New Nouveau Brunswick
CANADA

September 16, 2021

[redacted]

This is in response to your request under the *Right to Information and Protection of Privacy Act* (RTIPPA) forwarded on July 6, 2021, and received on July 7, 2021, for the following:

"Please provide any analysis or reports that examine what would need to happen with the province's electricity system if:
– consumers in the province switched to electric vehicles instead of diesel/gas-powered; and/or
– if natural gas was phased out in the province as a fuel for heating and consumers used electric heat instead
(Changes would include: new generation capacity required, transmission/distribution system upgrades, other requirements, the cost for the changes, etc.)"

Time Period: January 1, 2021 to July 6, 2021

Please find enclosed records relevant to your request.

If you are not satisfied with this decision, you may file a complaint with the Office of the Ombudsman (Access and Privacy Division) pursuant to subparagraph 67(1)(a)(i) by submitting the appropriate form within 40 business days of receiving this response, or refer the matter to a judge of the Court of Queen's Bench pursuant to paragraph 65(1)(a) by submitting the

Natural Resources and Energy Development / Ressources naturelles et Développement de l'énergie
P.O. Box 6000 / C. P. 6000 Fredericton New Brunswick / Nouveau-Brunswick E3B 5H1
Tel. / Tél. : 506-453-2501 Fax / Téléc. : 506-453-2930
www.gnb.ca

appropriate form within 40 business days of receiving this response. Information regarding the complaint and appeal process can be found at the following link:

https://www2.gnb.ca/content/gnb/en/departments/finance/office_of_the_chief_information_officer/content/rti.html.

Should you have any questions regarding this matter, please contact Ms. Hajnalka Hartwick, RTIPPA Coordinator, at (506) 453-3810 or at Hajnalka.Hartwick@gnb.ca.

Sincerely,

Tom MacFarlane
Deputy Minister

Enclosure

c. Hajnalka Hartwick, RTIPPA Coordinator

Atlantic Clean Power Planning Committee

July 2021

Potential Benefits of Regional Coordination in a Low-Carbon Future

Ensuring Electric Reliability

Energy+Environmental Economics

Project Team:

Sharad Bharadwaj

Mengyao Yuan

Jasmine Ouyang

Michaela Levine

Nick Schlag

Robbie Shaw

Charles Li

Arne Olson

Contents

Figures

Tables

1 Executive Summary

Canada and the Atlantic provinces, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland and Labrador, have adopted various greenhouse gas emissions reduction targets. The electricity system will play a key role in achieving these targets through decarbonization of energy supply and enabling electrification of those buildings and transportation end uses which currently consume mostly fossil fuels.

This study investigates the implications of electrification on electricity supply planning in the region, with an emphