each utility.
+ Where necessary, E3 confirmed data against references on federal and provincial policy.
+ E3 also benchmarked and/or supplemented data with information based on public sources and/or previous studies developed for the Atlantic Canada region.

For certain inputs, notably candidate resource costs and fuel prices, where it was particularly important to ensure alignment and consistency across provinces, E3 relied on its proprietary market price forecasts, which are thoroughly vetted. Across data inputs and sources, E3 leveraged expertise and feedback from this study's Project Management Committee and Technical Committee. This information is summarized in Table 1 below.

Table 1. Key Modeling Assumptions

Category	Assumption
Area & Topography	+ Each Atlantic Canadian province is represented as a zone with loads and both existing and candidate resources defined for capacity expansion analysis. + For Newfoundland & Labrador, only the Newfoundland (Island System) is modeled as a load zone, with the Labrador-Island link represented as a capacity and energy resource supplied by Muskrat Falls and Churchill Falls power purchases from Labrador. + New Brunswick is externally connected to the Québec and ISO-NE markets.
Imports & Exports	+ Firm capacity contract obligations (Table 2) are represented from Newfoundland to Nova Scotia (Nova Scotia Block), New Brunswick to Prince Edward Island, and New Brunswick to Northern Maine. + Imports from Québec to New Brunswick are limited to historical import levels. + Imports and exports between New Brunswick and ISO-NE are flexible in the model and influenced by ISO-NE market prices (E3's Market Price Forecast).
Electricity Demand	+ Annual and peak load forecasts (Figure 3 and Figure 4) - consistent with utility planning and generally aligned with scenarios that achieve economy-wide net-zero goals. + Electrification levels based on utility planning assumptions in IRPs/RA studies; pulled scenarios as aligned with net-zero as were publicly available. + Given no utility data provided, additional electrification components of annual load forecasts for NB and NL were estimated from public sources during Phase 1.
Carbon Emissions Policy	+ Carbon price (Output-based pricing system) for electricity generation increases from \$50/tonne in 2022 to \$170 CAD/tonne by 2030 + Generator-specific emissions standards for OBPS used based on fuel type consumed and whether a generator is existing or new. The federal standards are adjusted in New Brunswick and Nova Scotia given legislated provincial-specific OBPS standards. + Potential future clean electricity regulations, which were not released at the time of this study, were modeled as a maximum annual CO_2e emission is 100g/kWh starting in 2035 and enforced for each province individually

Resource Adequacy	+ A Planning Reserve Margin (PRM) required to achieve a reliability standard of 1-day-in-10-year is defined in "UCAP" terms for each province.[5] + Renewable and storage resources' contribution to system reliability is based on their effective load carrying capability (ELCC). Offshore and Onshore Wind are assumed to contribute through the same ELCC curve, with contributions scaled based on capacity factor.[6] + Non-renewable resources contribution to system reliability is based on their seasonal ratings as well as their expected force outage rates. + New Brunswick firm capacity requirements include obligation to serve PEI as well as Northern Maine. + The Nova Scotia Block contract through the Maritime Link contribute to the firm capacity requirement in Nova Scotia, with a matching offset in the firm capacity value the Labrador-Island Link provides to the Newfoundland Island System. + The Labrador-Island Link firm capacity value is also affected by its potential outages in alignment with publicly available data.
Existing and Planned Resources	+ Existing resources and their operational characteristics are based on publicly available and utility-provided data, as well as Energy Exemplar (PLEXOS owner) database. + Planned resource additions before 2030 are modeled as fixed builds. + Announced planned unit retirements or conversions are modeled as fixed, with other resources later allowed to economically retire as well.
Candidate Resources & Costs	+ Candidate resource potentials and other attributes are based on publicly available data from the utilities and data provided by them for Phase 1. + Candidate resource costs, performance, and financing assumptions based on cost projections derived from National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) and include interconnection costs. + Renewable generation profiles come from data provided by the utilities as well as simulated from NREL.
Transmission Headroom[7] & Costs	+ Assumes system headroom for new candidate resources to be 860 MW in New Brunswick, 500 MW in Nova Scotia, and 500 MW in Newfoundland and Labrador. + Once resource additions exceed those amounts, incremental builds incur additional transmission delivery fees, modeled as a $300/kW deliverability adder.

[5] The study recognizes that N&L uses 2.8 loss of load hours as its target, given the need for the model to use the same target across provinces. This simplification is not expected to materially affect any results.

[6] This assumption will be investigated in greater detail as part of Phase 2.

[7] Transmission headroom refers to the unused capacity on the electricity transmission system that can accommodate additional power flows without overloading the grid.

Onshore and Offshore wind	+ Offshore wind potentials, profiles, and capacity factors are adjusted and developed for Phase I based on ongoing research in the region and technical stakeholder feedback, and outlined in more detail below. + Transmission deliverability cost adders implied for new wind resources based on data provided by the utilities. + Onshore and offshore wind integration requirements for capacity expansion modeled at $2/MWh (variable cost associated with production)
Fuel Costs	+ Fuel price forecasts are based on E3's in-house modeling combining short-term and long-term fuel price forecasts in the region, and the Energy Information Association's Annual Energy Outlook (AEO)[8] in the long term. + Natural gas fuel prices include representation of high increases in winter months when LNG imports in the Northeast are often on the margin.
Hydrogen Loads	+ An estimate of feasible hydrogen demand was developed based on considering both domestic consumption as well as export opportunities, from E3 PATHWAYS model, as described below and shown in Figure 5 and Figure 6. That said, the study is agnostic as to where hydrogen produced is used and focuses instead of a range of potential hydrogen production levels and the implication for offshore wind needs.

Regional Load Forecast

The study leverages province-level load forecasts to reflect the evolution of electricity demands over time, based on input from the utilities and public planning documents where utilities did not provide data directly[9]. To the extent feasible given data, E3 selected load forecasts that reflect energy demand growth in the Atlantic Provinces in alignment with economy-wide net-zero goals. The pace and electrification strategy varies to some extent by province. To translate annual load forecasts into hourly demands, E3 leveraged utility input and public reports where possible, and when needed, relied on its robust in-house load shaping toolkit to model the evolution of hourly load profiles, including layering on load profiles for electric vehicles and heat pumps on top of historical system load profiles to create hourly shapes consistent with net-zero. We note, however, that potential but today uncertain new large loads associated with potential new data centers were not layered into this analysis.

The primary impact of building electrification in the region is through space heating loads, with gas furnaces and electric resistance heating being replaced by a range of heat pump technologies. This means some demand previously served by natural gas shifts to the electric sector, increasing annual and peak demand. Meanwhile, the replacement of electric resistance heating with more efficient heat pumps reduces annual demand on the grid and, especially in the case of hybrid heat pumps, reduces peak demand. Overall, annual and peak energy demand is expected to increase in all provinces, especially in the winter months.

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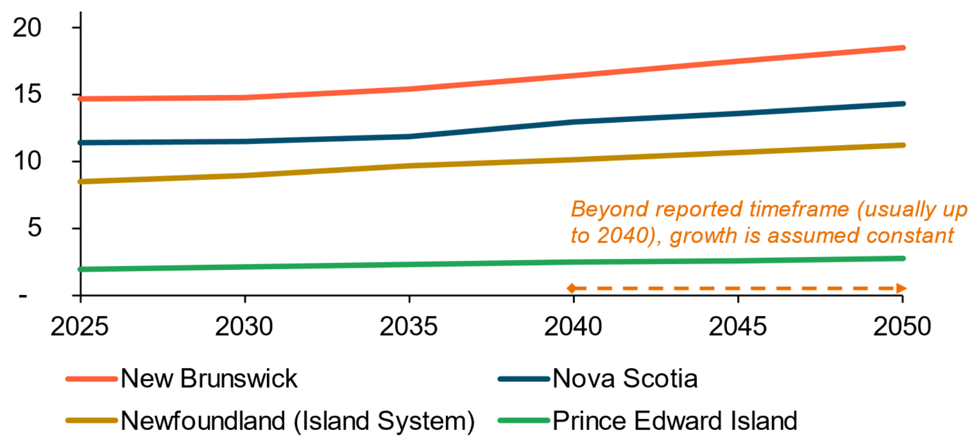
[8] https://www.eia.gov/outlooks/aeo/

[9] This includes New Brunswick Power's 2023 IRP and NL Hydro's 2024 Resource Adequacy study.

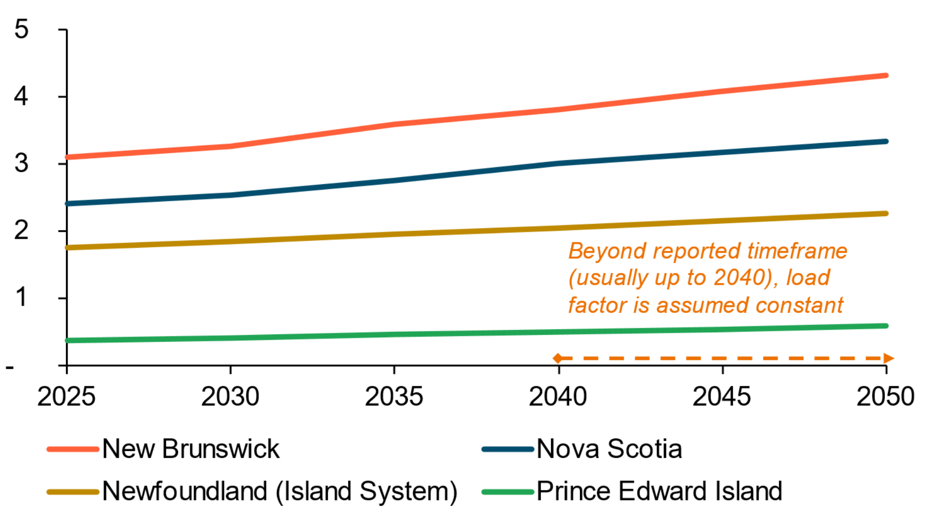
Transport electrification has a significant impact on annual and peak demand as well, with a higher impact on winter months given electric vehicle charging and battery efficiency fall significantly at low temperatures. The resulting annual energy demand and winter peaks for all provinces increase considerably, which drives the energy and capacity need on the grid as the system evolves. The annual loads and peak loads are shown in Figure 3 and Figure 4 below.

Figure 3. Annual Energy Demand (TWh)



Notes: The load forecasts are based on information provided directly by the utilities (Maritime Electric and NSP) and where not provided, from public sources (NB Power 2023 IRP and NL Hydro 2024 RA Study). These forecasts include assumptions related to demand-side management (DSM). We note that any BTM solar generation is not netted from load and modeled as a supply side resource. These figures are prior to layering on additional hydrogen loads, and do not assume new data center load materializes.

Figure 4. Annual Peak Demand (GW)



Notes: The load forecasts are based on information provided directly by the utilities (Maritime Electric and NSP) and where not provided, from public sources (NB Power 2023 IRP and NL Hydro 2024 RA Study). These forecasts include assumptions related to demand-side management (DSM). We note that any BTM solar generation is not netted from load and modeled as a supply side resource. These figures are prior to layering on additional hydrogen loads, and do not assume new data center load materializes.

Import and Export Assumptions

The study models the loads and resources of the four provinces, with a key focus on capturing the evolving dynamics between them to assess the implications of integrating high levels of offshore wind. Imports and exports within the Atlantic Provinces are primarily modeled as flexible and economically driven to capture the evolving dynamics of the system as resource portfolios and demand evolves in different locations – leading to different flows than observed historically and today. However, firm contracts are still represented between New Brunswick and PEI and between Newfoundland & Labrador and Nova Scotia (Nova Scotia Block). These contracts are not modeled as "must-take" fixed flows on an hourly energy basis within the representative periods in capacity expansion, but are accounted for in the planning reserve margin and firm capacity requirements in each zone.[10]

The island system of Newfoundland, part of the province of Newfoundland & Labrador, is modeled as its own zone separate from the Labrador northern part of the same province. This representation is aligned with how planning and reliability analysis was performed in the NL Hydro 2024 Resource Adequacy study, given this was the primary available source of data, and enables the explicit modeling of the Labrador-Island Link (LIL) as a key transmission resource connecting the island system Newfoundland to the extensive hydro generation in Labrador. The Labrador-Island Link is modeled as an energy source as well as a capacity resource for Newfoundland and the Nova Scotia Block – after accounting for its expected outage rates. This allows the model to represent how the Labrador-Island Link is a constraint which makes Newfoundland a distinctive load and resource zone within the province, despite the large amounts of hydro energy available in Labrador from Muskrat Falls and Churchill Falls contracts.

Table 2. Internal Market Interfaces Assumptions Summary

Interfaces within Atlantic Canada	Transmission Nameplate Capacity	Firm Capacity
New Brunswick – Prince Edward Island	300 MW bi-directional	300 MW from NB to PEI
New Brunswick – Nova Scotia	150 MW from NB to NS, 300 MW from NS to NB	None
Newfoundland – Nova Scotia	500 MW bi-directional	Nova Scotia Block, 153 MW

[10] For example, the New Brunswick reliability requirement is increased by the 300 MW it is obligated to serve as firm to Prince Edward Island, while the latter's reliability requirement is be reduced by the same 300 MW.

Labrador-Island Link	700 MW from Labrador to Newfoundland[11]	Firm capacity was derated based on line ratings reported in 2024 RA study, given forced outages

The Atlantic Provinces have three main interfaces with external markets: the New Brunswick and ISO New England interface (NB-ISO-NE), the Hydro Québec and New Brunswick Interface (HQ-NB), and a Nova Scotia and ISO New England interface (NS-ISO-NE) constructed in sensitivities designed to enable Offshore wind export opportunities. The first two have flow components established based on 2023 historically observed month-hour average flows.[12] NB-ISO-NE flows are fixed to the observed export flow pattern from New Brunswick to ISO New England. HQ-NB flows are more flexible. HQ-NB flows are enabled to import to New Brunswick at hourly quantities less than or equal to the observed import pattern from HydroQuébec to New Brunswick but can also export as much as 1,000 MW (based on previous E3 work) in the reverse direction. The flexibility in HQ-NB flows is modeled to enable deviations from historical New Brunswick imports to allow offshore wind energy an opportunity to export when economically viable rather than be curtailed. The MW transfer capacity of the NS-ISO-NE intertie is designed to expand to match the installed offshore wind capacity built in export cases. In this phase, NS-ISO-NE is an export-only interface with no imports enabled from ISO New England to Nova Scotia. Additional information related to assumptions is available in Appendix B, including historical average flows.

Hydrogen Load Forecast

In decarbonization planning across the globe, hydrogen has emerged as a potential solution for hard-to-decarbonize applications, including heavy industry and refining, aviation, and shipping, as well as a source of power generation during challenging conditions. A key strategy to produce zero-carbon hydrogen is to use electrolysis powered by renewable electricity.[13] Given the high capacity factor of offshore wind, there has been significant interest in using offshore wind to power electrolysis in the Atlantic Provinces, which would create significant new electricity demand. As shown in Appendix Section B.4, there are at least a dozen known projects at various stages of planning across the Atlantic Provinces today, with most focused on exports using onshore wind in the near-term.

[11] Study management committee members indicated that this transmission capacity may increase in the future to 900 MW, pending ongoing testing.
[12] https://tso.nbpower.com/Public/en/system_information_archive.aspx
[13] Electrolysis involves breaking water into hydrogen and oxygen using an electrical current.

While it is difficult to predict the most probable applications for the hydrogen demands, and, in particular, the balance of hydrogen for domestic consumption versus hydrogen for export markets, E3 assessed possible hydrogen demands to inform a range of potential electrolysis loads that offshore wind might support. The assessment of potential demands should not be interpreted as the definitive end uses for the hydrogen produced: rather, the goal is to assess a range of potential hydrogen loads served by offshore wind, and this approach allows us to benchmark this range to end uses that we can measure.

First, as a proxy for a "base" level of hydrogen production, E3 estimated the amount of domestic hydrogen demand that could be utilized regionally, agnostic to low-carbon hydrogen power source, as part of an economy-wide net-zero future, roughly aligned with the load forecasts. E3 leveraged its E3 Atlantic Provinces PATHWAYS model, which includes representation of economy-wide energy demand by end use and province.[14] The model includes detailed accounting of residential, commercial, industrial, and transportation equipment lifetimes, benchmarked to public Canadian government databases and utility IRPs. This enables representation of the replacement of equipment and energy demands with different decarbonized strategies, including hydrogen, over time.

Hydrogen was assumed to serve key hard-to-decarbonize end uses in the economy, based both on E3's experience leading decarbonization and hydrogen modeling and research for major jurisdictions across North America; an updated review of the latest research and projects; and discussions with stakeholders and regional hydrogen experts. Based on this, E3 determined that the critical end use cases for hydrogen in the Atlantic Provinces could be:

- high-temperature industrial heating,
- heavy-duty vehicles,
- aviation,
- and small amounts of residential/commercial space and water heating.

Hydrogen could also directly replace thermal generation in power plants, if those plants are converted to burn hydrogen or new hydrogen-burning combustion CTs are built. We estimated the amount of hydrogen production that would be consistent with replacing the highest levels of thermal generation we see in a range of future utility planning scenarios.[15] If the regional power sector doesn't need or leverage this hydrogen production, we anticipate that it would additionally serve other end uses, like export markets.

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[14] PATHWAYS is an economy-wide energy and greenhouse gas scenario planning model developed by E3 to create decarbonization policy scenarios across multiple economic sectors. It is a long-horizon, infrastructure-based stock rollover model, with detailed representation of the buildings, industry, transportation, and electricity sectors. The E3 PATHWAYS model utilized to estimate hydrogen demands was initially developed as part of the 2020 Atlantic Clean Provinces study. More information about the tool is available here: PATHWAYS - E3. More information on inputs is available in the ACP Study.

[15] We note that we did not investigate the economics of burning hydrogen in the power sector in detail in Phase 1 of this study, given the focus on offshore wind. This is an item we may explore further in subsequent phases of this work.

Hydrogen could also replace other end uses, like oil and gas refining, green steel, and maritime shipping; however, given significant uncertainty regarding the future of those industries (former) and the lack of sector specific data (latter), we did not directly include these estimates in our hydrogen production forecast. That said, it is very possible that these other end uses could replace some of the hydrogen offtake from these other end uses, and we emphasize that the goal was to estimate a feasible range of hydrogen production levels, and then evaluate the role that offshore wind could play in meeting those demands and the implications for overall grid build-out.

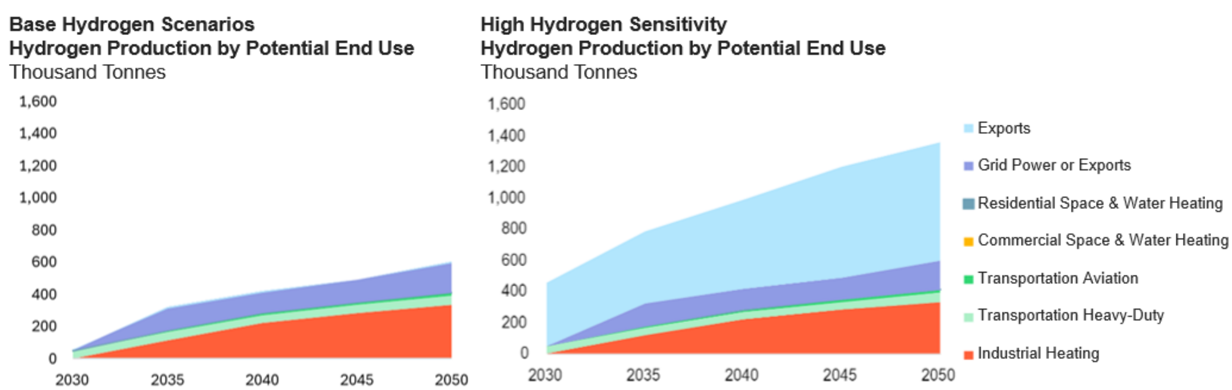
Export opportunities offer a potentially much larger but more uncertain offtake opportunity for hydrogen. On one hand, E3 analysis and certain reports on the global hydrogen outlook[16] find that hydrogen production in the Atlantic Provinces using offshore wind as the clean power source, faces high investment costs and is today expensive relative to the most cost competitive producers. However, significant momentum and interest in Atlantic Province-based hydrogen production, specifically as potential exports to European markets (i.e. the $300 million Canada-Germany Hydrogen Alliance agreement), could help to reduce costs and spur new investment.

Given the uncertainty related to exports, E3 developed two modeling scenarios for hydrogen production (to be served by onshore and offshore wind):

1. **"Base Hydrogen" scenario**, which is based on levels of hydrogen production consistent with domestic consumption and/or more limited exports
+ **"High Hydrogen" scenario**, which assumes expanded export opportunities for the Atlantic Provinces based upon current plans for hydrogen projects (with some attrition assumed[17])

The cumulative hydrogen production for these two scenarios is shown in Figure 5 below. Note that E3 discusses forecasts in terms of tons of hydrogen as a unit of comparison, but in the real world, the end use product might be derivatives of hydrogen like ammonia or electrofuels.

Figure 5. Atlantic Province Hydrogen Demand Projections

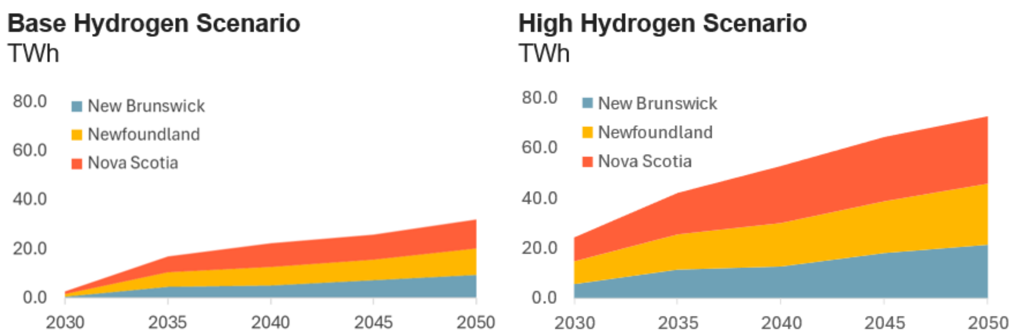


[16] Global Energy Perspective 2023: Hydrogen outlook | McKinsey

[17] This attrition accounts for the assumption that some fraction of currently proposed hydrogen development projects may not achieve operations or fulfill the required criteria for final investment.

The region-wide hydrogen load is allocated to provinces based on onshore and offshore wind potential to support electrolysis, as well as review of existing projects and expert input, as shown in Figure 6 below. The hourly hydrogen load shapes are provided in Appendix B.

Figure 6. Atlantic Province Electrolyzer Load Forecast[18]



Offshore Wind Cost and Potential Assumptions

Offshore wind presents an opportunity to expand clean electricity generation in the Atlantic Provinces, diversifying from the hydro, solar and onshore wind resources that exist today and are planned for the near-term future. To evaluate their potential role in serving new demand, Phase 1 of this study utilizes existing estimates of the geographic potential, estimated capacity factors, and estimated investment costs of offshore wind inclusive of costs to interconnect these resources to the existing electric grid on land.

Specifically, Phase 1 relies on ongoing research estimates to represent the potential development sites, and performance of offshore wind resources in Nova Scotia, and extends this work to the other provinces[19]. These assumptions will be updated in Phase 2 and 3, where the study is directly building out granular data on the technical, locational, and economic offshore wind potential; capacity factors, and costs.

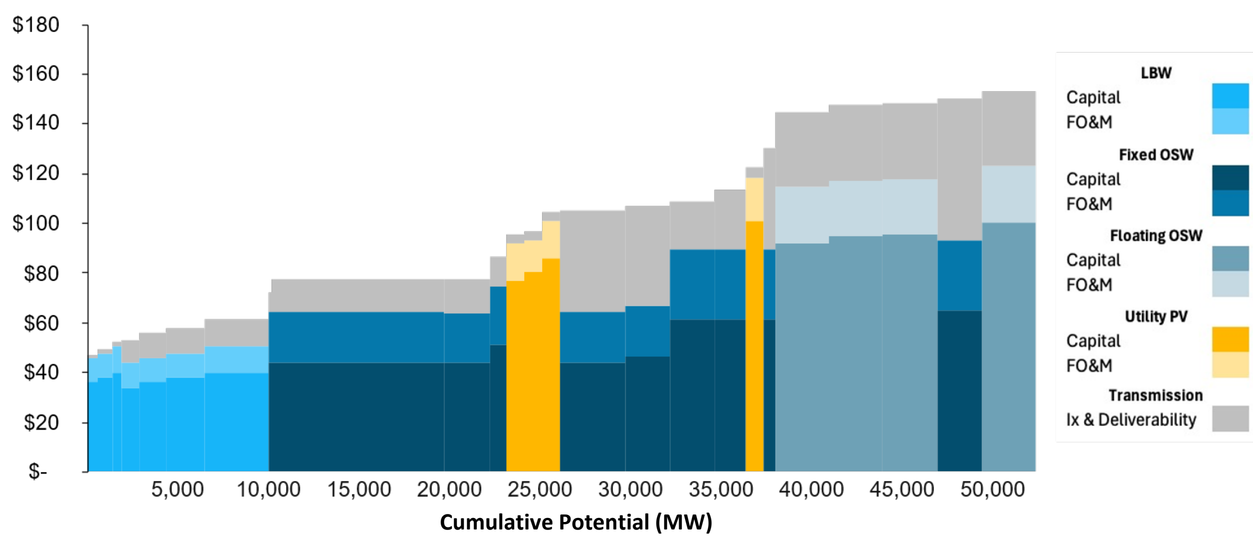
Offshore wind capital costs reflected projections from the NREL 2024 Annual Technology Baseline (ATB), modified based on province-specific land, labor, and tax costs. Fixed offshore wind resources were

[18] Hydrogen load is modeled as interruptible in this phase, under the assumption that load would be able to ramp down in the case of a loss-of-load risk or potential event.

[19] This work is based on draft information provided by L. Swan, with Dalhousie University's Renewable Energy Storage Lab, and will be updated in Phase 2. We do not anticipate that this will appreciably affect the size of the market opportunity.

modeled in higher granularity: resources were classified into 9 groups based on location, capacity factor, and interconnection distance. These groups were used to calculate site-specific interconnection costs based on their distance to shore, using a cost of $13.6/kW-km[20]. In addition to resource interconnection costs, onshore deliverability costs were also captured to ensure power delivered to shore would reach load centers. Initial tranches of new resources benefit from the "headroom" on the current system, after accounting for already contracted resources, while subsequent builds must pay for local deliverability upgrades. To capture this dynamic, our team estimated existing system headroom to be 860 MW in New Brunswick, 500 MW in Nova Scotia, and 500 MW in Newfoundland and Labrador. Once resource additions exceed those amounts, incremental builds incur additional transmission delivery fees, modeled as a $300/kW deliverability adder. Figure 7 below illustrates all-in investment costs (capital costs and fixed O&M) for each candidate renewable resource in our model in 2035[21], sorted from lowest to highest cost including interconnection and deliverability costs. The width of each bar reflects the total buildable potential (in MW) at a given all-in LCOE. Costs are broken into levelized capital costs, fixed operations & maintenance, and transmission, with the transmission costs comprising both interconnection and onshore deliverability upgrade costs as discussed above.

Figure 7. Renewable Supply Curve, Levelized Cost of Energy in 2035 ($2022 CAD/MWh)



Note: The figure shows the total cumulative resource technical potential considered in this phase of work. The LCOE values reported above are estimated prior to layering on any curtailment of resources.

Scenario Design

To assess the implications of different offshore wind market opportunities, this study analyzes several scenarios that vary the level and timing of offshore wind build-out, aligned with meeting different market

[20] This value was based on per kilometer offshore wind grid connection cost estimates from NREL ATB 2024.

[21] Note while we do incorporate the Canadian Investment Tax Credit in our resource cost modeling, by 2035 that credit has fully phased out under current law, and so it does not impact cost projections in this figure.

opportunity needs. A description of these scenarios is provided in Figure 8 below. These scenarios consider increasingly expansive offshore wind offtake opportunities, aligned with the levels of demand assessed as part of the regional data aggregation described in the input development section. All scenarios are incremental to the existing onshore wind on the system.

Our scenario design approach models offshore wind as a planned build to ensure that offshore wind build levels meet the specific targets to support different offtake opportunities. Under this approach, we can evaluate the overall system grid impacts of strategic or policy-driven offshore wind targets. As a counterfactual, E3 also ran a Reference scenario, which represents a business-as-usual future with existing and planned resources through 2030, and historical market interactions. The model can economically select the least cost set of resources to meet remaining system needs.

E3 also ran sensitivities on the hydrogen scenarios that use the "high" hydrogen levels as well as the base hydrogen levels. The total GW build-outs assumed for each scenario is described in Table 3, and shown graphically in Figure 9. E3 also ran an expanded transmission sensitivity, which increases NB-NS transmission, and is shared in the Appendix.

Figure 8. Future Scenarios Considered in this Study

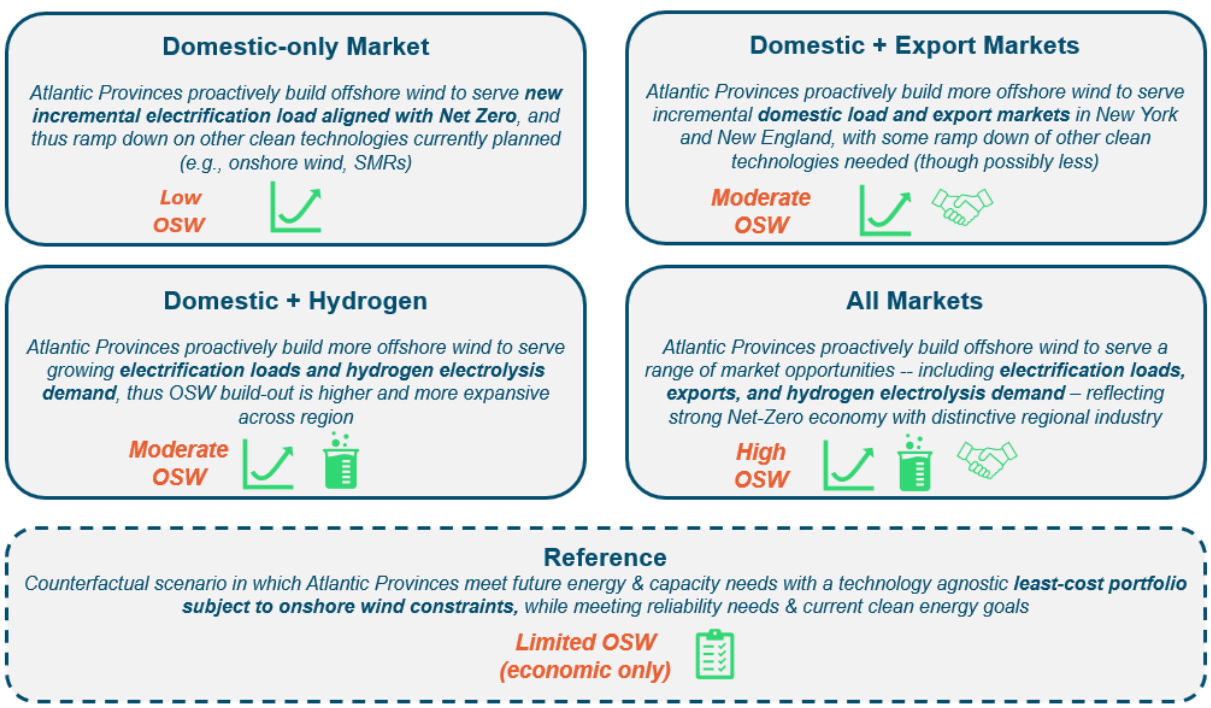


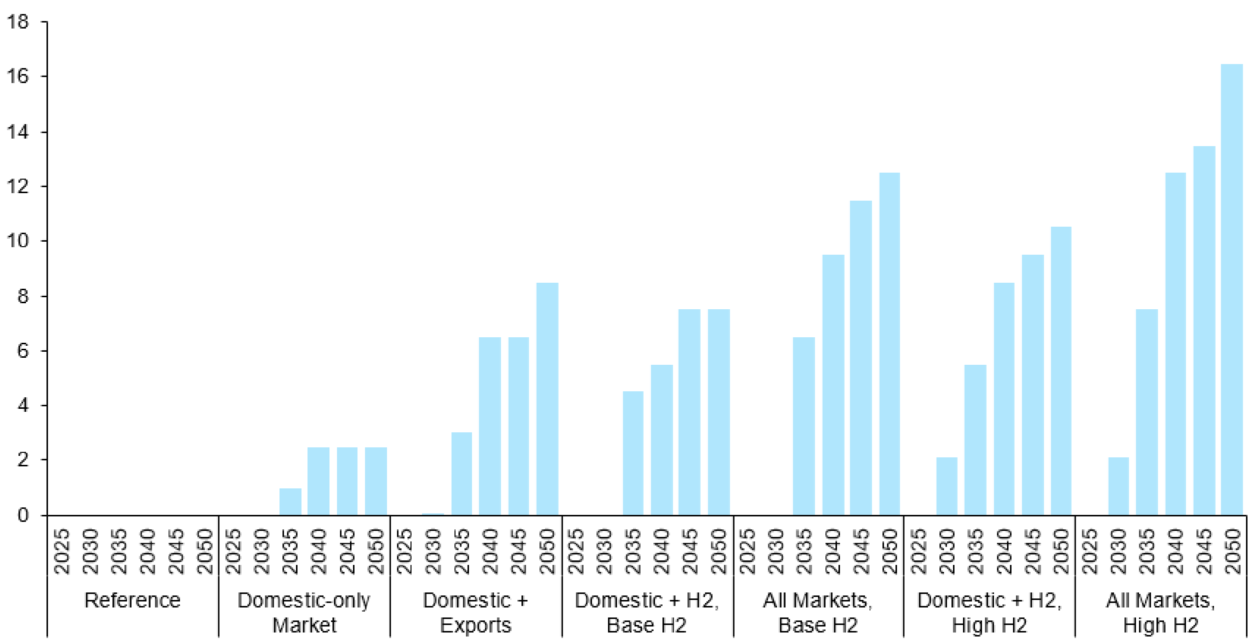
Table 3. Scenario Offshore Wind Builds

Scenario Name & Description	Offshore Wind Planned Builds (GW) 2030	2035	2040	2045	2050
Reference Reflects "business-as-usual" conditions	-	-	-	-	-
Domestic-only Reflects offshore wind serving the Atlantic Provinces	-	1	2.5	2.5	2.5
Domestic + Exports Reflects offshore wind serving the Atlantic Provinces and export markets	-	3	6.5	6.5	8.5
Domestic + H2, Base H2 Reflects offshore wind serving the Atlantic Provinces and potential hydrogen loads	-	3	5.5	6	6.5
Domestic + H2, High H2 Reflects offshore wind serving the Atlantic Provinces and potential high hydrogen loads	2	5.5	8.5	9.5	10.5
All Markets, Base H2 Reflects offshore wind serving the Atlantic Provinces, export markets, and potential hydrogen loads	-	5	9.5	10	12.5
All Markets, High H2 Reflects offshore wind serving the Atlantic Provinces, export markets, and potential high hydrogen loads	2	7.5	12.5	13.5	16.5

Note: Scenarios may still build additional offshore wind that is optimally selected by the model. We also note that the export scenarios built both offshore wind and increasing amounts of transmission export capability to transfer this energy to external markets.

Figure 9. Detailed Planned Offshore Wind Builds by Scenario

Capacity
GW



Additional Information on Wind Builds for Hydrogen Scenarios

Current and planned hydrogen projects across the Atlantic Provinces largely focus on onshore wind today, given this resource is cheaper, high performing and well established in the region. To reflect this, E3 assumes that hydrogen loads are met with a combination of onshore and offshore wind resources. The scenarios rely more heavily on onshore wind in the near-term, and transitions to supporting new incremental projects with offshore wind in the longer term, as costs come down and the region builds experience in this resource. In these scenarios, E3 models planned builds for onshore and offshore wind to support hydrogen as indicated below. The breakdown of the assumed buildouts are provided in Table 4 and Table 5.

Table 4. Base Hydrogen Scenario, Total Cumulative Capacity to Support Hydrogen Production* (GW)

Resource	Province	2030	2035	2040	2045	2050
Offshore Wind	Newfoundland and Labrador		1	1	1.5	2
	Nova Scotia		1	2	2	2
	Total	**0**	**2**	**3**	**3.5**	**4**
Onshore Wind	New Brunswick	1	1	1	1	1
	Newfoundland and Labrador		0.5	0.5	1	1.5
	Nova Scotia		0.5	0.5	0.5	1
	Total	**1**	**2**	**2**	**2.5**	**3.5**

* Note: This scenario assumes only a smaller portion of current potential projects reach commercial operation and connect to the regional grid. It does not account for additional projects that may be developed independently of the regional electric grid. These off-grid hydrogen projects could be significant and represent additional potential beyond what is modeled here.

Table 5. High Hydrogen Scenario, Total Cumulative Capacity to Support Hydrogen Production* (GW)

Resource	Province	2030	2035	2040	2045	2050
Offshore Wind	New Brunswick		1	1	1.5	2
	Newfoundland and Labrador	1	1.5	2	2.5	3
	Nova Scotia	1	2	3	3	3
	Total	**2**	**4.5**	**6**	**7**	**8**
Onshore Wind	New Brunswick	1.5	1.5	1.5	2	2
	Newfoundland and Labrador	1.5	3	4	5	6
	Nova Scotia	1.5	1.5	1.5	2	2
	Total	**4.5**	**6**	**7**	**9**	**10**

* Note: This scenario assumes a portion of current potential projects reach commercial operation and connect to the regional grid. It does not account for additional projects that may be developed independently of the regional electric grid. These off-grid hydrogen projects could be significant and represent additional potential beyond what is modeled here.

Results

The electric sector modeling produces electricity generation portfolios, by province, that meet projected electricity demand in each scenario, subject to the policy, operational, transmission and technological constraints described above and in Appendix B. As described in the prior section, the modeling approach is **scenario-based**: it incorporates offshore wind builds as a fixed, or planned, part of the future scenarios, illustrating the implications of buildouts on the overall system needs, costs, emissions and reliability.

In what follows, E3 describes key results and findings from this assessment, including the electric sector resource portfolios across scenarios, the generation mix and associated emissions, the change in regional electricity flows, and the resulting costs associated with different resource futures.

Electricity Resource Capacity Portfolios

The modeling produces electric sector capacity across the provinces for each year, from 2025 through 2050. In Figure 10 and Figure 11, E3 reports the total Atlantic Provinces electricity installed capacity and generation across scenarios, as well as for the Reference, which represents counterfactual conditions without a specific focus on building offshore wind.[22]

These results provide several key insights. First, absent specific policy to prioritize offshore wind, the model chooses to build primarily new incremental onshore wind to meet future energy needs across the region, driven by lower capital costs than offshore wind, particularly in the near term.[23] Of the total installed capacity, economically-selected and grid-connected onshore wind builds represent almost 1 GW in 2030 and 5.4 GW in 2050 without offshore wind targets; this is on top of the 1.2 GW of planned builds by 2030 and 1.2 GW of existing capacity. As offshore wind declines in cost, a small amount of offshore wind, about 170 MW, is economically selected by 2035 even without an explicit policy target imposed on the model. In scenarios with planned offshore wind builds (e.g., representing a generic strategy or policy to build offshore wind), this alleviates the need for the region to build out nearly as much new incremental onshore wind to meet demand. Given the higher capacity factors of offshore wind, new future incremental onshore wind buildouts are lower than the Reference on a slightly higher than one-for-one basis with offshore wind, in the Domestic-only Market scenario (roughly 2.8 GW less onshore wind for 2.3 GW additional offshore wind in 2050). In cases where hydrogen demand is added to the system, new incremental onshore wind build outs grow alongside offshore wind, representing the need to have a

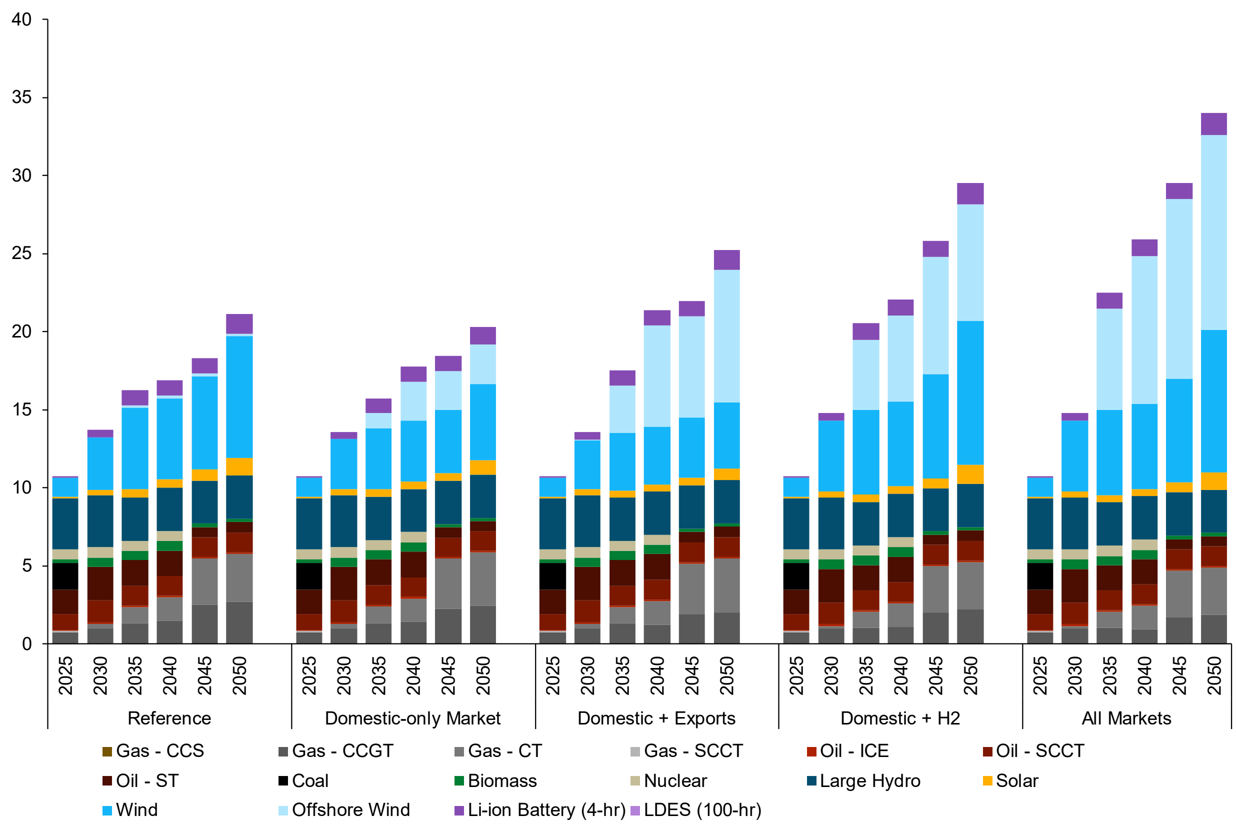
[22] Appendix A reports additional results for key sensitivities on transmission and hydrogen.

[23] Phases 2 and 3 will refresh both cost projections and the capacity accreditation approach, which may impact these findings

somewhat more diverse resource mix, in which more than 15 GW of total wind generation capacity is utilized.

Despite significant offshore wind investment, the model selects natural gas (CT and CCGT) capacity to support resource adequacy and very limited generation needs. This is because modeling to date suggests the most critical conditions for regional resource adequacy occur in winter mornings. Based on the Phase 1 offshore wind output profiles, the modeling reflects the ability of dispatchable gas generation to support system reliability during the occasional periods of high load and low wind generation, despite offshore wind's high capacity factors which ensure that it can *usually* support winter needs.[24] Given fuel and operating costs, and the carbon tax, the gas units are generally expensive to run outside of these periods of critical need, and so operate at very low capacity factors, contributing very low generation or emissions to the region.

Figure 10. Total Atlantic Provinces Capacity (GW) Across Scenarios



[24] The ability of offshore wind to support regional resource adequacy needs will be further assessed in more detail after the completion of the technical potential and detailed output characterization developed in Phase 2.

Electricity Generation

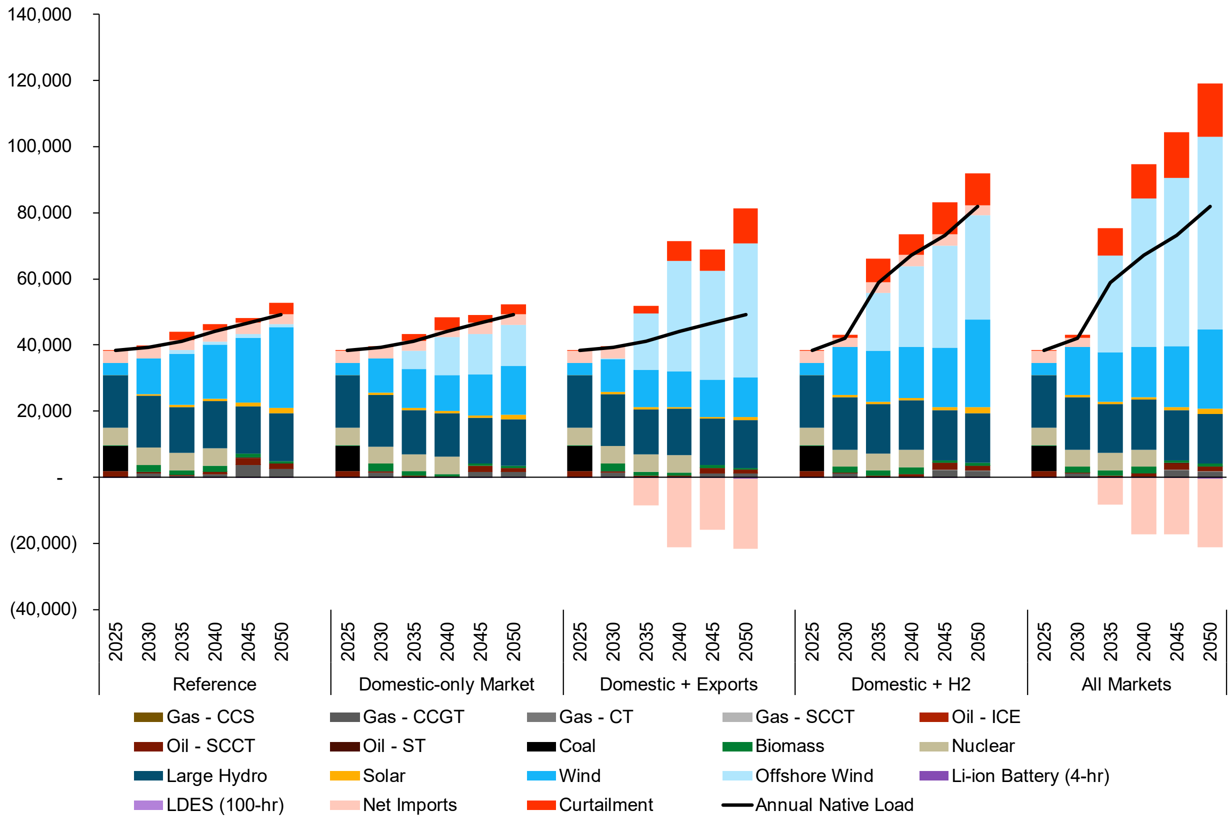
Given existing regional policy, most electricity demand is met with zero-carbon electricity across all scenarios by 2030, including the Reference scenario. When offshore wind is built as part of the scenario targets, it is able to provide a larger portion of overall clean energy end uses. As new load for hydrogen is introduced, or when new transmission/offtake opportunity via export markets is offered, this also drives greater demand, or offtake opportunity from the perspective of investors, and much higher levels of offshore wind generation.

With its higher capacity factor, offshore wind generation provides significant system-level support during both on-peak and off-peak hours. During winter months in the Domestic-only Market scenario, offshore wind provides an average of 13% of total generation in 2035 and 25% of total generation in 2050. However, this also leads to significant curtailment during off-peak conditions.

Notably, thermal generation remains largely unchanged across scenarios. Thermal generation provides dispatchable capacity during times of need, warranting continued operation in a select number of hours even with high offshore wind penetration. Deeper investigation of the role of offshore wind vis-à-vis thermal generation will be explored in Phase 3. Additionally, the quality and quantity of offshore wind generation within the Atlantic Provinces capitalizes on the export market opportunity to ISO-NE from Nova Scotia, as described below.

Finally, in the Phase 1 capacity expansion model, generation dispatch only occurs over the 36 representative sample days within the model. In Phase 2, E3 will evaluate the portfolios using hourly production simulation modeling, generating more precise estimates of hourly dispatch under a range of system conditions, refining the characterization of offshore wind's interaction with other resources.

Figure 11. Total Atlantic Provinces Generation (GWh) Across Scenarios



Electricity Interprovincial Flows and Exports

A key enabler of offshore wind offtake is the ability to move it across provinces. The Phase 1 assessment modeling focused on the existing interprovincial transmission links and corresponding flows, with limited representation of additional new transmission largely focused on the ability to move clean energy to external markets. In Phases 2 and 3, the study will more deeply explore interprovincial and external linkages, expansion potential, and interactions between interprovincial transmission and economically selected offshore wind resources.

Regardless, the existing transmission links between provinces are already critical for serving load and economically dispatching new resources. The Nova Scotia to New Brunswick tie is particularly important across scenarios, given the wind potential in Nova Scotia and the load growth projected in New Brunswick. This can be observed even in the Reference scenario, where line utilization increases from Nova Scotia to New Brunswick between 2030 and 2050, as shown in Figure 13.

Cases with high levels of offshore wind builds drive even higher levels of line utilization between Nova Scotia and New Brunswick, as seen in Figure 23 in the "Market Opportunity to Support Exports" section. In many hours that intertie is at max capacity in these cases, leading to some offshore wind curtailment when there is excess generation feeding into Nova Scotia but no additional ability to export it. Even in scenarios with expanded transmission capacity to ISO-New England, energy exports are not always financially viable and the line limits between Nova Scotia and New Brunswick (300 MW in the New Brunswick direction) inhibit excess Nova Scotia offshore wind from being exported to New Brunswick. This excess is then curtailed as shown in Figure 12. In Phase 2 and 3, more detailed hourly modeling and a broader range of strategies for reducing curtailment will be explored.[25]

[25] It is expected that these phases will generate updated and more precise curtailment estimates, given that Phase 1 relies on sample day modeling rather than full hourly modeling with operational constraints.

Figure 12. Annual Generation (GWh), All Scenarios, by Province

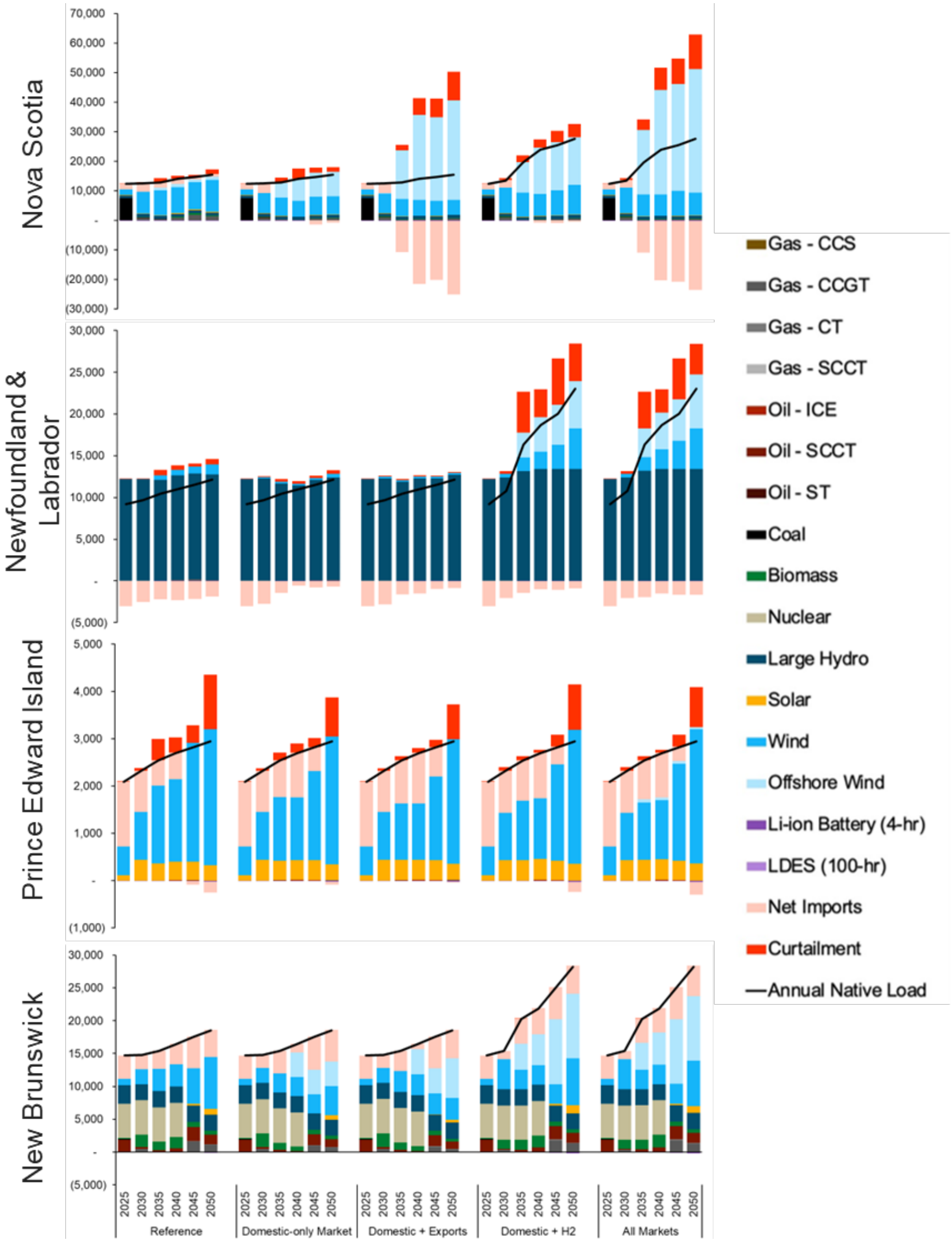
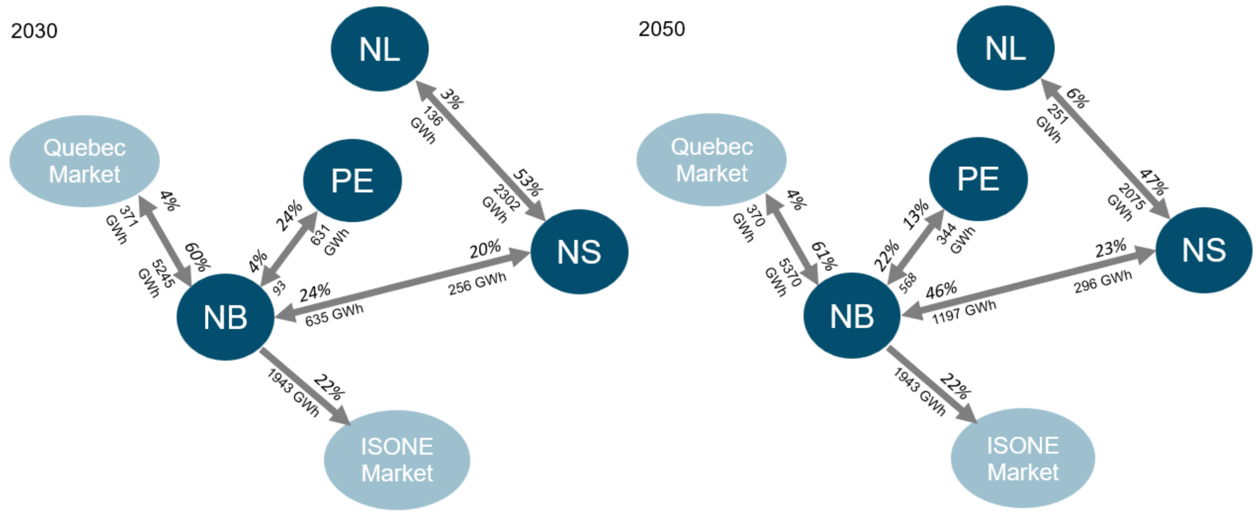


Figure 13. Reference, Line Utilization (%) and Flows (GWh) for 2030 and 2050



Note: This is the Reference case, in which no additional transmission is built to New England or across provinces. Figure 23 below illustrates scenario flows when additional transmission to New England is built. This study does not directly model transmission linkages between Labrador and Hydro Quebec due to lack of publicly available data on Labrador loads and import/export flows between Labrador and Quebec. Instead, flows south across the Labrador Island Link are captured, as is full load/resource representation for the Newfoundland Island System and the links to Nova Scotia. Together, these capture the interactive effects of Labrador-based generation on resource portfolios and dispatch elsewhere in the region. For additional detail on model set-up see the "Modeling Framework" section above.

Scenario Cost Comparison

The study models the cost of the electric grid as investments are added to meet increasing load and system needs.[26] PLEXOS minimizes the sum of generation-related new fixed costs and system operating costs, discounted to the present year. Fixed costs include investment in new generating resources and any associated interconnection and transmission required to deliver clean energy to loads, as well as fixed O&M and any associated variable O&M costs. Fixed costs are reduced when existing resources are retired. Variable costs include fuel and variable O&M, which are reduced as incremental clean energy resources are added and utilization of fuel-based resources declines. The cost of imports reflects the total energy costs associated with these imports, and the revenue associated with exports reflects the energy revenues earned.

Consistent with decarbonization planning expectations in most jurisdictions, total power sector costs in the Atlantic Provinces are projected to increase in all scenarios. This is driven by a range of factors, including load growth, the need for new local transmission, and the development of a new, non-emitting

[26] Note that this does not include the fixed costs associated with the existing system and utility planned/under construction resources through 2030, and therefore is not itself a full representation of system costs or revenue requirements. However, it does reflect key elements of costs that might ***vary or differ*** across scenarios and pathways.

generation fleet. Offshore wind development specifically plays a role in that, and the model shows higher costs in scenarios with greater planned offshore wind deployment. This is expected since offshore wind has higher cost expectations relative to onshore alternatives, though it is partially mitigated in scenarios with greater export market access, as sales to neighboring regions improve the economic viability of offshore wind projects.

Figure 14 below helps illustrate these dynamics across cases. This chart shows the modeled annual cost of energy across scenarios, expressed in nominal cents per kWh. The annual cost of energy rises in all cases relative to the reference case, with the domestic market only case showing only a modest increase (0.67 cents per kWh nominal in 2050 above reference), and the other scenarios that model larger offshore wind builds (and in the case of the hydrogen scenarios, higher loads as well) showing more meaningful increases (about 2-2.5 cents per kWh in 2050 above reference, after accounting for export revenues).

Figure 14. Modeled (Partial) Cost Comparison, Difference in Annual Cost of Energy (nominal ¢/kWh) Relative to Reference Across Scenarios

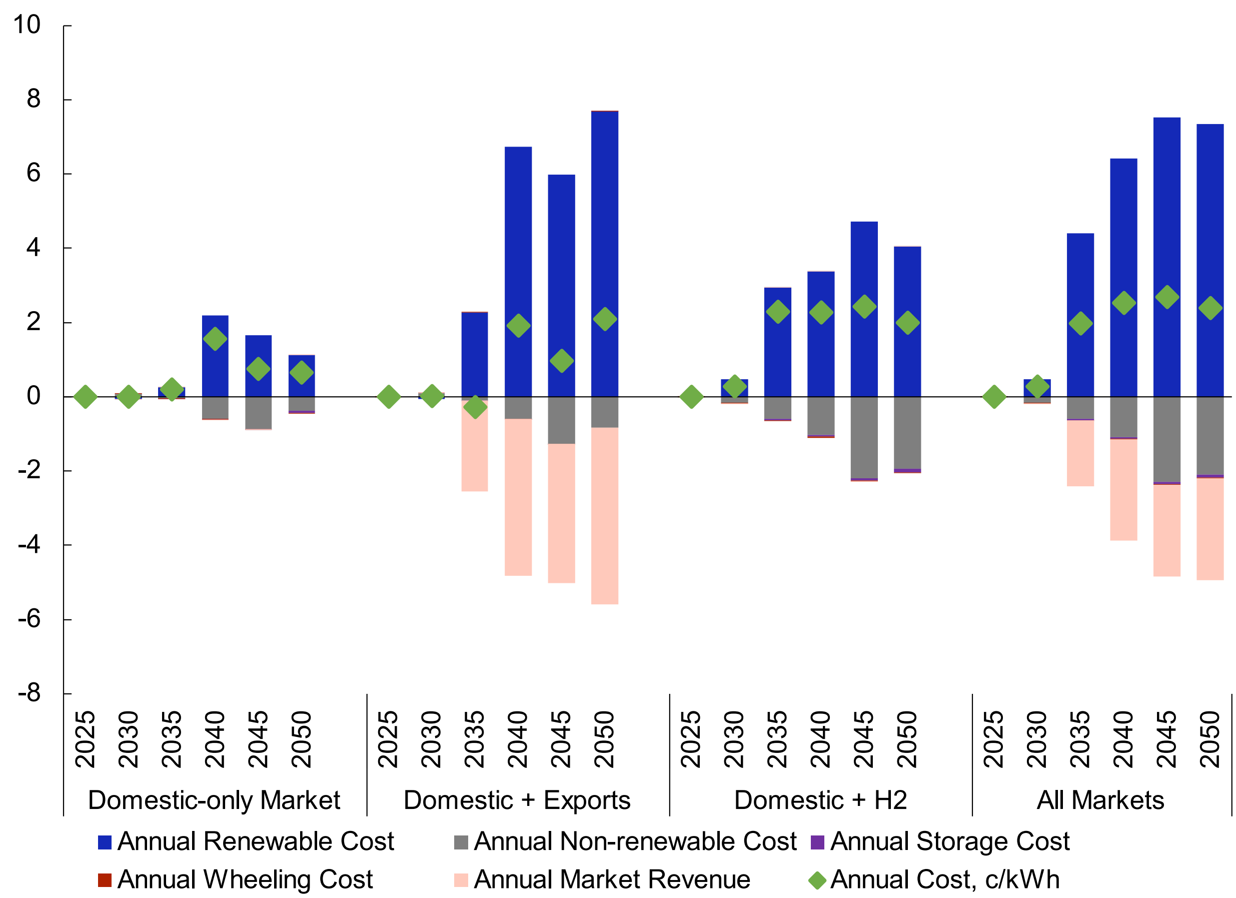
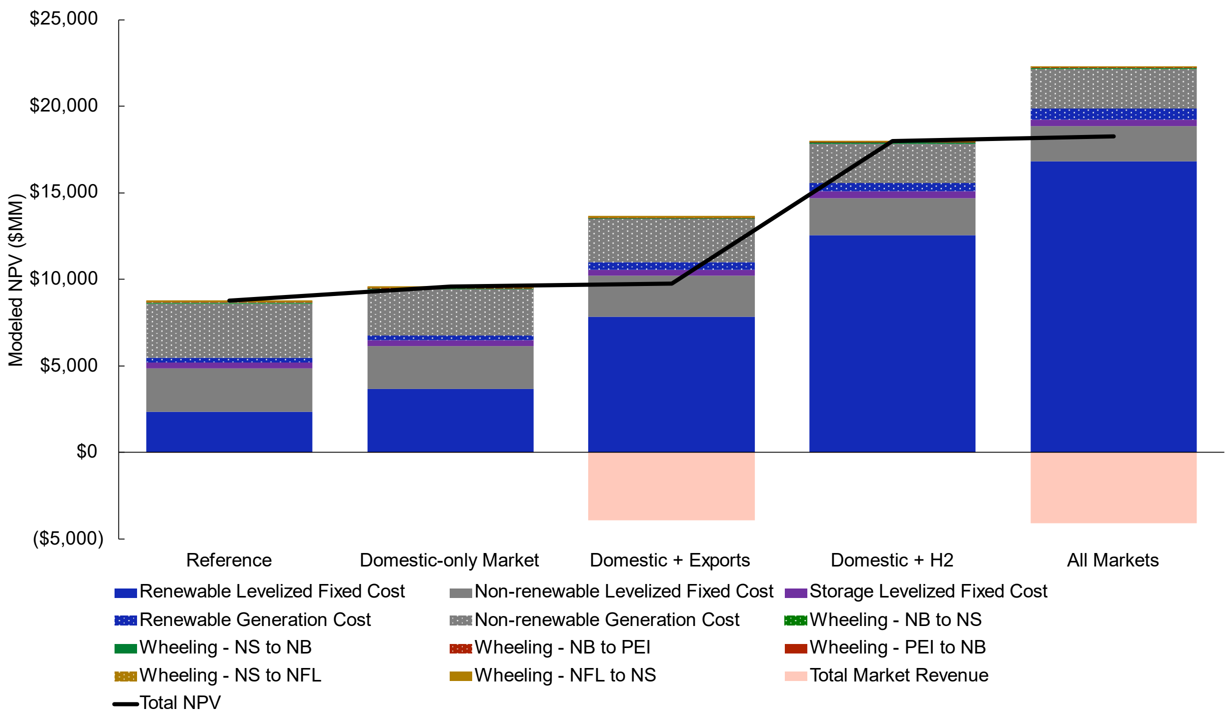


Figure 15 shows the modeled net present value (NPV) across scenarios. The NPV of total costs similarly increases across scenarios, reflecting the cumulative impact of offshore wind investments and, for the hydrogen cases, increased loads. The NPV of renewable fixed costs in the All Markets scenario rises from $1.8 billion in 2030 to almost $8 billion by 2050. Both renewable and non-renewable generation costs show gradual increases, though fossil generation costs decrease in scenarios prioritizing offshore wind.

Wheeling costs increase with higher offshore wind penetration as interprovincial energy flows grow to balance supply and demand. These costs become relevant in scenarios with significant export market integration, such as the Domestic + Exports and All Markets scenarios. In the Domestic + Exports and All Markets scenarios, market revenues from ISO-NE and other external markets provide significant offsets, lowering the overall NPV.

Figure 15. Modeled Cost Comparison, Total Net Present Value (NPV) Across Scenarios



In Table 6, E3 compares the modeled annual cost of energy and NPV in 2050 of all scenarios compared to that of the Reference scenario. This table summarizes the key cost trends, highlighting cost increases as offshore wind penetration and market complexity (hydrogen and exports) increase across scenarios.

Table 6. Modeled Cost Comparison, Annual Cost of Energy and Net Present Value Compared to Reference Scenario

Scenario	Annual Modeled/Partial Cost of Energy, 2050 (¢/kWh)	Percent Increase vs. Reference	NPV as of 1/1/2024, 2025-2050 ($billion)	Percent Increase vs. Reference

Reference	7.08	-	$12.6	-
C1, Domestic-only	7.75	9.4%	$15.1	20.0%
C2, Domestic + Exports	9.18	29.6%	$17.3	37.3%
C3, Domestic + H2	9.08	28.2%	$17.9	41.6%
C4, All Markets	9.49	34.1%	$19.5	54.6%

Note: This has not been benchmarked to retail rates in Phase 1. These estimates will be refined and benchmarked to total energy costs in Phase 2. Annual Modeled/Partial Cost of Energy reflects new investment and operational costs in 2050. Note that the cost of new transmission to New England are not factored into the above costs.

While offshore wind integration is costly, its potential strategic value lies in its ability to help meet decarbonization targets, earn revenue from export markets if conditions are favorable, spur job growth and industrial development in the region, and potentially provide other benefits. Revenue from exports to New England could improve the economic case for offshore wind but overall impacts on system costs from the associated incremental offshore wind builds become dependent on energy prices in those markets, as well as the costs of transmission to those markets. The New England price strip utilized in the Phase 1 analysis includes substantial offshore wind development in the New England market as well, which depresses prices during many of the hours that offshore wind from Atlantic Canda is available; substantial delays or reductions to this resource buildout in New England could have material impacts on the revenue generated from offshore wind exports in Atlantic Canada. These markets align with Canada's decarbonization goals and provide a critical value stream. The extension of tax incentives beyond 2034 could significantly reduce upfront capital costs and enhance overall cost-effectiveness. This would reduce the cost of offshore wind deployment in the Atlantic Provinces. The study also does not model the costs of new transmission to New England; this cost and its allocation across parties will influence the viability of export markets.

Market Opportunity to Support Domestic Consumption

Domestic loads in the Atlantic Provinces absorb about 1 GW of offshore wind development by 2035, increasing to 2.5 GW by 2040, with that level maintained through 2050. At these build levels, the system can relatively easily integrate and utilize the offshore wind, particularly during times of need in the winter, and little offshore wind curtailment is observed (though more precise curtailment estimates to be developed in Phase 2). As the Atlantic Provinces decarbonize their electric grid, electrification of vehicles and buildings increases loads annually, as well as coincidentally with higher winter offshore wind generation patterns. Select dispatch charts across provinces, shown in Figure 16 and Figure 17, help illustrate these dynamics. The phase-out of coal and other fossil fuel-based generation adds to the system need for new generation to serve growing loads. Given these dynamics, offshore wind has the potential to support the Atlantic Provinces achieving their decarbonization goals.

In addition to diversifying and expanding the region's clean energy supply, early investments in offshore wind could create a range of additional benefits. These include economic development and job creation through the growth of an offshore wind industry, leveraging the region's strong marine-oriented workforce and research expertise. Such investments can help position the Atlantic Provinces as leaders in offshore wind technology, building on existing strengths in marine innovation. Regional offshore wind development also supports reduced reliance on imported energy and fuels, enhancing energy security and resilience to global market disruptions.

Despite its potential, this remains a higher-cost pathway under current cost projections compared to scenarios that rely more heavily on onshore wind to meet domestic needs. A limited amount of offshore wind becomes cost-effective over time, and anticipated cost declines in the medium to long term could improve its competitiveness. Moreover, constraints on land availability for onshore wind development may further enhance the relative attractiveness of offshore wind.

While many enablers are needed for offshore wind development to support domestic markets, key focus areas identified through the regional assessment included:

- **Lowering costs:** As noted throughout the report, offshore wind remains significantly more expensive than onshore wind today. However, as land becomes increasingly constrained, particularly in provinces like Nova Scotia, offshore wind may offer a valuable alternative. To reduce costs, it is important to identify offshore sites with high quality offshore wind resources and the least transmission need, and to identify transmission configurations that maximize infrastructure utilization, thus making per-unit output more cost effective. At the same time, the region should leverage its maritime expertise to drive down development costs—through greater coordination across marine industries and by applying shared knowledge in building, operating, and maintaining infrastructure in coastal environments.
- **Ensuring regional coordination**: Modeling results show relatively low curtailment in the Reference and domestic consumption-focused scenarios, indicating sufficient transmission capacity to move wind power to areas of demand. However, in scenarios exploring broader offtake opportunities, curtailment increases, particularly where offshore wind buildout is higher. Enhancing transmission into New Brunswick, for example, would support greater utilization of offshore wind and help reduce curtailment. More broadly, strengthened regional coordination will allow electricity to flow more efficiently across provinces, reducing congestion and improving overall system reliability.

While not the primary focus of this study, several additional enablers are essential to support offshore wind development and will be further explored in the overall Roadmap. These include, but are not limited to, challenges related to workforce development, permitting and siting policies, and regional supply chain growth.

In subsequent phases, the study is evaluating key modeling uncertainties and pursuing refinements that include:

- Modeling to-date identified modest offshore wind curtailment in this scenario, indicating potential for this scale of offshore wind development to help serve domestic loads. However, as a zonal capacity expansion analysis utilizing sample periods, this doesn't capture conditions in all hours of these modeled future years, nor does it capture sub-zonal constraints. Refined resource representation as well as the hourly dispatch analysis that E3 will conduct in Phase 2 will provide additional insight into the load service and curtailment challenges of these resources.

- Existing inter-provincial transmission constraints from locations with offshore wind interconnection and load centers limit offshore wind development scale. Deeper assessment of inter-provincial transmission, as well as improved offshore wind resource characterization in other provinces that Stantec and WindSim are working on in Phase 2 will improve our understanding of these dynamics and constraints.
- There is substantial uncertainty about the rate of load growth these provinces will experience. Greater reliance on all-electric heat pumps could further increase loads, as could development of a hydrogen economy (analyzed in the following scenarios) or other industrial load sectors. Greater long-term load growth, particularly among winter-peaking end-uses, would lead to increased need for offshore wind generation and capacity.
- This study assumes that onshore and offshore wind operate on the same effective load carrying capability (ELCC) curve, with offshore wind given higher capacity credit based on its higher capacity factor. However, initial investigation suggests that this may be a slightly conservative assumption, given initial observation of lower correlation between onshore and offshore resources during the high loss of load probability hours. Work in Phase 2 and Phase 3 will more fully evaluate the capacity value of offshore wind independent of land-based wind. A more robust assessment of the potential for onshore and offshore wind diversity value will also be evaluated and integrated in the next phases of work, once the final offshore wind shapes are developed in Phase 2.

Figure 16. Domestic-only Market Dispatch (MWh), 2035 Winter Day

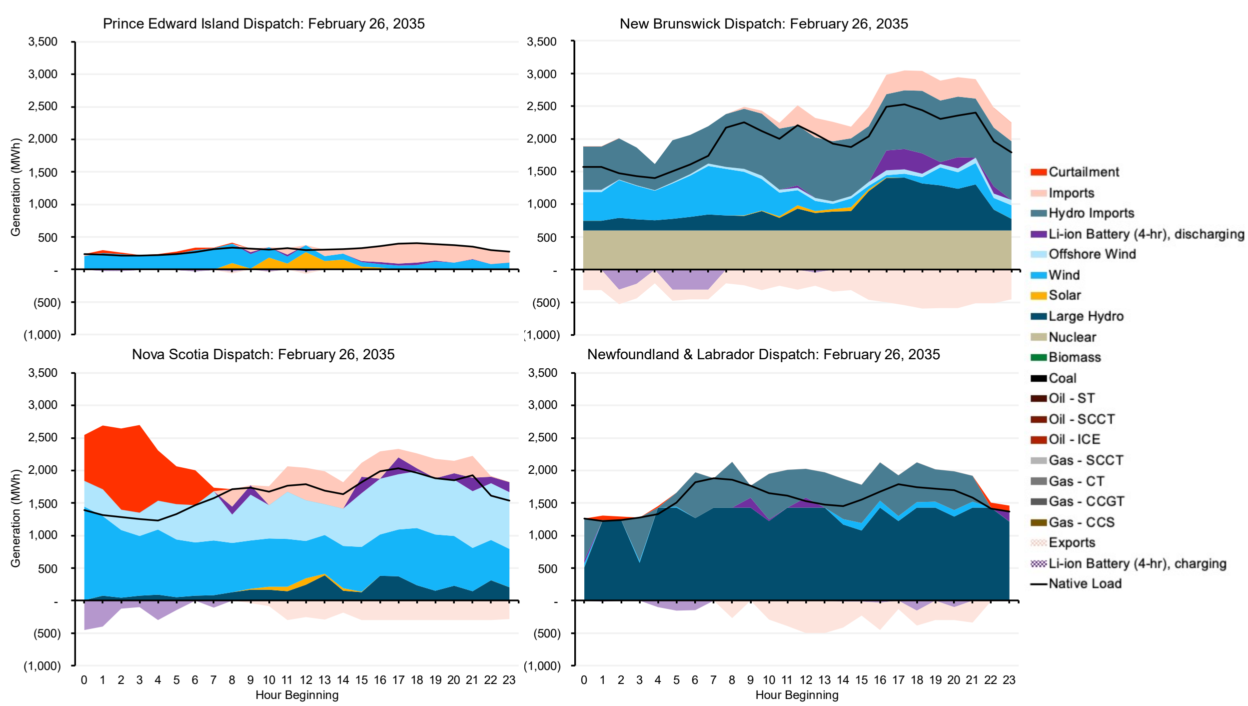
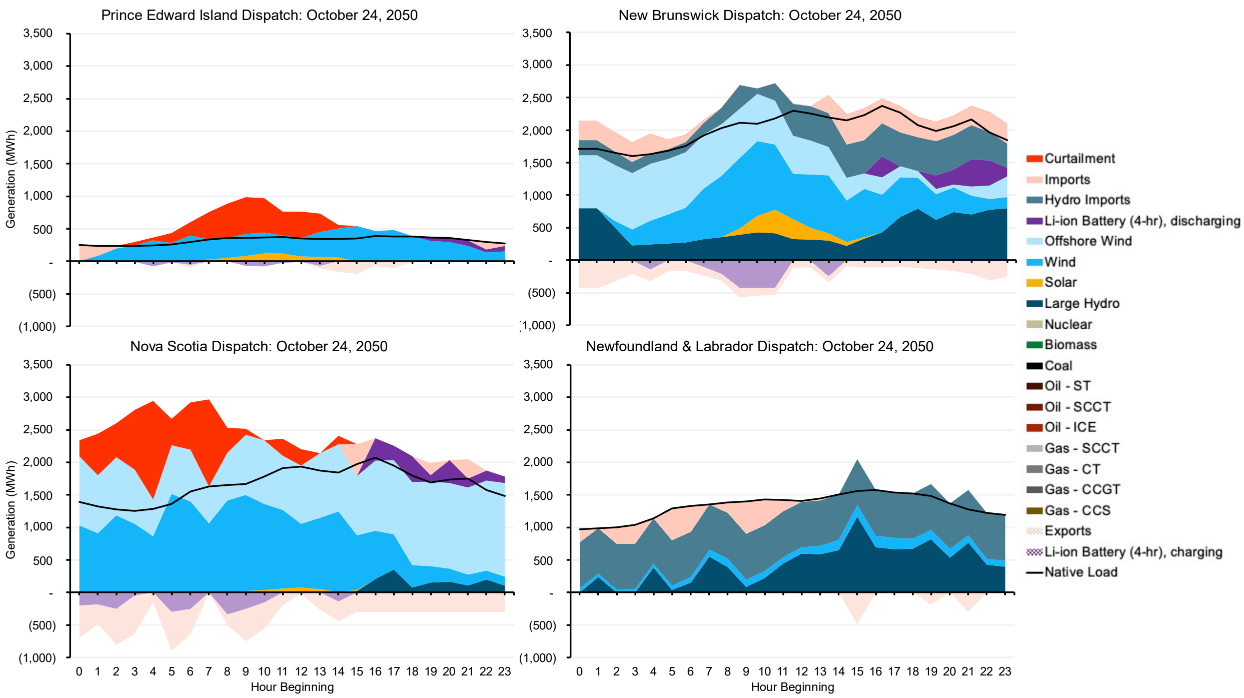


Figure 17. Domestic-only Market Dispatch (MWh), 2050 Fall Day



Market Opportunity to Support Exports

Export markets provide a key additional opportunity for offshore wind in Atlantic Canada. While meeting growing domestic demand can support a more limited industry, access to external markets would enable the region to significantly scale the offshore wind industry, driving greater economies of scale and bringing revenue into the region. Growing regional ties would also facilitate more efficient supply/demand balancing, reduce curtailment, and increase offshore wind utilization.

To explore the role of exports in enabling larger offshore wind buildouts, the study included market transaction opportunities with two neighboring regions: ISO New England (ISO-NE) and Hydro-Québec (HQ). Of the two, ISO-NE represented the larger *modeled* opportunity, with offshore wind capacity matched by expanding transmission between Nova Scotia and ISO-NE—up to 2,000 MW by 2035, 4,000 MW by 2040, and 6,000 MW by 2050. ISO-NE was modeled using a fixed market price curve based on the Boston zone, selected given it represents a large load center and would be most able to absorb high volumes of offshore wind. This structure allowed the model to simulate economically viable export-driven offshore wind development, reflecting realistic price signals from a major U.S. market. Hydro-Québec was also included in the export analysis, though it represented a smaller *modeled* opportunity with its 1 GW transmission limit. In reality, HQ's overall system size and electricity demand are larger than ISO-NE's; however, due to limited data availability and price transparency in the HQ market, it was modeled conservatively.

Market exports occur if the following conditions are met:

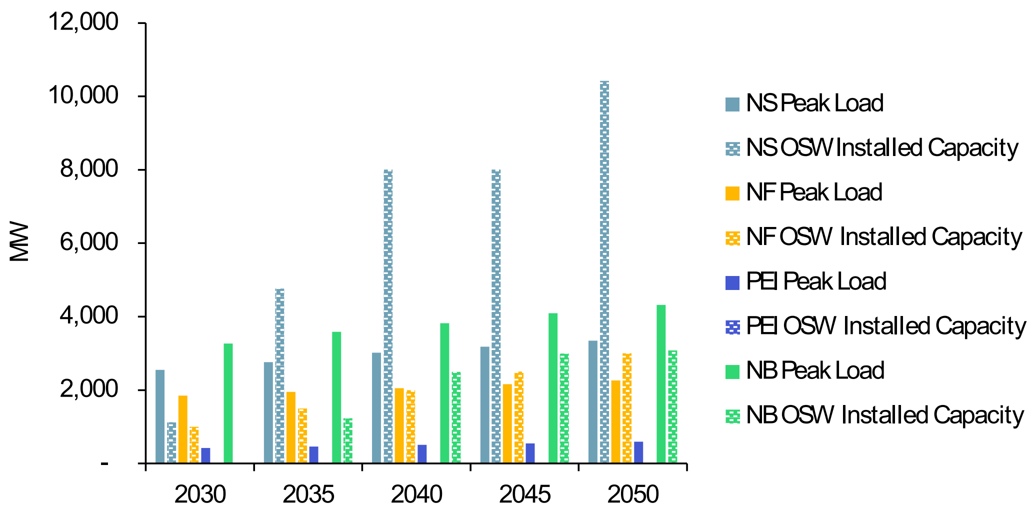
1. There is an excess of offshore wind generation that cannot be used to meet local loads

2. Prices in the external market are high enough for offshore wind exports from Atlantic Canada to be financially viable (e.g. external price exceeds relevant hurdle rates, as discussed below)

The first condition, indicating an opportunity for exports of excess offshore wind generation, can be met for two main reasons. The first is that in some provinces, offshore wind generation exceeds loads. Figure 18 depicts peak loads and installed offshore wind capacity across Atlantic Provinces and indicates an excess of offshore wind relative to loads in Nova Scotia and to a lesser degree in Newfoundland and Labrador. New Brunswick, which has more limited access to offshore wind resources, has sufficient load to self-consume most local offshore wind generation.

The second reason for excess offshore wind generation is inter-provincial transfer limits acting as a barrier to moving excess offshore wind between Atlantic Provinces. In the Phase 1 modeling, this transmission constraint was most apparent between Nova Scotia and New Brunswick, the largest load center. That said, the allocation of offshore wind across provincial locations and the associated implications for transmission are continuing to be studied in Phase 2 and 3.

Figure 18. Provincial Peak Loads and Offshore Wind Installed Capacity in Export Scenarios



Note: The above installed capacity values will be updated based on the finalized resource technical potential values developed in Phase 2.

When there is excess offshore wind within a province that either cannot reach loads in other Atlantic Provinces *or* there is no need in other provinces, it becomes available for export. In the Phase 1 model, Hydro-Québec exports are limited by the transmission capacity between Nova Scotia and New Brunswick; in order to reach Quebec, excess offshore wind in Nova Scotia must first flow into New Brunswick. As a result, the Phase 1 modeling results show very few exports to Hydro-Québec, as illustrated in Figure 23 where annual transmission utilization in the direction of the Hydro-Québec market does not exceed 4% in export cases. Subsequent phases will further investigate this dynamic, by updating wind potentials across provinces and modeling increased intertie cases between provinces.

To consider exports into ISO-NE, the model considers periods in which there is excess offshore wind in the Atlantic Provinces, and evaluates whether hourly market prices create attractive export opportunities.

When prices are high, excess offshore wind may be exported. When prices are too low, that excess generation is curtailed. This curtailment due to uneconomic export conditions can be seen in Figure 12. ISO-NE prices in a given hour[27] must exceed the $5.31 marginal cost of offshore wind exports from the Atlantic Provinces to warrant exporting over curtailing excess generation. The marginal cost of offshore wind exports is comprised of two main parts. The first is a $2/MWh integration charge placed on all renewables in the model, representing the cost to stabilize the grid under deep decarbonization scenarios. The second is a $3.31/MWh wheeling charge placed on all exports meant to encourage local consumption over exports.[28]

Figure 19 through Figure 22 depict how the conditions that enable economic exports to external markets contribute to either economic exports or curtailment. The charts depict month-hour average conditions in a 2040 sample year, for scenarios with exports and hydrogen loads. Figure 19 shows that curtailment of offshore wind occurs during spring and summer midday hours, which coincides with times when ISO-NE market prices are lowest, as illustrated in Figure 20. Similarly, when prices are low and offshore wind generation is being curtailed, Figure 21 shows low utilization of the transmission tie from Nova Scotia to ISO-NE. But when ISO-NE prices are high, curtailment is low and line utilization is near its max. We also see in Figure 22, that in spring and summer midday periods when exports to ISO-NE are not economic, utilization of the Nova Scotia-New Brunswick tie is maxed out. This indicates that the line's maximum transfer capability is limiting excess generation from reaching New Brunswick loads and the Hydro-Québec market.

Based on these results and the underlying dynamics, the regional assessment identified several key enablers for offshore wind deployment to support export markets, including but not limited to:

+ **Lowering costs of offshore wind**: As described above, the cost of offshore wind from the Atlantic Provinces must continue to decrease to compete in U.S. markets. New England states, such as Massachusetts, are actively procuring offshore wind projects to meet their growing energy demands, though this has been largely paused given the Trump administration's executive order to halt new offshore leasing and permitting. To effectively compete with these local resources and generate buy-in from New England ratepayers, the Atlantic Provinces must demonstrate that their higher energy output can offset the additional transmission costs, resulting in a competitive all-in levelized cost of energy or power purchase agreement price. While this presents a significant challenge, many New England planning studies indicate a need for over 30 GW of offshore wind capacity. This suggests that Atlantic Provinces offshore wind could secure a place on the supply curve by offering competitive pricing or by demonstrating greater feasibility compared to certain New England-based projects.
+ **Ability to permit and cost effectively build GW-scale new transmission:** Offshore wind will only be valuable if it can be transported to demand sources to the south (e.g. New England or New

[27] ISO-NE prices fluctuate hourly, set by the marginal energy resource needed to serve load in a given hour in the New England market. Dispatch and import/export decisions within the model respond to these price signals, optimizing around the least cost fixed and operational portfolio – subject to constraints – in Atlantic Canada.

[28] Note that the cost to develop incremental export capacity between Atlantic Canada and New England has not yet been included in this modeling. If expanded interregional transmission is developed, and if the provinces take on a meaningful portion of that investment and development, then that would impact optimal portfolio findings.

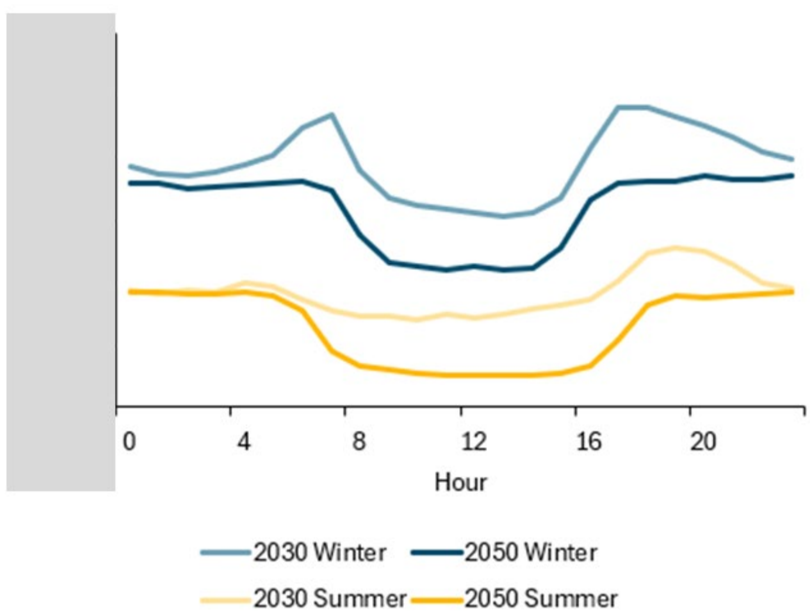
York) or west (e.g. Quebec or Ontario) at low enough costs to be competitive with clean energy alternatives within those regions. Large amounts of transmission are required (GW-scale) to ensure enough offshore wind can be effectively used, and this requires the ability to build transmission. To access New England, this could take the form of subsea HDVC lines, which can be more cost effective over long distances, and may avoid permitting or environmental challenges on land, enable delivery of large quantities of energy, reduce the distance of cable needed, and facilitate lower energy line losses. Offshore wind projects could also demonstrate that they are environmentally preferable, or a better option for New Englanders from a siting perspective. The range of options for transmission connection into New England or other neighboring regions can be further explored in follow-up to this phase.

+ **International alignment and coordination on key aspects of projects:** Developing a cross-border energy project requires collaboration across multiple dimensions, including regulatory alignment, infrastructure development, and market integration. This involves ensuring compliance with diverse energy, environmental, and permitting laws and policies in both countries. Offshore wind projects must also meet the market rules and requirements of ISO-NE to ensure successful participation. Additionally, substantial technical coordination and contingency planning are essential to address risks related to supply obligations, system integration, and potential outages. Commitment to cost-effective pathways to net-zero in both regions may be a valuable springboard to this, but significant coordination will be critical to large-scale international clean energy markets.
+ **Load materializing at scale in other markets:** Offshore wind will only be valuable to New England if load growth materializes in-line with net-zero targets. Today, New England is summer peaking; however, a transition to winter peaking is expected by the early 2030s. This change is driven by the electrification of heating to achieve decarbonization targets, which could more than double the region’s winter peak demand. Such a shift would contribute to periods of greatest resource insufficiency in the winter and make offshore wind significantly more valuable to the region. However, realizing this transition is essential for offshore wind to deliver its full potential value to the region.

Figure 19. All Markets, Season-Hour Average Offshore Wind Curtailment in 2040 (MWh)

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	261	11	27	47	208	140	213	96	-	-	-	184	-	-	-	-	-	-	-	37	99	-	153	-
Spring	575	700	873	607	514	677	2,029	2,107	2,030	1,992	1,678	1,322	1,086	1,272	1,330	1,589	1,327	391	301	392	348	680	944	1,503
Summer	-	50	-	-	41	816	1,312	398	710	407	356	58	19	-	77	92	-	-	-	-	-	-	-	-
Fall	497	908	898	473	235	194	656	1,360	824	928	647	650	468	341	512	-	-	-	41	-	-	-	-	14

*Figure 20. Season-Hour Average Price Shape**



* Note: Y-axis not included given confidential information.

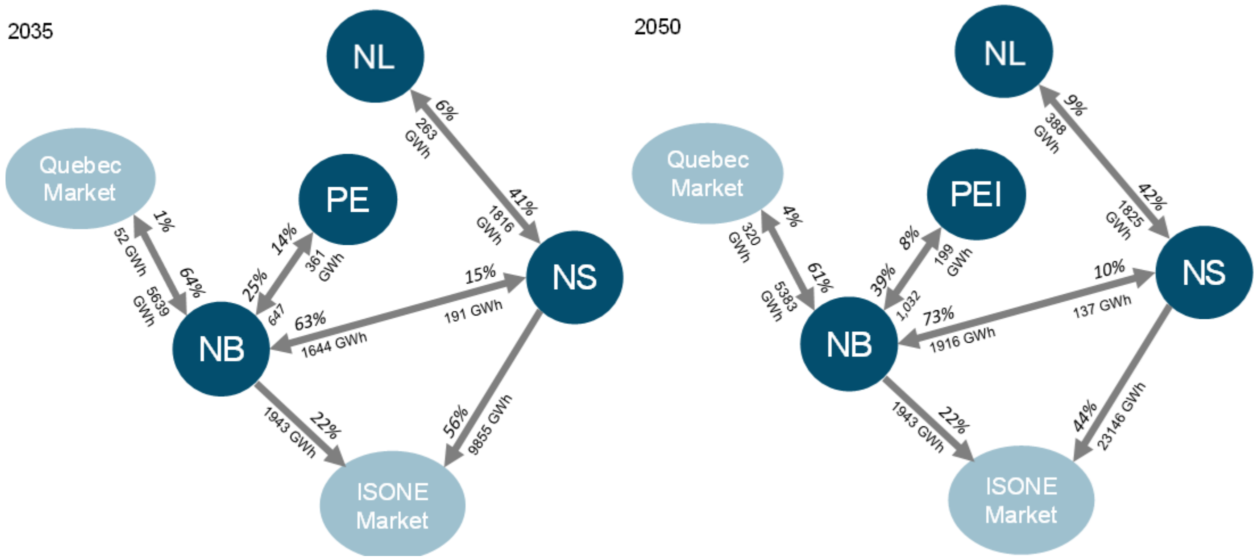
Figure 21. All Markets, Season-Hour Line Utilization from Nova Scotia to ISO-NE in 2040 (%)

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	81%	79%	74%	72%	80%	88%	94%	75%	73%	56%	62%	44%	80%	69%	66%	86%	85%	78%	77%	79%	66%	70%	72%	68%
Spring	61%	62%	49%	65%	68%	61%	11%	7%	0%	3%	2%	3%	2%	0%	7%	12%	25%	72%	76%	88%	81%	73%	60%	47%
Summer	81%	88%	79%	85%	71%	40%	30%	41%	7%	13%	26%	18%	15%	17%	7%	6%	26%	50%	82%	87%	81%	76%	71%	69%
Fall	71%	63%	63%	64%	81%	73%	50%	22%	34%	33%	36%	35%	45%	39%	44%	80%	75%	77%	76%	86%	82%	81%	84%	81%

Figure 22. All Markets, Season-Hour Average Line Utilization from Nova Scotia to New Brunswick in 2040 (%)

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Winter	13%	18%	13%	44%	23%	13%	13%	39%	42%	60%	27%	47%	13%	57%	23%	0%	49%	24%	26%	21%	25%	24%	23%	21%
Spring	20%	20%	35%	26%	28%	36%	50%	63%	69%	63%	83%	82%	69%	72%	69%	70%	68%	44%	35%	18%	8%	26%	26%	14%
Summer	14%	7%	31%	33%	57%	70%	98%	73%	51%	73%	65%	73%	70%	70%	93%	95%	90%	42%	18%	14%	37%	15%	21%	17%
Fall	15%	31%	34%	21%	13%	15%	13%	32%	66%	49%	28%	54%	56%	68%	59%	68%	57%	72%	70%	66%	64%	45%	46%	46%

Figure 23. All Markets Scenario, Line Utilization (%) and Flows (GWh), All Provinces for 2035 and 2050



Note: All Markets scenario includes offshore wind serving domestic loads, exports to New England, and base levels of hydrogen demand.

Market Opportunity to Support Green Hydrogen

The future of Canada's hydrogen industry remains uncertain, as it is still in its early stages and depends on the evolution of both domestic and global demand, as well as the region's ability to produce cost-competitive hydrogen. As noted above, hydrogen is a well-established energy source, and when produced from offshore wind or other renewable resources, it can serve as a zero-carbon fuel in hard-to-decarbonize sectors, including high-temperature industrial applications, heavy duty transportation, maritime industrial uses, and peaking power generation.

Today, enthusiasm is rapidly growing for hydrogen production facilities in the Atlantic Provinces, with new projects announced each year on the order of gigawatts. Hydrogen developers cite the potential for the Atlantic Provinces to become a major hydrogen exporter, particularly to Europe, a region with ambitious decarbonization targets and convenient maritime access. In March 2024, Germany and Canada entered a $600 million dollar agreement to invest in building the infrastructure in Canada required to export hydrogen to Germany.

Offshore wind's potential to scale contributes to its potential to support green hydrogen. With high build potential for onshore and offshore wind resources, along with very high offshore wind capacity factors, the Atlantic Provinces' hydrogen economy could be powered by its valuable clean energy. On the other hand, comprehensive analysis that calculate the cost of hydrogen production in the Atlantic Provinces find that the cost of production, particularly from offshore resources, will need to decrease meaningfully to become competitive on a global scale.

To help inform its assessment of hydrogen's potential, E3 conducted a production cost analysis focused on the Atlantic Provinces using its REMATCH tool, which uses hourly market price and grid emission forecasts to calculate the economic sizing of clean energy resources to electrolyzer capacity, the associated optimal operational strategy, and the subsequent levelized cost of producing hydrogen. These cost results are reported in Appendix B.5 and illustrate that lowering the costs of hydrogen production will be a key challenge in scaling hydrogen in the Atlantic Provinces.

While today, hydrogen loads remain uncertain, the modeling also demonstrated that hydrogen loads have the potential to be very large, if they can both serve domestic end uses and compete globally. While serving potential domestic hydrogen demands with wind resources might require on the order of 2 GW offshore wind in 2035 to 4 GW offshore wind in 2050, serving much larger export markets with hydrogen could make the development of hydrogen not limited as much by the amount of offtake, but simply by how much land, storage, and other infrastructure can be built out in the region.

Broadly, select key enablers to build out a robust hydrogen industry in the Atlantic Provinces include:

+ **Policy and government support to drive domestic utilization of hydrogen**. As described in the modeling assumptions, the Atlantic Provinces could use hydrogen to decarbonize hard-to-abate emitting industries like higher-temperature industrial processes, natural gas replacement in peaking power plants, heavy duty trucking, aviation, and other end uses like oil and gas refining. However, regulatory and financial support will be critical to creating market and regulatory frameworks, reducing costs, and ensuring safety if and as the industry scales. Credible government policy signals can also help attract private capital to investment in production of hydrogen.
+ **Reduction in costs across all aspects of hydrogen production from offshore wind.** Lowering the costs along the entire hydrogen and offshore wind supply chain is critical to help this nascent industry scale. While global electrolyzer deployment will help reduce capital costs, strategic siting of hydrogen projects near the clean energy resource, in this case offshore wind, ris also very important. The study modeling showed significant curtailment in hydrogen scenarios in which even a small portion of the hydrogen was produced in a different province than its renewable source, given the thin transmission connections across provinces. This underscores the importance of co-locating demand and production to minimize curtailment and maximize wind utilization.[29] Siting close to offshore wind also reduces overall transmission needs and costs. Siting at or near underground storage, typically the cheapest storage option, enables higher seasonal hydrogen production and delivery to demand centers.
+ **Building out the hydrogen supply chain**. A robust supply chain (e.g., production, transportation, storage) will be needed to support both domestic and international markets, with a particular focus on safe and cost-effective transportation methods. Innovations in hydrogen shipping, including advancements in compression and liquefaction technologies, will be critical for serving international export markets. However, evaluating the costs and logistics of transporting hydrogen over long distances, whether as liquefied hydrogen or ammonia, introduces significant

[29] In Phase 2, E3 will further adjust the locations of hydrogen loads (i.e., assumed production locations) to match where the best wind is built. In Phase 1, hydrogen production and therefore demand was spread somewhat more evenly across provinces.

additional uncertainty and new complexity to serving export markets that have yet to be fully developed at scale.

- **Durable international policy and secure offtake contracts to reduce production risks.** While the Atlantic Provinces have abundant renewable resources, securing offtake for hydrogen is critical to lowering the risk of hydrogen production and getting early projects built. One prerequisite is for international countries to have long-term, enforceable policies that require or incentivize hydrogen, which will drive investor confidence and enable investment. International buyers also need to ensure steady revenues to projects, to mitigate risk and exposure to uncertain and not-yet-existing global markets. Given the highly capital-intensive nature of hydrogen projects and the evolving global hydrogen economy, policy and/or market stability and a secure offtake agreement are needed to drive investments.
- **Demonstrated successful and operational commercial projects.** Hydrogen projects will remain uncertain in terms of safety, feasibility, and cost until commercial-scale projects are successfully developed and operationalized, with supporting infrastructure. These factors make it difficult to predict with certainty the long-term viability of this industry. This uncertainty is not unique to the Atlantic Provinces and is evolving quickly as an increasing number of projects reach the late stages of development. These early commercial projects, particularly those in North America, will be critical to demonstrate feasibility, reduce risks, and drive down costs through learning-by-doing.

Given the current limited number of commercial operational hydrogen projects, the offtake potential for hydrogen produced in the Atlantic Provinces is still developing. Regional demand for hydrogen has not yet materialized, and global demand for clean hydrogen remains in its early stages, with supply chains, regulatory frameworks, and market signals still emerging. Additionally, competition from other regions with lower labor and material costs and closer access to major European markets may influence the competitiveness of Atlantic Canada’s hydrogen exports.

Implications for Phase 2

This Phase 1 report focuses on evaluating the long-term electricity needs and opportunities across the Atlantic Provinces, drawing on publicly available data from utilities, provincial energy plans, and federal policy as of October 2024. The study incorporates regional outlooks and input from the provincial and utility advisory committees to develop scenario-based offshore wind planning targets aligned with potential sources of future demand—including domestic electrification load, electricity exports, and hydrogen production needs.

These offshore wind build-out scenarios were integrated into a broader modeling assessment of the regional electricity system to explore how offshore wind affects the rest of the regional electric grid needs, using a capacity expansion framework. This approach considers a range of factors, including other potential candidate resources, operational performance, policy goals, transmission constraints, and system reliability. The framework resulted in an in-depth understanding of the potential impacts of offshore wind on system costs, emissions, and energy reliability. The analysis shows that between 2 GW and over 16 GW of offshore wind could be developed, depending on market opportunities—particularly the future scale of the hydrogen sector, which remains early-stage and developing. While under current cost and resource performance assumptions, modeled offshore wind scenarios come at a higher cost compared to a least-cost scenario without offshore wind, these findings illustrate that cost reductions coupled with targeted policy and coordinated infrastructure could help the region to realize offshore wind's potential and benefit from its clean energy contributions.

The subsequent phases of this study will refine and expand on this market assessment. Phase 2 will build on the resource assessment work from Phase 1 by refining key inputs and conducting more granular operational modeling to understand how offshore wind impacts pricing and dispatch within the provinces. The following key updates will be incorporated into the final roadmap:

1. **Updated offshore wind capacity estimates** for both fixed and floating resources. This will be a valuable refresh of our understanding of offshore wind potential across all provinces, with particular refinement of the resource representation in NB, PEI, and NL, since less detailed offshore wind information is currently available for these provinces relative to NS.
    a. This will include an Economic Potential assessment in addition to technical and locational potential for each build site. As part of the Economic Potential analysis, Stantec will develop AACE Class 5 level cost estimates for all potential resource builds and the associated transmission development needed to deliver those to coastal POIs. This detailed cost evaluation will be extremely valuable for the continued evaluation of the economics of offshore wind in the Atlantic Provinces
2. **Updated generation profiles for each offshore wind site**. Similar to the capacity potential refinement, this will enhance the detailed operational modeling of generation potential, better capture correlation between sites and with load centers, and identify onshore grid impacts, particularly in the provinces where currently available data is less detailed.

These updates will be incorporated into hourly production cost simulation modeling, which will be conducted in PLEXOS ST. Through that analysis, our teams will work to build on key learnings from Phase 1, including:

1. How much offshore wind generation can be absorbed by load in the Atlantic Provinces? How much might get curtailed, under what circumstances, and how does that impact offshore wind resource economics? What development and transmission strategies can reduce curtailment to improve the economics of offshore wind? How big of an impact are existing onshore transmission constraints having on offshore wind generation delivery?
2. How much market demand do we expect New England, and/or Quebec and Ontario, to have for offshore wind imported from Atlantic Canada? What are the economic implications of those exports?
3. How might an emerging hydrogen economy impact offshore wind resource development? What are the operational synergies and challenges of these development priorities?
4. How does the presence of offshore wind impact prices in the Atlantic Provinces? How does it change dispatch and economics for the existing generation fleet?

Appendix A. Additional Detailed Results

The following presents selected additional results from the Phase 1 modeling. In the final Roadmap, more detailed modeling outputs—grounded in the updated offshore wind characterization developed in Phase 2—will be released. These will include data tables for selected key outputs, which will be made available through a public database.

A.1. Province Specific Findings

New Brunswick

New Brunswick, as the largest energy load center among the Atlantic Provinces and a hub for regional interconnectivity, exhibits distinct dynamics in electricity generation and installed capacity under varying scenarios aimed at achieving Canada's decarbonization targets. In Figure 24 and Figure 25, E3 shows a summary of New Brunswick modeling results for generation and installed capacity, respectively.

In modeled scenarios, wind emerges as a critical driver for decarbonization, with offshore wind capacity and generation bolstering growing onshore wind significantly over time. By 2050, scenarios illustrate potential futures in which offshore wind supports domestic electricity demand, facilitates export opportunities, and enables the development of a nascent hydrogen economy. The high-capacity factors of offshore wind, particularly during winter peak periods, make it a robust resource for addressing growing electrification loads and the retirement of fossil-fueled capacity.

Total installed capacity in New Brunswick increases markedly across scenarios to accommodate rising electricity demands. This, combined with generation dynamics, reflect a shift from fossil fuels toward renewables and imports. While traditional fossil-based generation like coal and gas diminishes across scenarios, onshore wind, offshore wind and imports from Nova Scotia, HQ, and Prince Edward Island, play pivotal roles. Imports help balance regional supply-demand dynamics and enable efficient integration of offshore wind.

New Brunswick's energy landscape under these scenarios highlights the critical role of offshore wind, regional flows, and infrastructure development in achieving ambitious decarbonization targets while meeting growing electricity and hydrogen demands.

Figure 24. New Brunswick Generation (GWh) Across All Scenarios

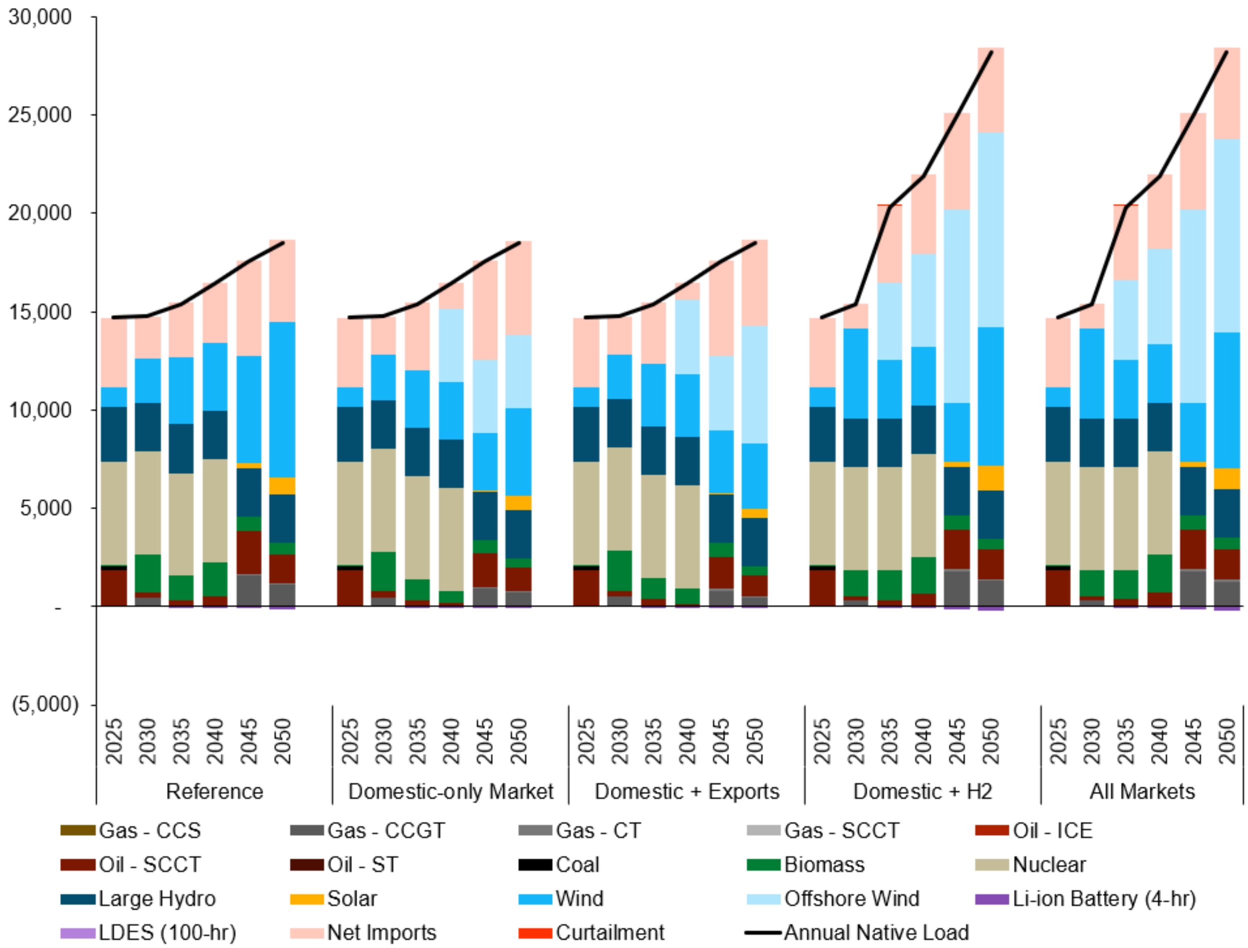
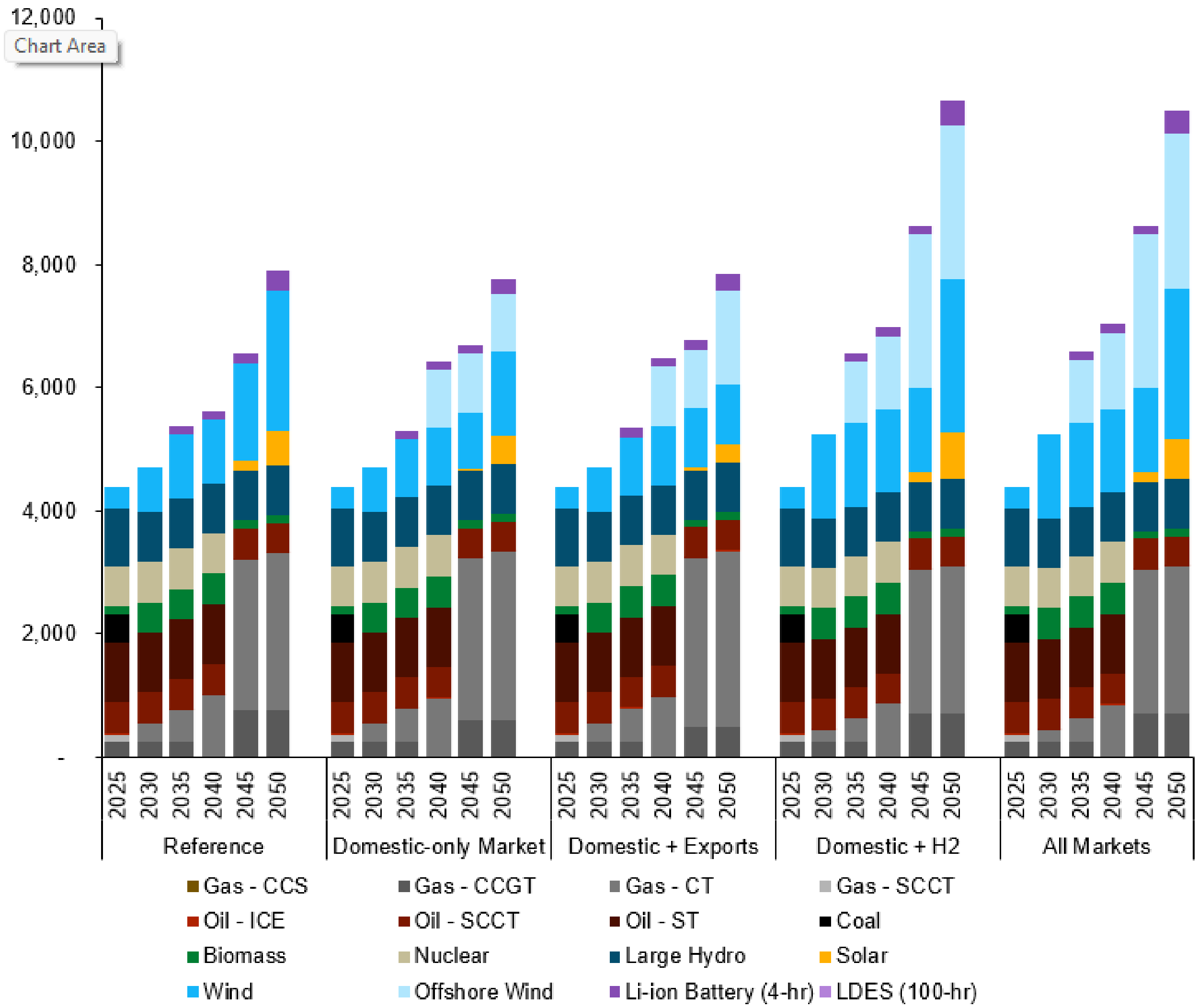


Figure 25. New Brunswick Installed Capacity (MW) Across All Scenarios



Nova Scotia

Nova Scotia's energy generation and capacity evolve significantly under the modeled scenarios to explore pathways to decarbonization, emphasizing offshore wind integration, increased exports, and hydrogen production. Figure 26 shows the generation in Nova Scotia and Figure 27 shows the installed capacity in Nova Scotia for select model years across all scenarios. These results of the modeled scenarios highlight the potential of offshore wind in meeting domestic demand and participating in export markets while supporting net-zero goals.

Offshore wind is a central component of decarbonization efforts, with substantial capacity additions modeled in non-reference scenarios. By 2050, offshore wind capacity exceeds 6 GW in scenarios prioritizing hydrogen and export markets. offshore wind generation scales to meet increasing domestic demand, including peak winter loads, and provides a high-quality, zero-emissions resource for export markets, particularly ISO-NE.

Offshore wind also supports hydrogen production in the Domestic + H2 and All Markets scenarios, driving a significant portion of energy demand by mid-century. By 2050, a significant portion of the hydrogen load is met through offshore wind, reflecting its potential as a decarbonization pathway for heavy industry and transportation sectors.

Curtailment of renewable resources emerges as a challenge during high-output periods, reflecting the need for enhanced storage, grid balancing, and increased inter-regional transmission capacity. Under the modeled scenarios, Nova Scotia emerges as a significant exporter of clean electricity, driven by its high-quality offshore wind resources. By 2050, significant offshore wind capacity supports exports primarily to New Brunswick and the ISO-NE market. Offshore wind's seasonal stability, with high winter capacity factors, aligns well with peak demand in New England and complements New Brunswick's existing generation mix. The potential for enhanced transmission infrastructure between Nova Scotia, New Brunswick, and ISO-NE could enable further export growth, addressing transmission congestion and curtailment challenges.

Installed capacity diversifies significantly, with substantial growth in offshore wind, battery storage and other renewables by 2050. Fossil fuel capacity decreases, driven by retirements and emissions reduction goals, with remaining gas generation serving as a peaking resource.

The analysis underscores the valuable role offshore wind could play in decarbonizing Nova Scotia's electricity system, fostering export opportunities, and supporting emerging hydrogen industries, while highlighting the challenges of cost, infrastructure, and system integration.

Figure 26. Nova Scotia Generation (GWh) Across All Scenarios

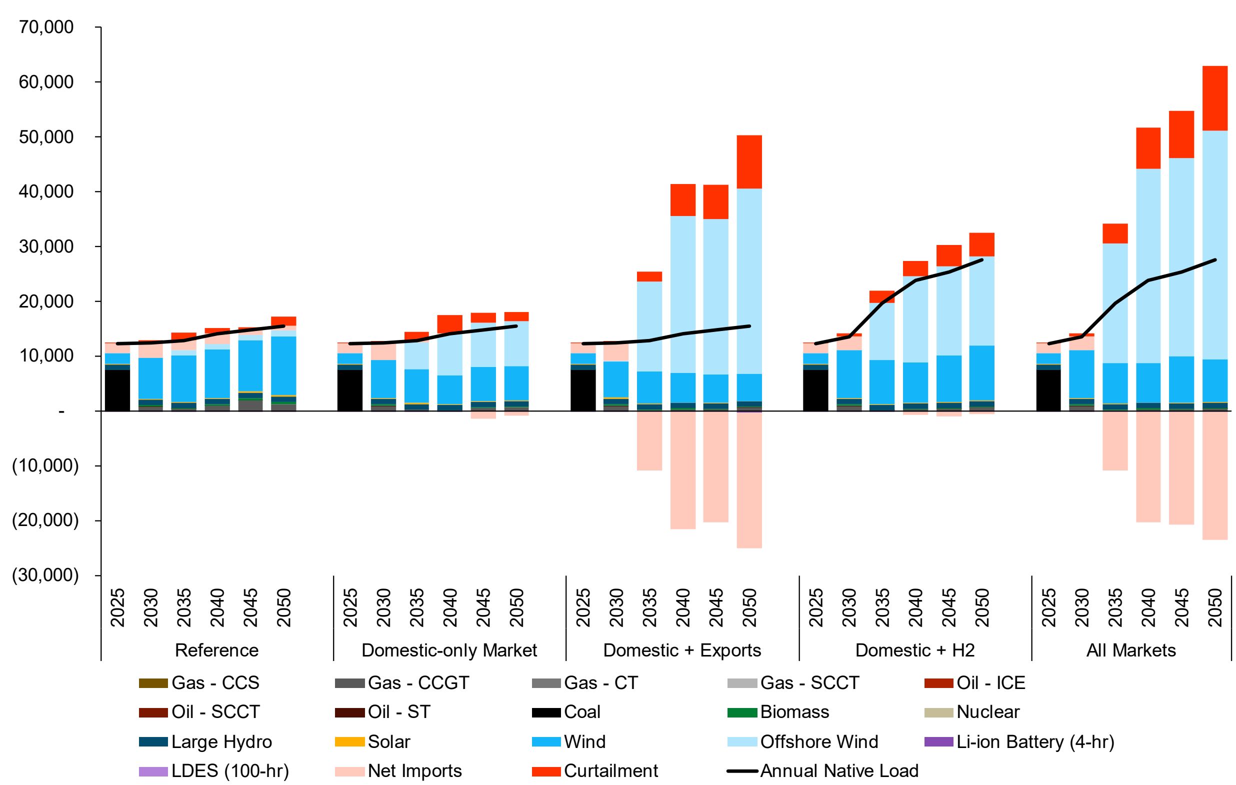
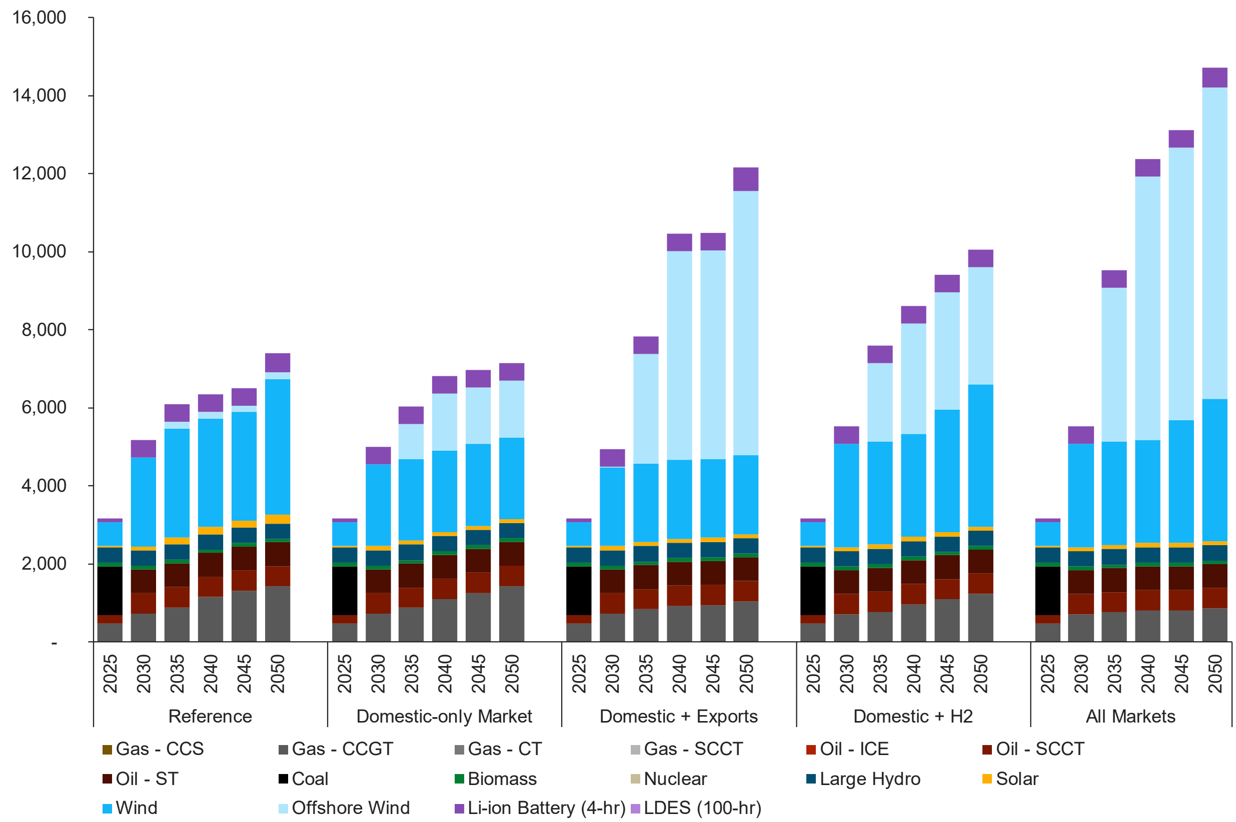


Figure 27. Nova Scotia Installed Capacity (MW) Across All Scenarios



Newfoundland & Labrador

Newfoundland & Labrador (NL), modeled with a focus on its island system of Newfoundland, exhibits a unique energy transition influenced by the abundant hydro resources modeled in Labrador that can be partially accessed by the island system through the Labrador-Island Link (LIL). The combined generation across the province is shown in Figure 28 and the installed capacity is shown in Figure 29.

Newfoundland's electricity generation remains heavily dominated by hydro resources across all scenarios. The LIL enables Labrador's extensive hydro capacity from Muskrat Falls and Churchill Falls to support both the Island's and broader province’s energy needs and export opportunities. Fossil fuel generation, including oil and gas, plays a limited role in the generation mix, consistent with decarbonization goals and the availability of clean hydroelectric power. Offshore wind contributes modestly to generation in later years of modeled scenarios. Offshore wind capacity grows primarily to serve domestic load growth and augment exports to regional markets.

NL's Hydro surplus and emerging offshore wind capacity enable it to act as a net exporter of clean energy to neighboring regions. The presence of substantial hydro capacity, combined with transmission limits described above, result in some curtailment in high-renewable scenarios.

Newfoundland & Labrador's energy system dynamics are shaped by its hydro dominance, the critical role of the Labrador-Island Link, and emerging contributions from offshore wind.

Figure 28. Newfoundland & Labrador Generation (GWh) Across All Scenarios

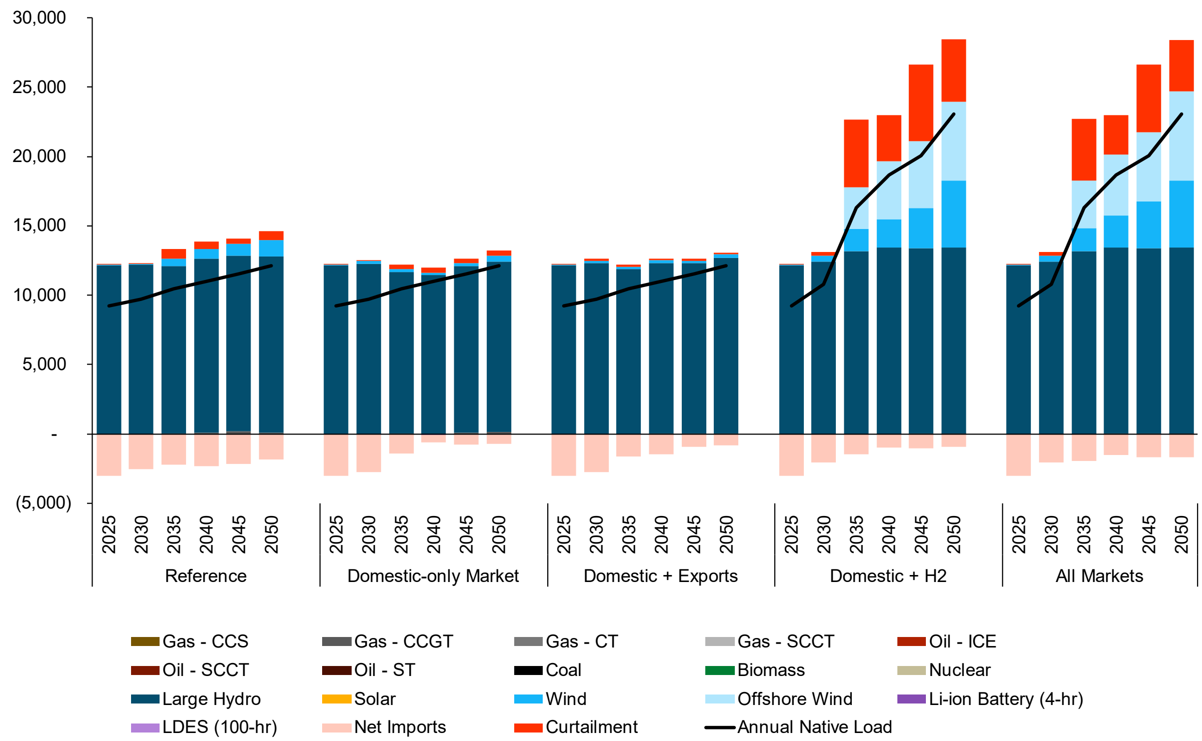
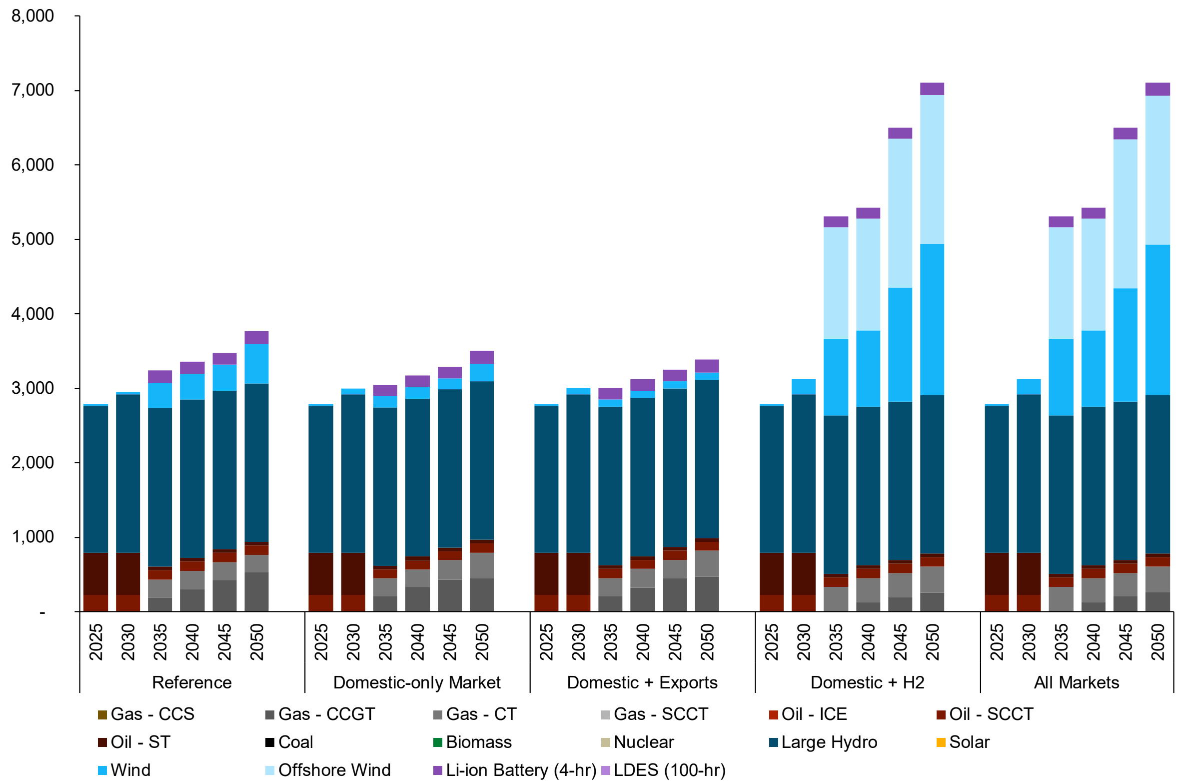


Figure 29. Newfoundland & Labrador Installed Capacity (MW) Across All Scenarios



Prince Edward Island

Prince Edward Island (PEI), with the smallest electricity load among the Atlantic Provinces, demonstrates unique energy system dynamics driven by its reliance on imports and renewable generation. Results for generation and installed capacity in Prince Edward Island are shown in Figure 30 and Figure 31, respectively.

PEI's domestic electricity generation remains relatively small across scenarios, with significant reliance on imported electricity to meet local demand. This dynamic persists even as renewable generation increases in later years. Offshore wind does not play as prominent of a role in the local generation or installed capacity of PEI, but a lot of generation is imported from New Brunswick. Capacity expansion in PEI is primarily geared toward onshore wind. The island's heavy dependence on imports underscores the importance of its interconnection with New Brunswick. These imports complement local renewable generation, particularly during periods of low wind output. Fossil-fuel-based capacity remains negligible in PEI's scenarios, reflecting the province's renewable energy focus and limited domestic demand. Increased renewable capacity leads to instances of curtailment, particularly in high-generation scenarios. This highlights the importance of transmission and storage solutions to optimize resource use.

Prince Edward Island's energy transition emphasizes renewable energy development, especially wind, and relies heavily on imports and regional collaboration to meet demand and integrate clean energy resources.

Figure 30. Prince Edward Island Generation (GWh) Across All Scenarios

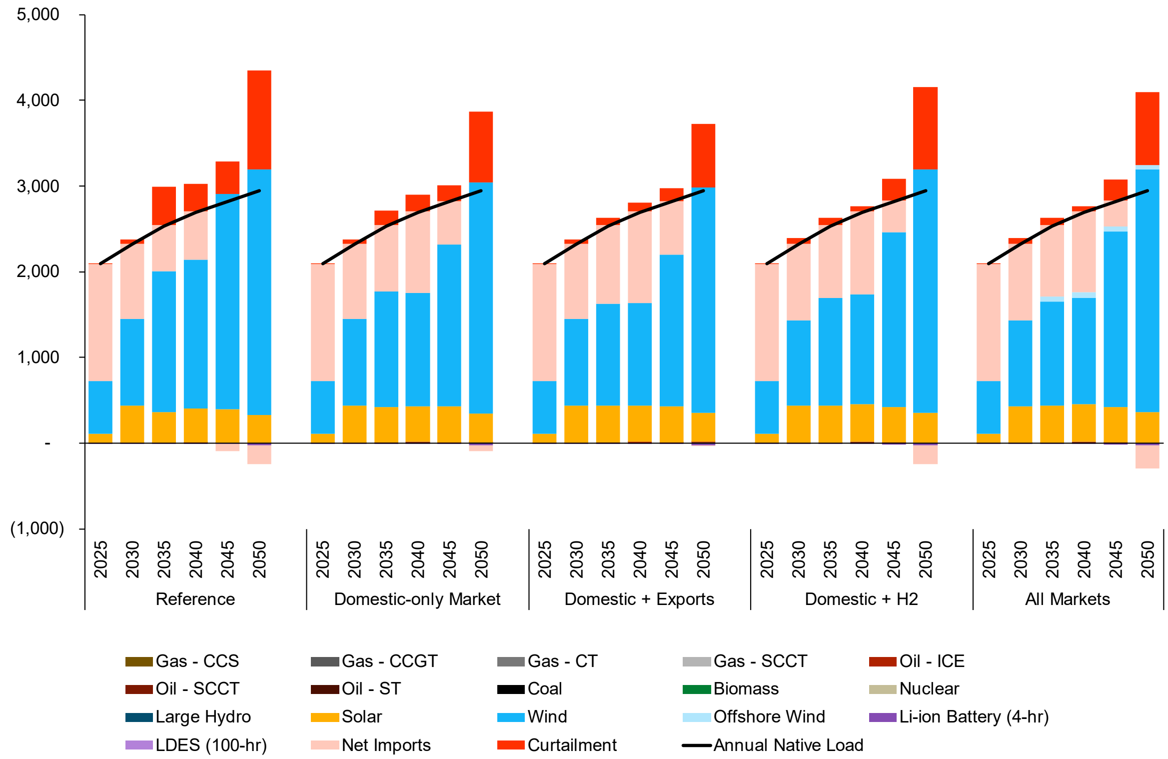
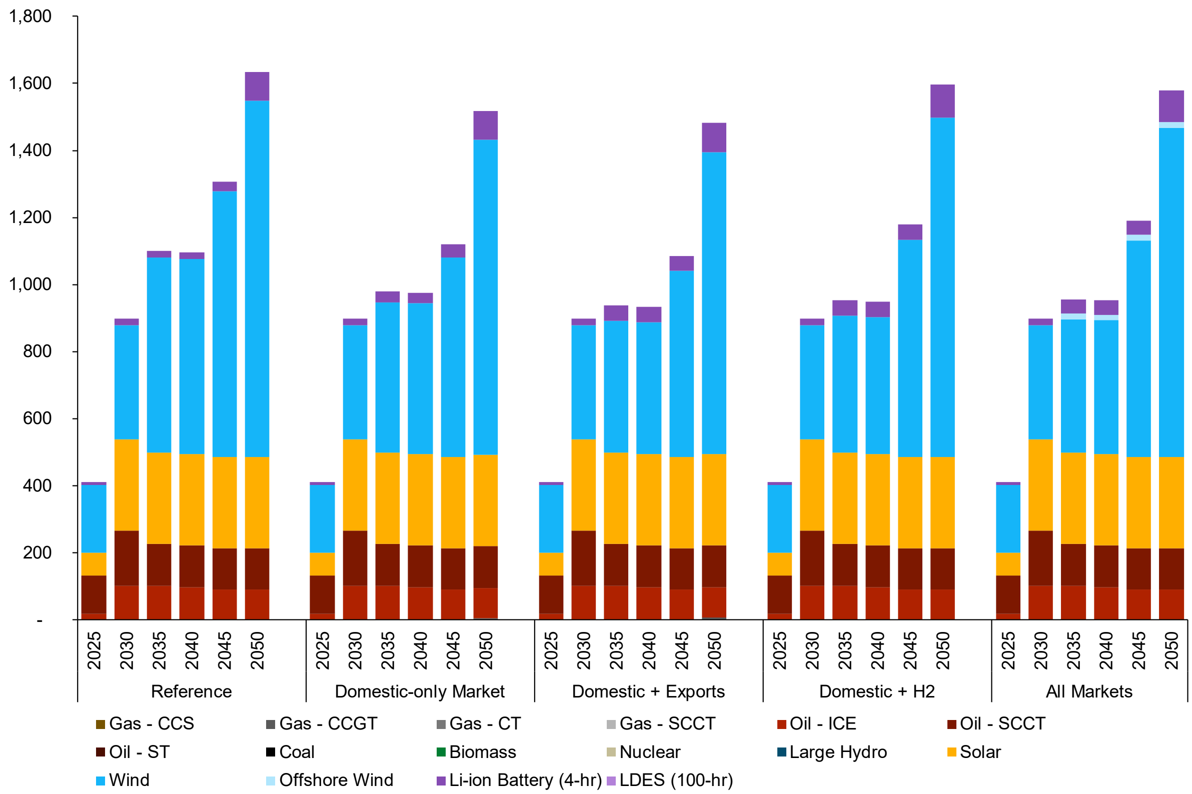


Figure 31. Prince Edward Island Installed Capacity (MW) Across All Scenarios



A.2. Resource Builds and Generation for Sensitivity Scenarios

High Hydrogen Scenario

Hydrogen is a developing zero-carbon alternative, with uncertainty about the magnitude of impact it will have in the Atlantic Provinces. To capture a broader range of possibilities, E3 modeled a sensitivity of the hydrogen scenarios with a higher hydrogen load and greater offshore wind penetration to support these loads. In Figure 32 and Figure 33, E3 reports the total installed capacity and annual generation, respectively, between the base and high hydrogen scenarios. In the high hydrogen sensitivities, there is a higher load and wind deployment, and also higher curtailment. Curtailment occurs in hours when either generation exceeds loads, or transmission capacity between generators and load areas is insufficient for economic power delivery. Phase 1 models only the existing transmission linkages between Provinces, future analysis will further explore the potential to expand these linkages, which may help alleviate curtailment during the most constrained hours.

Figure 32. Total Installed Capacity (MW), Base vs. High Hydrogen Scenarios

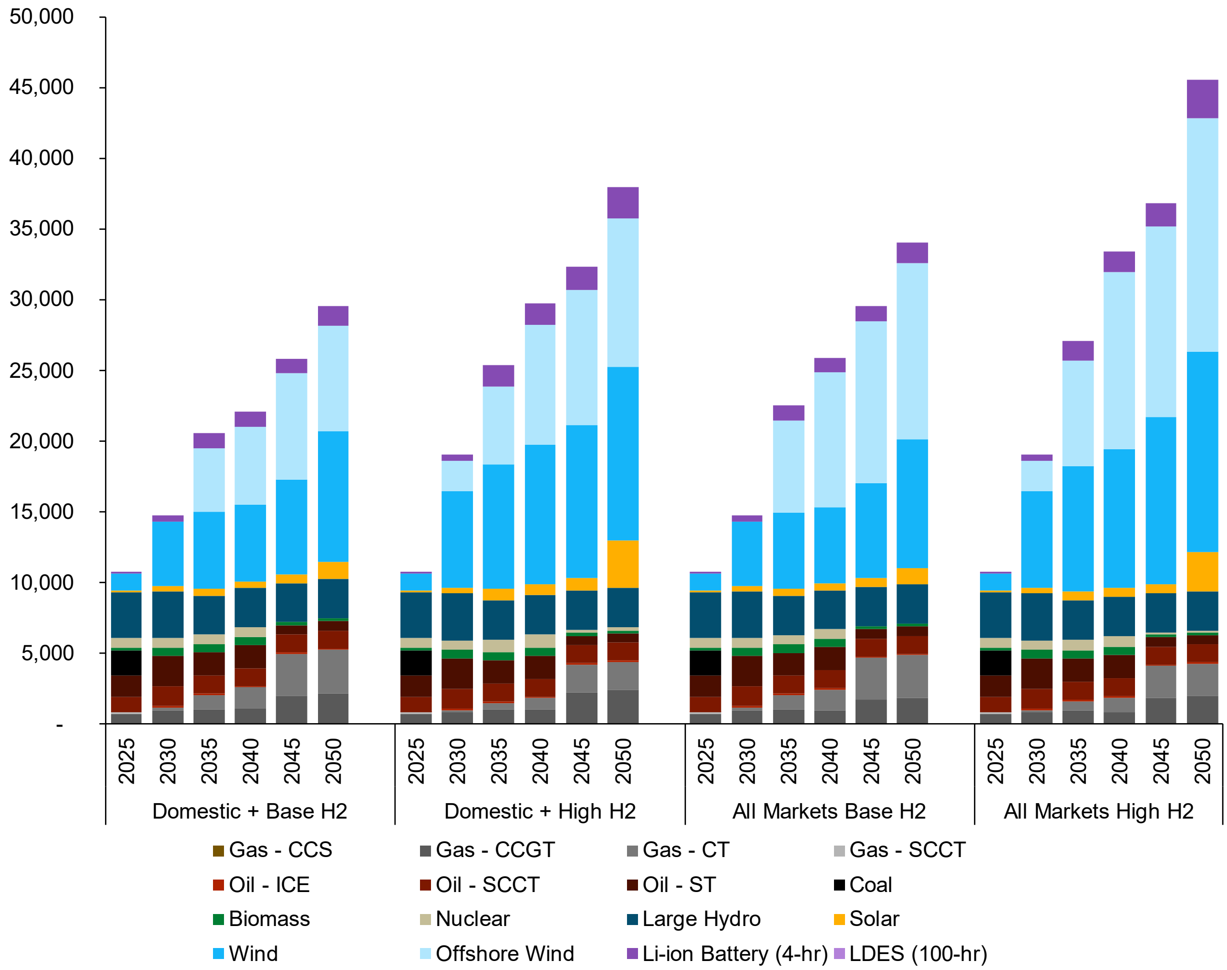
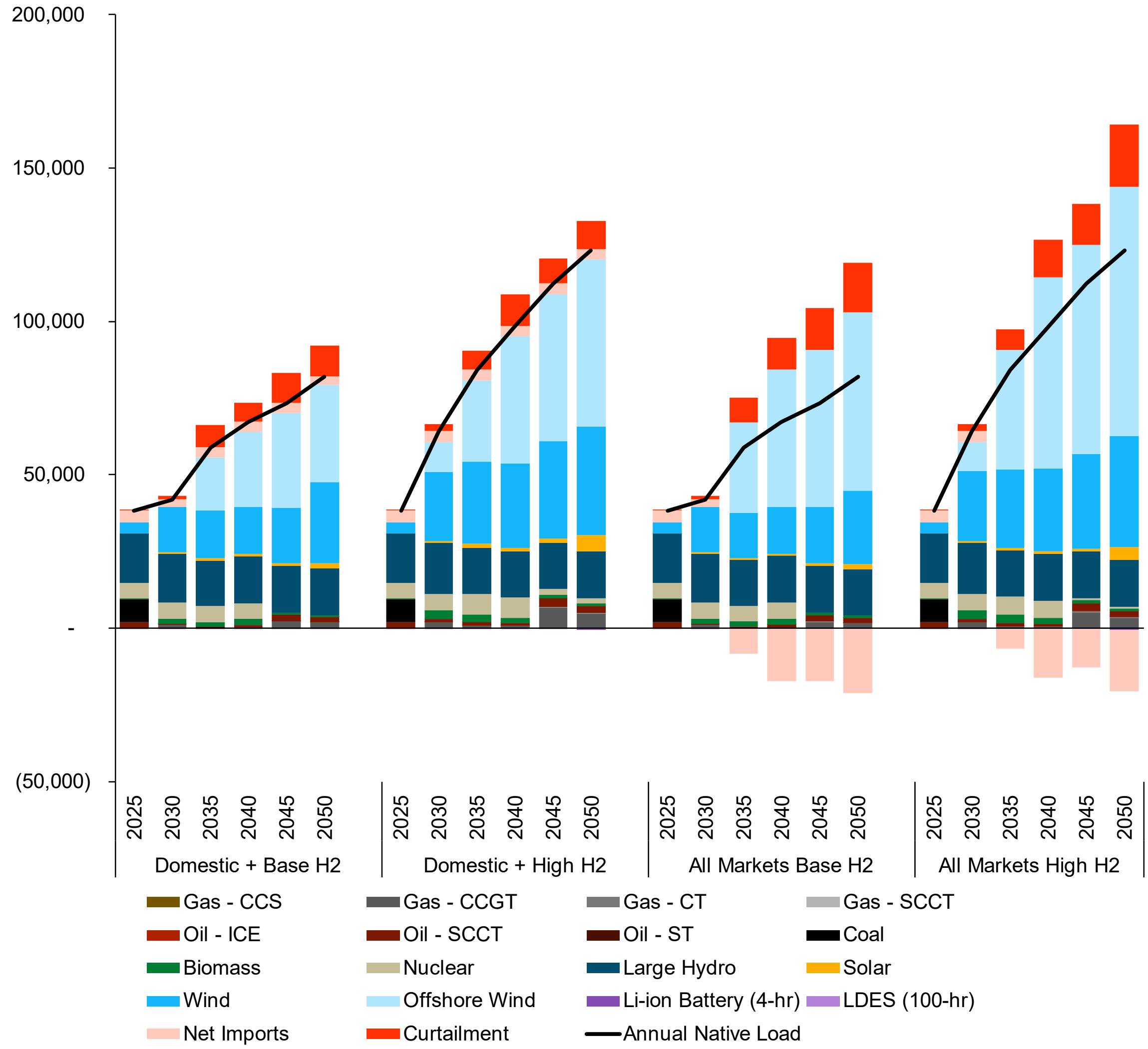
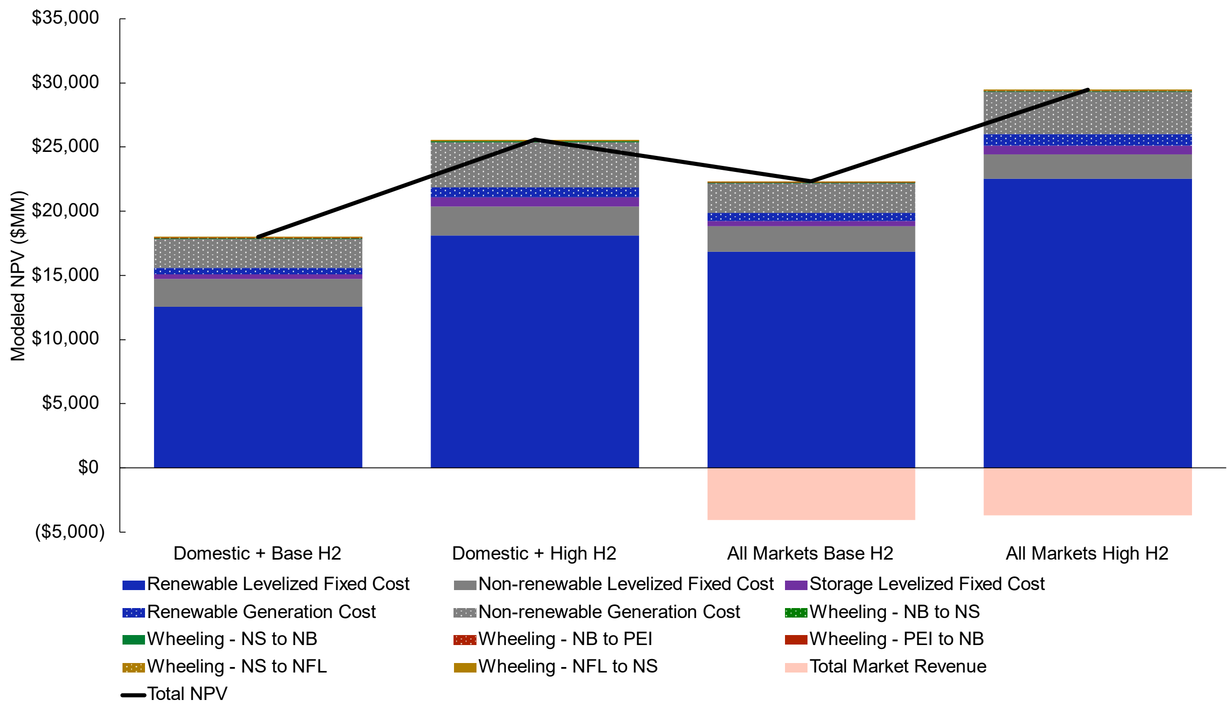


Figure 33. Annual Generation (GWh), Base vs. High Hydrogen Scenarios



When considering the impacts of an expanded hydrogen future in the Atlantic Provinces, it is also helpful to look at the anticipated effects on costs. In Figure 34, E3 shows the modeled NPV and annual cost of energy for all provinces for the base and high hydrogen sensitivities of the Domestic + H2 and All Markets scenarios. In both the Domestic + H2 and All Markets scenarios, the high hydrogen sensitivity has a higher NPV and a higher annual cost of energy ($/kwh) than the base hydrogen sensitivity, as expected. This increase in cost is due to the added capital expenses of incrementally more expensive wind, given current technology and market maturity.

Figure 34. Modeled Cost Comparison, NPV ($MM) Base vs. High Hydrogen Scenarios



Expanded Transmission Scenario

In this study, limited transmission capacity emerged as a key inhibitor to fully utilizing offshore wind build-out and increasing market revenues. To address this, E3 explored a scenario, building off the All Markets (Base Hydrogen) Scenario, with an additional 500 MW of bi-directional transmission capacity between Nova Scotia and New Brunswick, starting in 2035. This is a conservative addition, given that curtailment levels would suggest that at high levels of offshore wind, GW-scale transmission expansion would be important, assuming that new load is not all in Nova Scotia.

The additional transmission capacity had minimal impact on installed capacity, as shown in Figure 35. However, there were notable effects on generation, costs, and line flow/utilization. Figure 36 illustrates the differences in generation between scenarios with and without added transmission capacity. The expanded capacity enables offshore wind generation in Nova Scotia to flow more freely to New Brunswick, a major load center. This reduces curtailment but leaves less energy available for export markets. In future phases of this study, the E3 and Stantec teams will further explore transmission expansion between provinces.

Without additional transmission, 1,593 GWh of energy flows from Nova Scotia to New Brunswick, while 24 TWh is sold to ISO-NE. With the added capacity, over 4 TWh flows to New Brunswick (a 171% increase), while exports to ISO-NE decrease slightly to 23 TWh (a 4% reduction). Figure 37 highlights these changes in line utilization and energy flows for 2035 and 2050.

Figure 38 and Figure 39 detail curtailment patterns and month-hour average line utilization for 2050. Curtailment and line utilization fluctuate in similar patterns, regardless of added transmission. However, curtailment decreases across nearly all time periods when NS-NB transmission capacity is expanded. The NS-NB transmission line is not always fully utilized during curtailment events due to maxed-out transmission to ISO-NE, lack of load to serve, or unfavorable market conditions for selling to HQ.

Expanding transmission capacity between Nova Scotia and New Brunswick, along with improved export market conditions to HQ, is essential for minimizing offshore wind curtailment in the Atlantic provinces. These enhancements allow for more efficient energy flow, reducing bottlenecks and optimizing market revenues.

Figure 35. Total Installed Capacity (GW), With and Without Additional Transmission Capacity, Shown Below for All Markets with Base Hydrogen Scenario

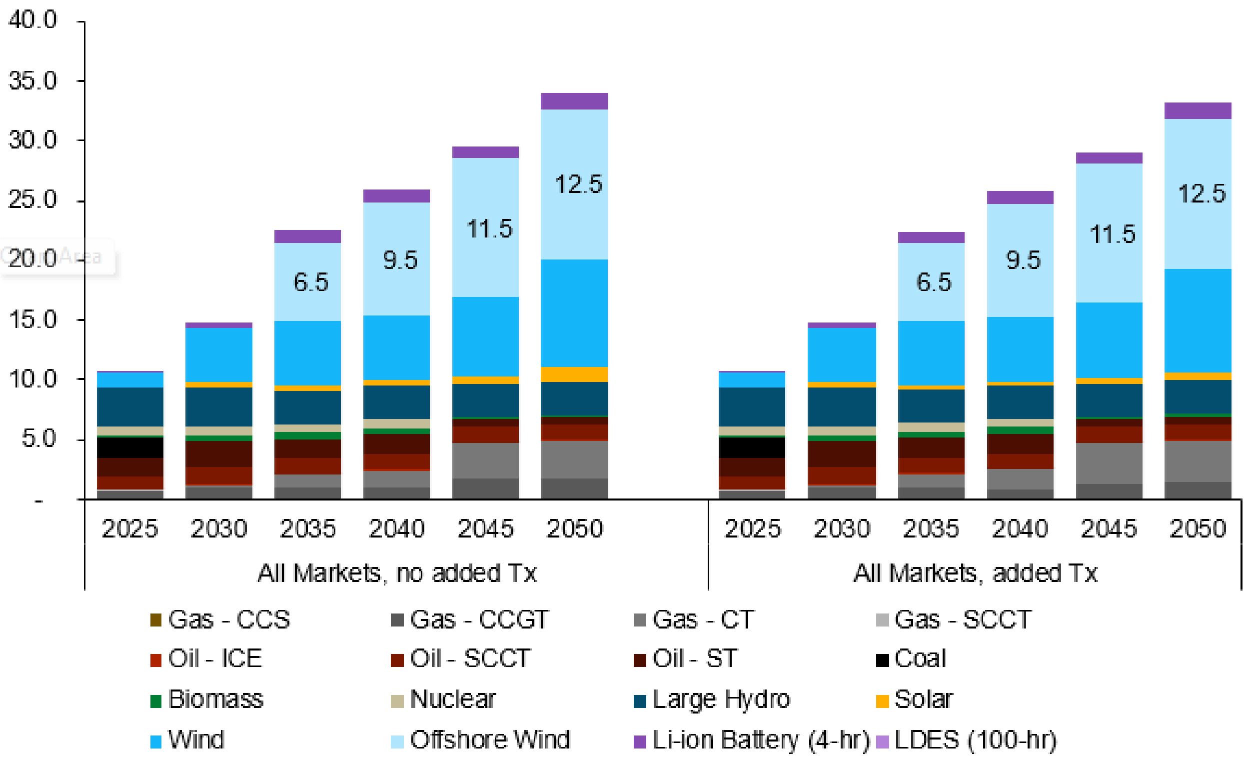


Figure 36. Annual Generation (GWh), With and Without Additional Tx Capacity

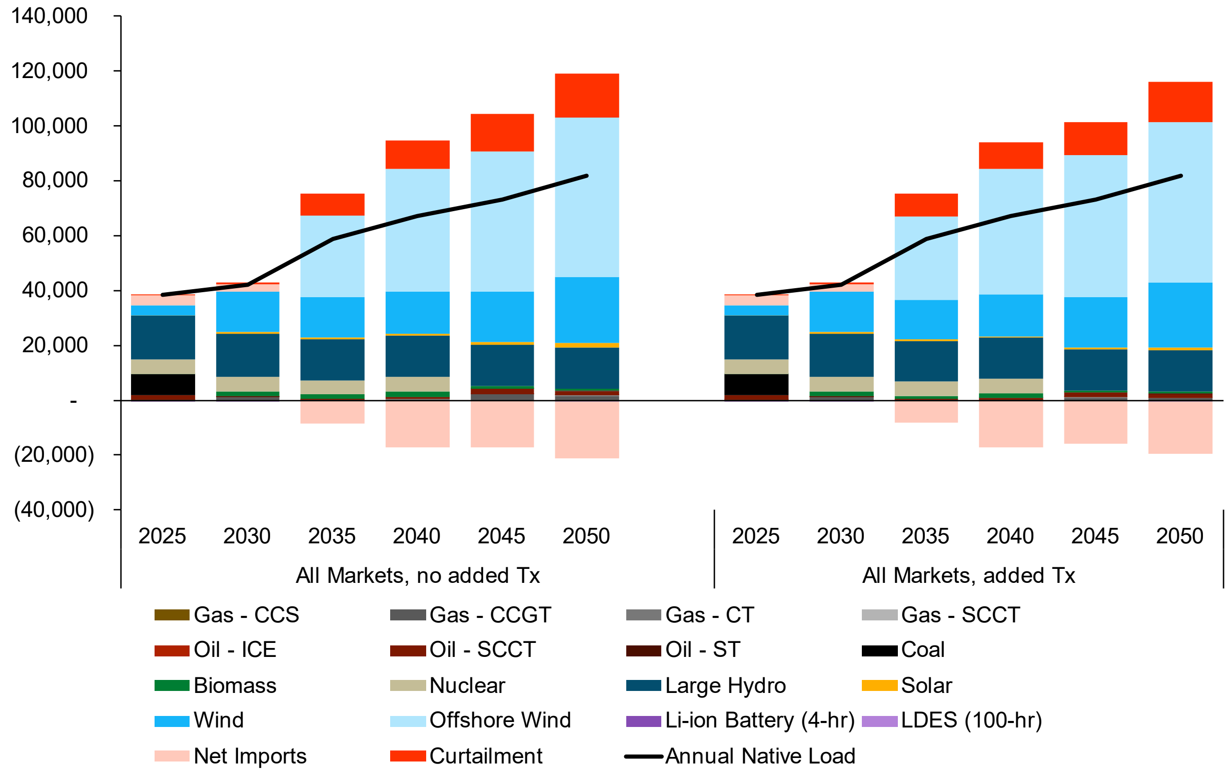
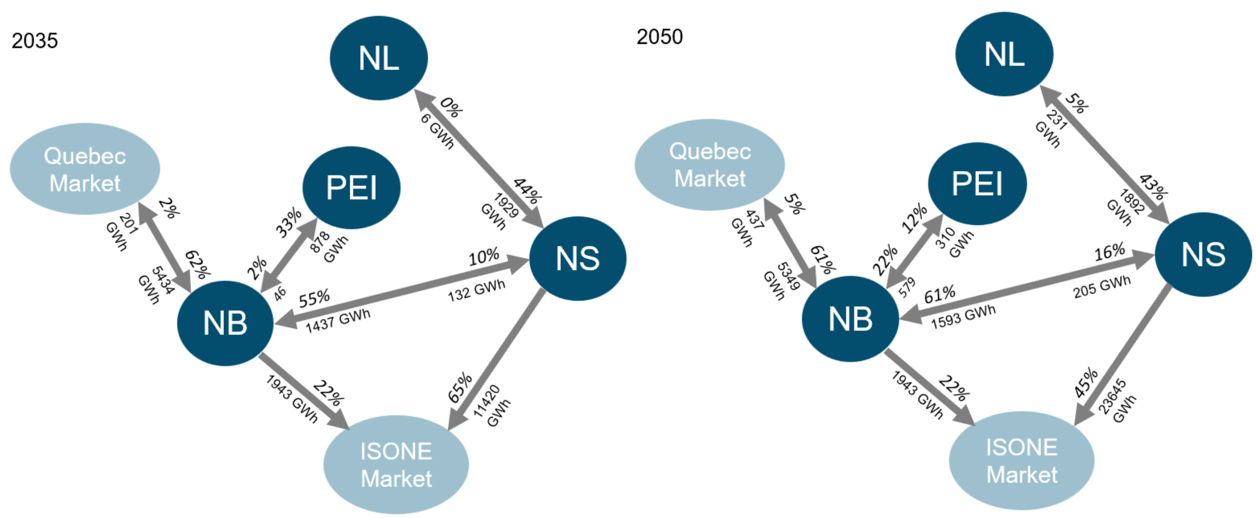


Figure 37. Line Utilization (%) and Flow (GWh), With (bottom) and Without (top) Added Transmission



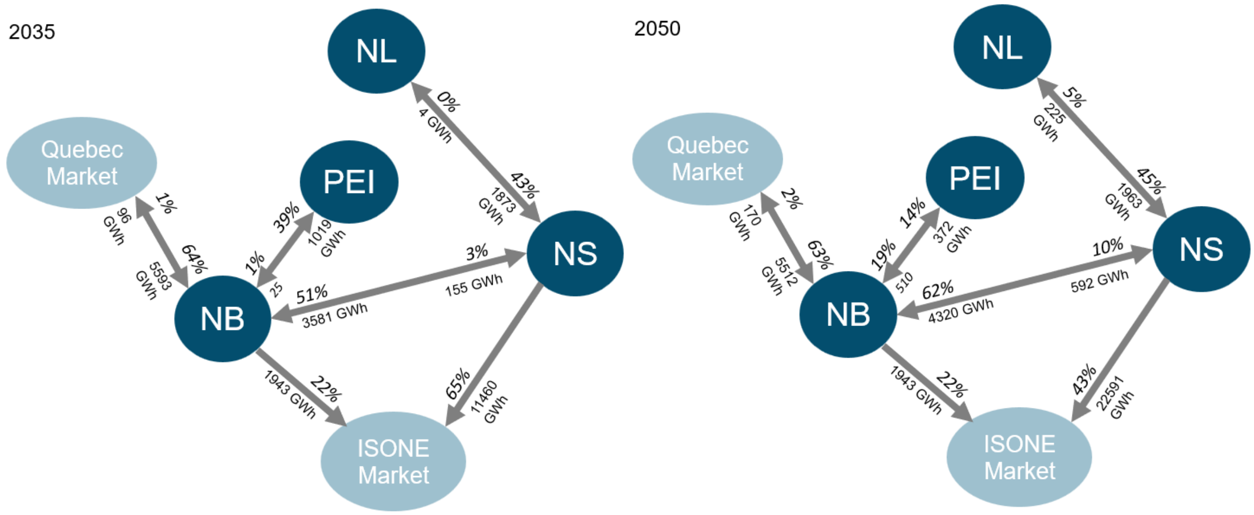


Figure 38. Average Month-Hour Curtailment in 2050 (MW)

Without additional NS-NB transmission

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	2,351	2,655	2,518	1,946	1,787	1,353	1,599	2,633	2,419	2,154	1,852	1,529	399	422	720	374	312	407	705	1,055	1,214	1,896	2,099	2,236
February	1,008	1,000	1,236	747	737	357	276	1,193	420	360	1,107	2,059	2,821	3,166	3,353	4,048	4,126	3,998	4,339	4,042	3,832	3,728	2,267	2,504
March	3,680	1,677	1,543	1,298	1,527	2,360	3,981	1,566	3,411	3,542	3,804	4,978	7,239	6,965	6,383	5,836	3,939	3,545	3,627	3,457	3,704	3,729	3,539	3,514
April	4,079	1,710	3,901	5,085	4,801	3,851	6,687	4,601	5,265	3,972	3,615	4,037	3,490	4,625	3,318	4,833	3,120	2,350	898	1,630	1,893	1,934	1,421	1,460
May	3,178	3,177	3,003	2,546	2,456	5,662	6,081	4,815	4,734	4,487	3,323	3,896	5,103	5,327	5,377	5,625	5,539	2,767	2,713	2,932	3,294	3,347	1,886	1,888
June	1,713	2,004	2,546	2,447	2,491	2,124	2,382	2,652	2,821	4,451	5,539	4,206	3,554	3,914	3,522	3,334	3,829	2,059	965	1,128	1,296	1,877	1,640	1,185
July	3,717	4,339	4,448	4,971	5,689	7,493	7,381	6,994	6,637	5,906	5,355	3,676	3,363	3,271	4,158	3,484	3,376	420	570	824	795	1,501	2,087	1,876
August	3,604	3,975	3,751	3,237	3,235	3,255	4,802	4,186	3,530	2,499	2,030	1,498	1,129	995	1,925	1,114	1,213	1,672	1,760	1,160	2,747	2,829	3,217	3,127
September	1,650	2,117	1,607	1,649	1,944	1,850	4,280	4,369	5,090	3,672	4,386	2,473	2,001	1,799	2,312	3,156	2,639	3,179	3,747	4,649	2,132	1,889	2,484	3,537
October	4,082	3,868	3,698	2,582	2,620	2,168	6,403	7,542	6,776	6,989	7,310	7,344	7,071	6,180	5,999	2,263	1,362	1,173	947	776	829	869	1,335	1,114
November	1,639	1,779	1,763	1,946	1,593	1,142	974	1,473	1,847	1,837	2,414	2,247	2,852	1,039	712	597	808	787	1,176	2,148	6,021	6,865	7,199	7,232
December	3,389	3,958	3,361	2,299	1,607	1,462	1,309	1,221	1,428	1,319	1,284	2,921	2,169	1,944	1,574	504	993	1,045	1,296	2,919	1,675	1,223	1,855	2,164

With additional NS-NB transmission

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	2,068	2,239	2,265	1,816	1,631	1,405	1,577	2,488	2,285	1,967	1,700	1,492	523	431	503	473	320	396	715	993	1,190	1,699	2,021	2,145
February	999	944	1,029	792	580	308	300	1,045	358	249	898	1,883	2,560	3,221	3,165	3,880	3,966	3,767	3,902	3,897	3,632	3,509	2,171	2,587
March	3,574	1,532	1,556	1,124	1,419	2,219	3,769	1,397	3,165	3,583	3,773	4,591	7,158	6,759	6,243	5,314	3,650	3,325	3,416	3,341	3,608	3,568	3,575	3,364
April	3,296	1,634	3,531	4,613	4,630	3,643	6,249	4,495	4,823	3,717	3,188	3,737	2,994	4,077	2,921	4,471	2,696	2,133	830	1,493	1,748	1,755	1,311	1,344
May	2,940	3,111	2,753	2,544	2,205	5,615	5,900	4,259	4,135	3,955	2,732	3,486	4,601	4,903	5,043	5,323	5,296	2,621	2,633	2,467	2,891	2,960	1,493	1,439
June	1,513	1,913	2,488	2,378	2,239	2,062	2,027	2,318	2,469	4,096	5,071	3,719	3,133	3,116	3,199	3,037	3,425	1,999	923	1,095	1,274	1,825	1,640	1,086
July	3,831	4,071	4,395	4,835	5,407	7,123	7,115	6,337	6,276	5,505	4,679	3,174	2,844	2,743	3,549	3,085	2,678	438	499	706	809	1,459	2,065	1,790
August	3,492	3,761	3,547	3,170	3,339	3,184	4,413	3,854	3,135	2,027	1,651	1,132	876	843	1,715	1,399	1,489	1,625	1,712	1,197	2,579	2,798	2,885	3,006
September	1,613	2,128	1,531	1,666	1,785	1,799	4,062	4,041	4,709	3,047	3,745	2,345	1,896	1,623	1,893	2,678	2,536	3,167	3,752	4,780	1,958	1,868	2,422	3,469
October	3,931	3,757	3,649	2,627	2,548	2,051	6,130	7,532	6,505	6,862	6,944	7,389	6,552	5,833	5,756	2,151	1,262	1,105	953	775	813	842	1,230	1,093
November	1,716	1,600	1,690	1,950	1,573	1,292	1,197	1,549	1,708	1,590	1,995	1,915	2,360	833	677	476	758	587	975	1,795	5,978	6,831	7,047	7,230
December	3,107	3,804	3,360	1,878	1,448	1,142	1,147	1,047	1,508	1,279	1,134	2,360	1,753	1,556	1,131	271	912	879	1,208	2,837	1,608	1,284	1,908	2,201

Figure 39. Average Month-Hour Line Utilization from Nova Scotia to New Brunswick in 2050 (%)

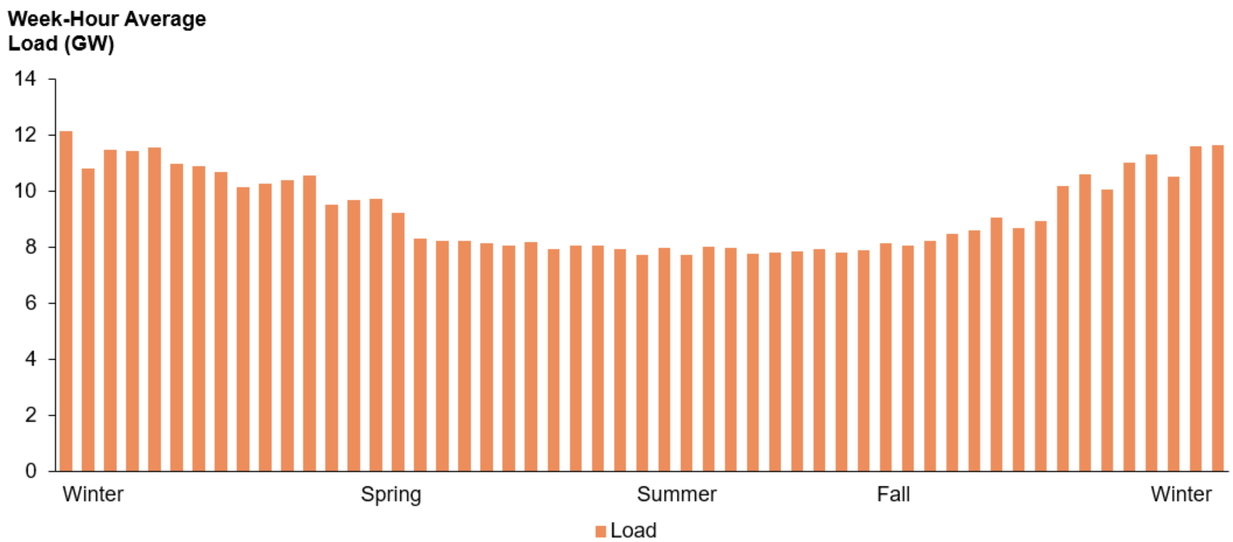
Without additional NS-NB transmission

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	74%	74%	74%	78%	74%	74%	82%	74%	100%	89%	100%	100%	100%	61%	61%	61%	61%	61%	49%	30%	0%	0%	0%	17%
February	45%	56%	25%	25%	31%	100%	100%	100%	100%	100%	100%	100%	100%	64%	64%	64%	100%	100%	61%	36%	60%	45%	36%	36%
March	0%	0%	0%	45%	58%	58%	49%	45%	45%	45%	45%	58%	13%	13%	54%	91%	100%	100%	100%	100%	55%	55%	55%	55%
April	67%	67%	100%	67%	67%	28%	20%	62%	100%	100%	100%	70%	67%	86%	100%	86%	100%	100%	67%	0%	0%	8%	0%	0%
May	29%	29%	29%	29%	29%	29%	32%	34%	90%	90%	90%	90%	21%	2%	10%	10%	67%	10%	10%	10%	10%	10%	10%	10%
June	40%	100%	100%	100%	40%	100%	40%	40%	40%	40%	40%	40%	40%	28%	77%	77%	77%	77%	77%	83%	62%	28%	19%	0%
July	26%	62%	74%	74%	100%	100%	100%	100%	39%	99%	100%	100%	100%	100%	100%	100%	100%	100%	100%	72%	39%	39%	39%	39%
August	100%	45%	100%	100%	74%	74%	74%	74%	74%	88%	74%	74%	74%	83%	100%	100%	100%	42%	42%	42%	42%	42%	42%	36%
September	83%	37%	83%	83%	83%	83%	90%	83%	83%	83%	83%	83%	83%	83%	95%	83%	75%	37%	37%	53%	53%	53%	53%	53%
October	23%	23%	23%	23%	23%	23%	23%	37%	68%	68%	37%	36%	27%	68%	100%	100%	77%	77%	77%	77%	77%	77%	100%	77%
November	7%	7%	7%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	7%	67%	96%	99%	45%	34%	33%	33%	33%
December	77%	32%	32%	62%	100%	97%	100%	100%	55%	100%	100%	55%	23%	55%	55%	41%	55%	55%	55%	55%	32%	77%	77%	77%

With additional NS-NB transmission

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	74%	74%	74%	79%	74%	88%	100%	74%	100%	85%	100%	100%	98%	72%	66%	61%	61%	61%	61%	23%	0%	0%	0%	17%
February	45%	33%	4%	20%	50%	73%	100%	100%	100%	81%	100%	100%	98%	64%	64%	64%	99%	98%	65%	36%	65%	50%	36%	36%
March	8%	0%	7%	48%	56%	58%	66%	45%	74%	45%	53%	58%	13%	19%	51%	82%	100%	100%	92%	68%	55%	55%	55%	55%
April	100%	67%	100%	80%	67%	20%	33%	49%	89%	100%	95%	64%	85%	94%	100%	100%	100%	100%	68%	1%	0%	7%	26%	0%
May	22%	19%	29%	29%	29%	36%	55%	90%	97%	91%	90%	100%	84%	57%	49%	49%	67%	10%	10%	10%	10%	10%	10%	10%
June	23%	97%	100%	100%	32%	52%	40%	32%	40%	67%	50%	82%	77%	87%	74%	77%	81%	80%	77%	79%	64%	22%	21%	0%
July	36%	64%	74%	74%	100%	100%	100%	100%	59%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	49%	39%	39%	39%	39%
August	73%	51%	76%	73%	74%	74%	74%	80%	74%	94%	74%	74%	100%	100%	99%	87%	99%	42%	42%	60%	78%	39%	42%	33%
September	90%	49%	83%	83%	83%	100%	100%	83%	83%	83%	83%	76%	83%	83%	89%	65%	59%	37%	37%	53%	21%	18%	17%	17%
October	25%	34%	23%	18%	23%	22%	17%	31%	52%	40%	32%	34%	43%	68%	95%	100%	77%	77%	77%	77%	78%	66%	94%	77%
November	7%	7%	7%	46%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	7%	67%	83%	71%	59%	36%	40%	33%	33%
December	77%	32%	32%	73%	100%	97%	100%	96%	49%	100%	100%	72%	29%	52%	55%	23%	55%	55%	47%	59%	70%	77%	77%	77%

Figure 40. Week-Hour Average Load vs Capacity Curtailment (MW), 2050 (left curtailment bar is without added Tx, right bar is with added Tx)



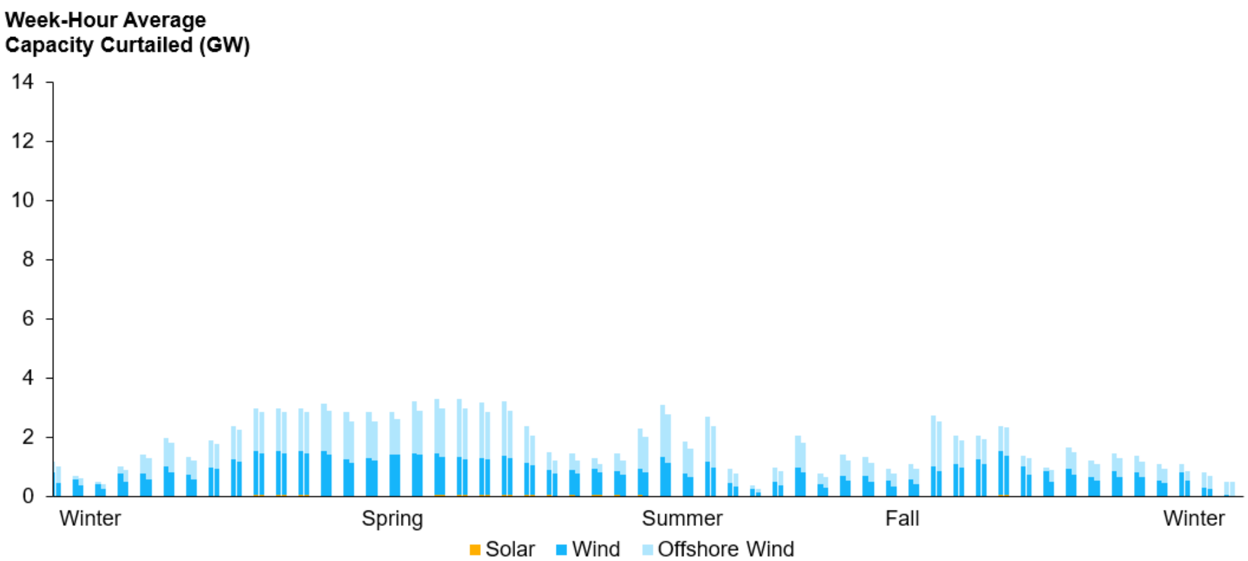


Figure 41 and 42 show the differences in NPV and annual cost of energy between the sensitivities with and without additional transmission capacity. Overall, the extra transmission results in an approximately $300 million reduction in NPV. Despite slightly reduced market revenues, the reduced offshore wind curtailment has a greater impact on decreasing cost. These sensitivity results demonstrate the value additional transmission capacity between Nova Scotia and New Brunswick could provide to reduce curtailment and lower the annual cost of energy while supporting a decarbonized future in the Atlantic Provinces.

Figure 41. Modeled Cost Comparison, NPV ($MM) With and Without Added Tx Capacity

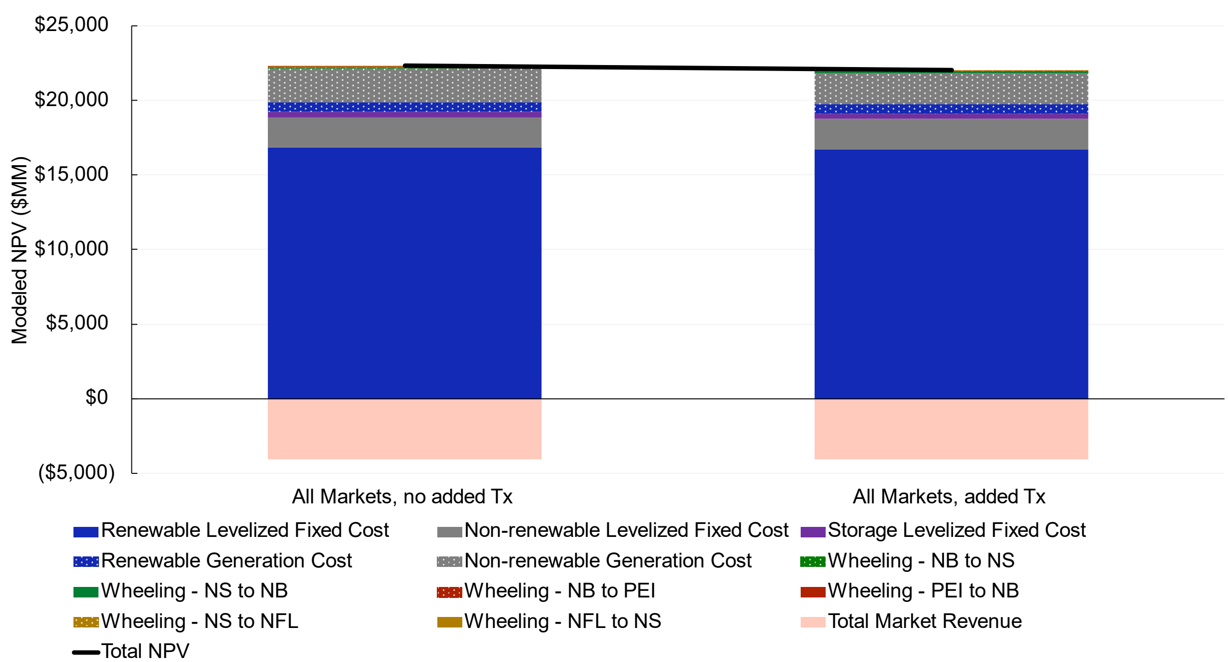
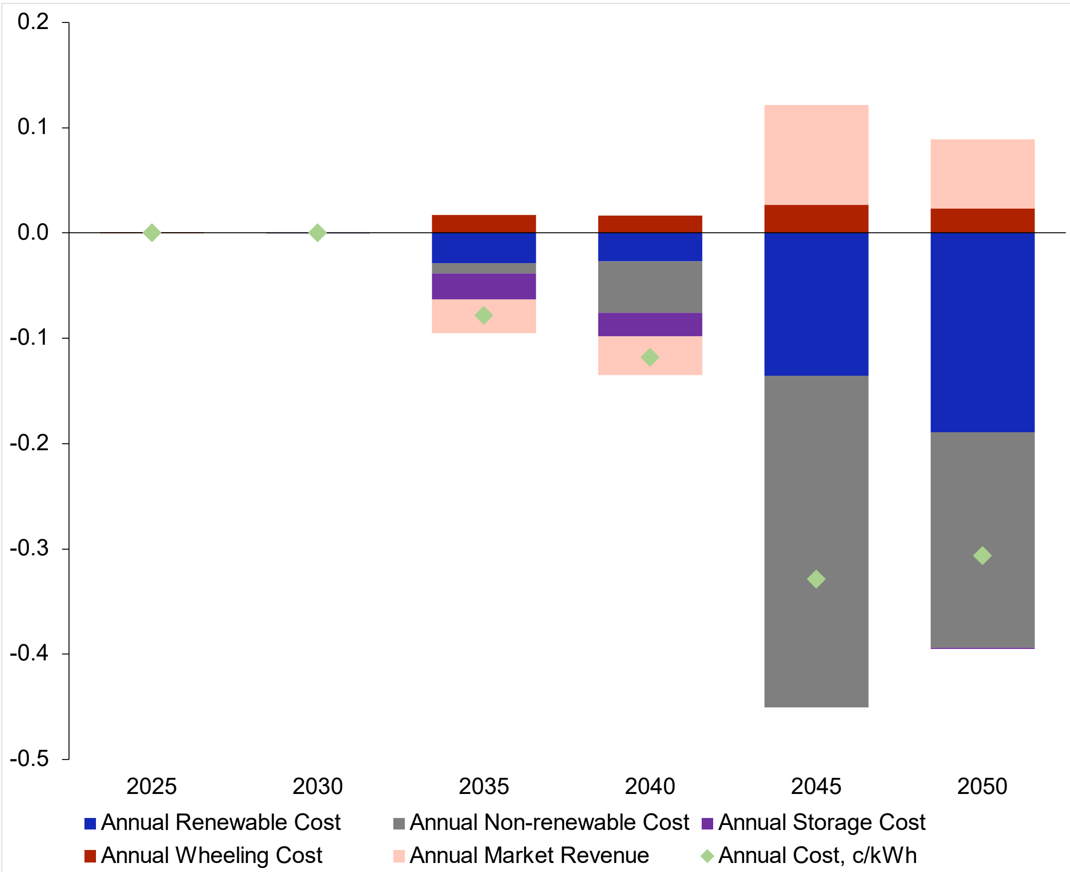


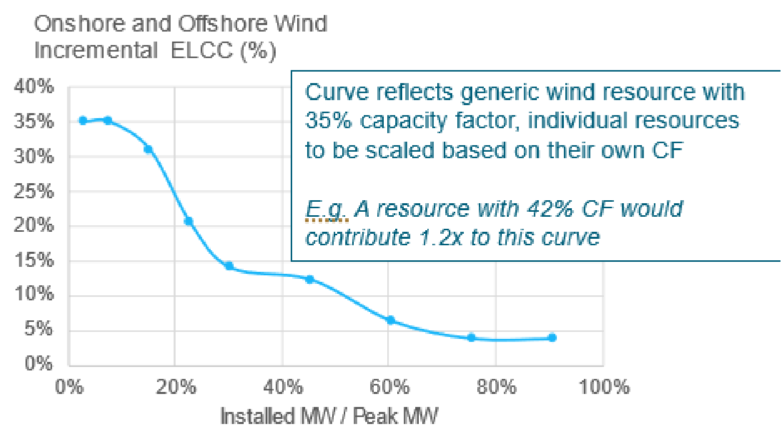
Figure 42. Modeled Cost Comparison, Annual Cost of Energy (nominal ¢/kWh) with Added Tx Capacity Relative to without 500 MW additional NB/NS Transmission



Appendix B. Additional Input Assumptions

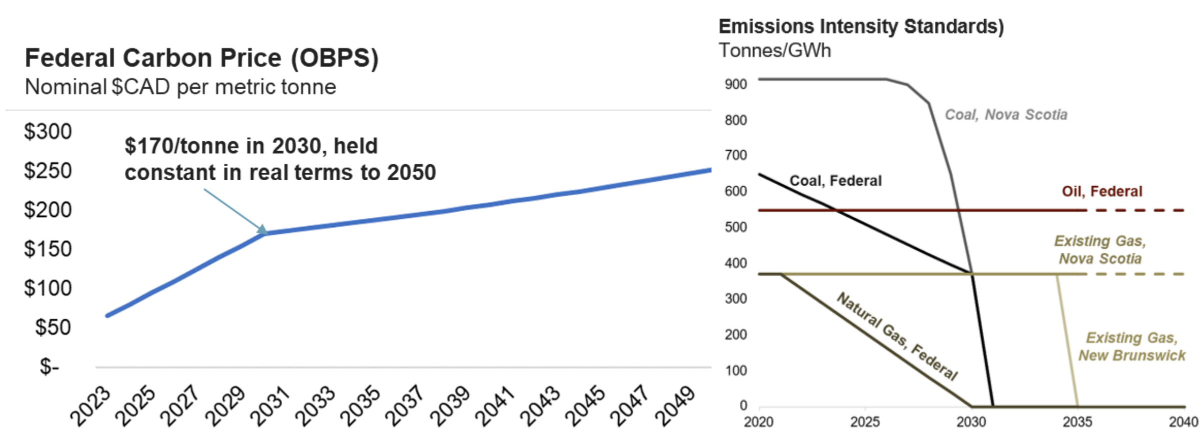
B.1. Wind Effective Load Carrying Capability (ELCC) Curve Assumption

Figure 43. Onshore and Offshore Wind ELCC Curve



B.2. Carbon Pricing and Policy Assumptions

Figure 44. Federal Carbon Pricing Policy and Emissions Intensity Standards



B.3. Additional Import-Export Assumptions

Figure 45 and 48 below illustrate the historical average flows across key interfaces.

Figure 45. 2023 Month-Hour Average Flows from New Brunswick to ISO New England (MW)[30]

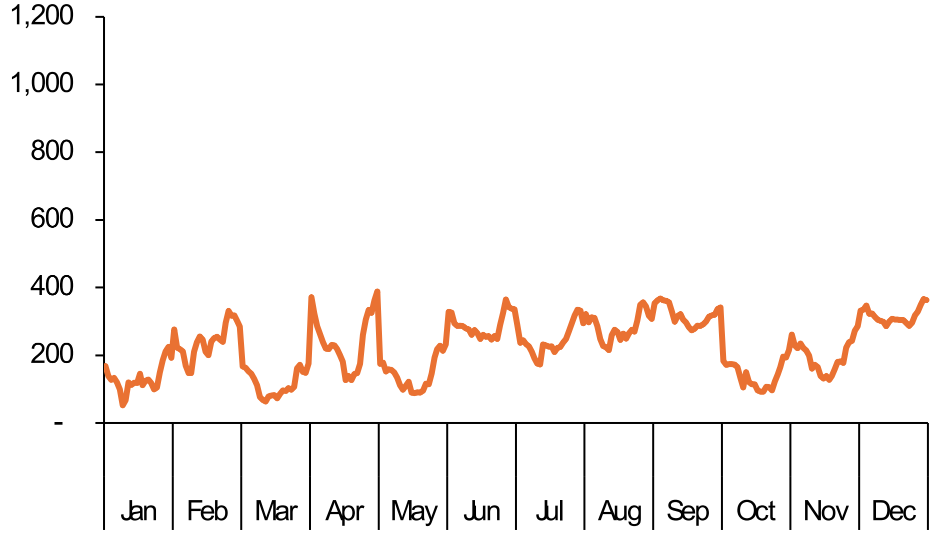
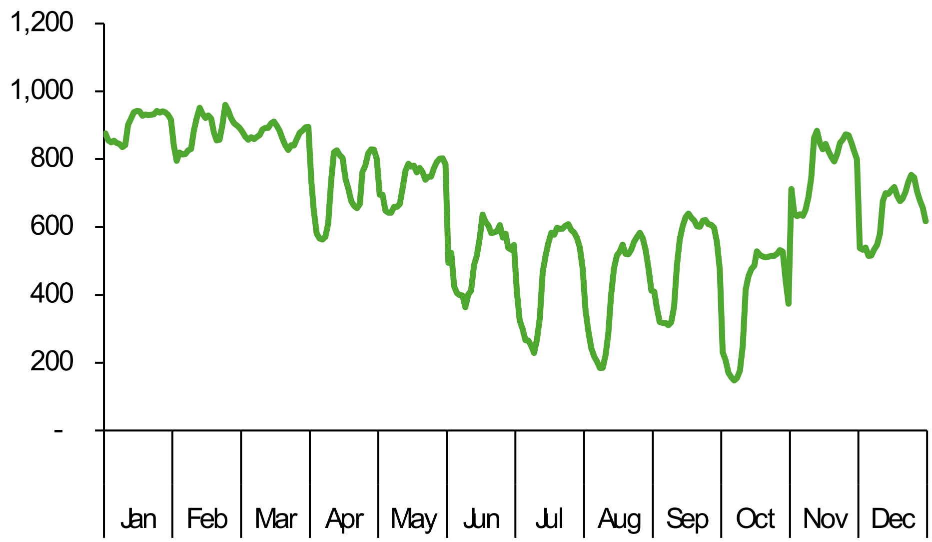


Figure 46. 2023 Month-Hour Average Flows from HydroQuébec to New Brunswick (MW)[31]



The NB-ISONE and NS-ISONE interfaces export to a market represented by a fixed hourly market price established using the E3 2023 ISO New England market price forecast. The HQ-NB interface interacts with the HydroQuébec market, which is represented using a flat, synthetic market price of $5.50/MWh (plus inflation). This price was selected to be slightly greater than the sum of the renewable integration charge ($2/MWh plus inflation) and the hurdle rate used for exports to HydroQuébec ($3.10/MWh plus inflation).

[30] https://tso.nbpower.com/Public/en/system_information_archive.aspx
[31] https://tso.nbpower.com/Public/en/system_information_archive.aspx

The price is high enough to encourage exports of excess renewable energy when the only other option is curtailment but low enough to discourage exports to HydroQuébec over serving local loads.

Table 7. External Market Interface Assumptions Summary[32]

External Market	Connected Atlantic Province	Hourly Purchases	Hourly Sales	Market Price
ISO-New England	New Brunswick	None	Fixed to 2023 month-hour average flows	E3 Price Forecast
Hydro Québec	New Brunswick	Up to 2023 month-hour average flows	Up to 1,000 MW	$5.50 plus inflation
ISO-New England	Nova Scotia	None	Up to installed offshore wind capacity built for export	E3 Price Forecast

B.4. Additional Hydrogen Assumptions

Hydrogen Demand Percentages Assumed in E3 PATHWAYS Model

Table 8. Percent of Energy Demand Assumed to be Met with Hydrogen

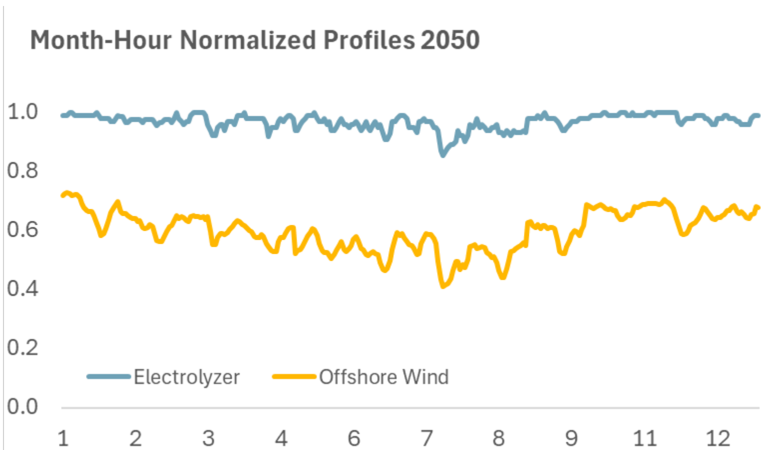
Sector	End Use	2030	2035	2040	2045	2050
Industry	Heating	0%	15%	30%	40%	50%
Transportation	Heavy Duty Vehicles	25%	38%	50%	65%	80%
Transportation	Aviation	0%	21%	42%	56%	70%
Residential	Heating	1%	1%	1%	1%	0%
Commercial	Heating	1%	1%	1%	0%	0%

[32] As noted elsewhere in this report, though Hydro Quebec and Labrador also have transmission linkages, those are not included in this study due to lack of publicly available data, and lack of interactive effects with the other Atlantic Provinces. Flows from Labrador to the Newfoundland Island System via the Labrador Island Link (and flow on to Nova Scotia via the Maritime Link) are modeled, effective capturing the impact that Labrado based generation has on portfolios, generation and dispatch elsewhere in the Atlantic Provinces.

Note: Aviation percentages are indicative of GJ SAF produced with H2, not GJ H2. The H2 to electrofuel conversion ratio is 1.224 GJ H2/GJ fuel

E3 developed an hourly/seasonal hydrogen load shape that assumes it is slightly flexible to demand, and that it backs up offshore wind some limited amounts of grid power as needed. The load shape assumes that electrolyzers in the Atlantic Provinces operate at a 97% capacity factor (with a 72% efficiency), and their utilization behavior reflects the seasonal availability of regional offshore wind. The month-hour load shape is shown in Figure 47 below.

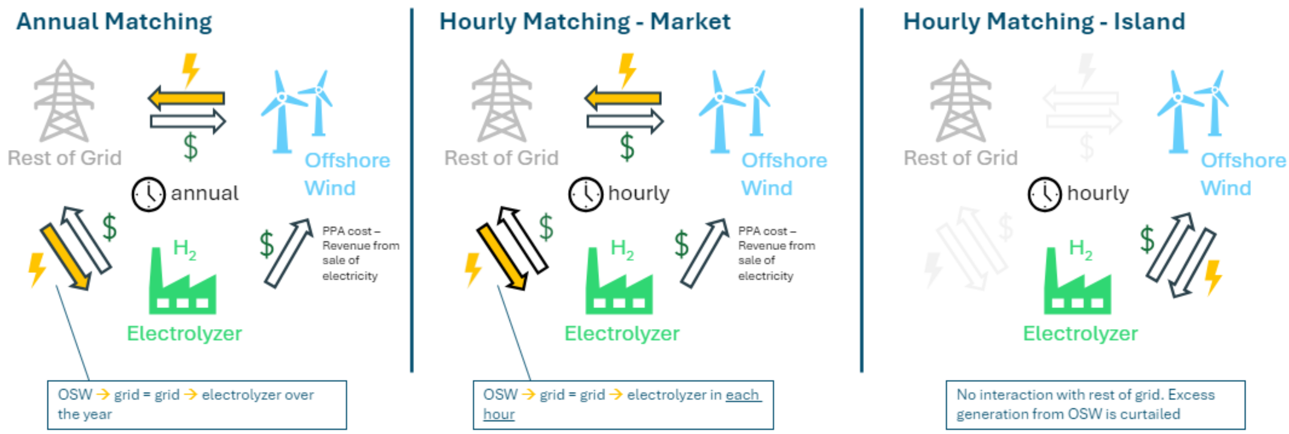
Figure 47. Month-Hour Normalized Hydrogen Load Profile



B.5. Hydrogen Production Costs

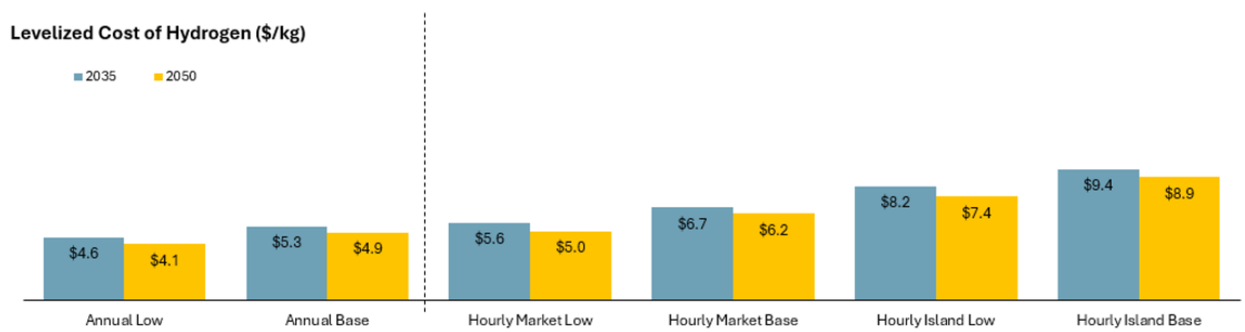
The cost of hydrogen was calculated for 3 operational scenarios—matching renewable production with electrolyzer charging on an annual basis (Annual Matching), matching renewable production with electrolyzer charging on an hourly basis, allowing interaction with the grid (Hourly Matching – Market), and matching renewable production with electrolyzer charging on an hourly basis in isolation from the grid (Hourly Matching – Island). E3 also ran two cost scenarios, a base scenario and a low-cost scenario that assumed lower offshore wind and alkaline electrolyzer capital costs. Both cost scenarios included the Canadian hydrogen investment tax credit. For operational parameters, E3 assumed that the electrolyzer operated at a 90% capacity factor and the offshore wind generated at a 60% capacity factor.

Figure 48. Operational Configurations in REMATCH



The results of this analysis showed that the least-cost sizing of offshore wind to electrolyzer capacity was a ratio of 1.5 to 1 for annual matching, and 3 to 1 for hourly matching. However, even in the low-cost annually matched scenario, the cost of hydrogen is $4/kg by 2050. In the hourly matched scenarios (compliant with European import regulations), this cost increases to as high as $7/kg in the scenario where the developer can sell excess power to the grid.

Figure 49. Levelized Cost of Hydrogen



Note: Outputs align with scenarios defined above (see previous figure).

It’s important to note this analysis is sensitive to assumptions about the future that are highly uncertain. For example, these costs could be brought down substantially by additional federal hydrogen policy, like subsidies to developers on a production basis. Additionally, this analysis assumes offshore wind as the primary source of energy for hydrogen because the focus of the broader report is on offshore wind. Offshore wind capital costs also comprise the majority of the cost of hydrogen production calculated in this analysis. However, offshore wind is not the cheapest source of clean energy in the Atlantic Provinces, and most projects underway today are powered by *onshore* wind generation, which is substantially cheaper. Additionally, this analysis is solely focused on production, and does not take into account the other infrastructure advantages the Atlantic Provinces have, like their abundant geologic hydrogen storage potential, or shipping costs reduced by its proximity to Europe. However, to be competitive on a global scale, the Atlantic Provinces would need a substantial mobilization of capital and increased ambition in federal policy to enable the region to become a major exporter of hydrogen.

B.6. Known Existing Hydrogen Projects

Table 9. List of Existing Hydrogen Projects in Atlantic Provinces

Province	Project	Operational by	Details	Power Source
New Brunswick	Irving Oil	2023	5 MW electrolyzer capacity	N/A
New Brunswick	Port of Belledune & Cross River Infrastructure	2027	N/A	300-600 MW of new clean capacity
New Brunswick	[CLASSIFIED]	N/A	N/A	300 MW wind capacity
Newfoundland & Labrador	Copenhagen Infrastructure Partners/ABO Energy	2035	400,000 tons of hydrogen per year	5 GW onshore wind capacity, developed in three phases
Newfoundland & Labrador	Abraxas Power/Exploits Valley Renewable Energy Corp	N/A	200,000 tons of hydrogen and 1,000,000 tons of ammonia annually	3.5 GW onshore wind capacity and 150 MW solar capacity
Newfoundland & Labrador	EverWind - Burin Peninsula	2028 (partial)	5.5 GW electrolyzer capacity	10 GW of onshore wind and 2.5 GW of solar capacity (2 GW wind will be online by 2028)
Newfoundland & Labrador	North Atlantic Refining Ltd	N/A	90,000 metric tons of green hydrogen annually	N/A
Newfoundland & Labrador	Pattern Energy - Argentia Project	2028	160 MW electrolyzer capacity	300 MW onshore wind capacity
Newfoundland & Labrador	Project Nujio'qonik - World Energy GH2	2025	1.5 GW electrolyzer capacity	3 GW onshore wind capacity
Nova Scotia	Bear Head Energy	2027	2 GW electrolyzer capacity	3.5 GW clean capacity
Nova Scotia	EverWind Fuels - Point Tupper	2025	200,000 tons of hydrogen in 2025 and 1 million tons 2026 onwards	527 MW of onshore wind capacity by 2025, 650 MW by 2026
Nova Scotia	Simply Blue	N/A	N/A	600 MW powered by onshore wind and solar
Prince Edward Island	Aspin Kemp & Associates	N/A	2 MW of electrolyzer capacity	N/A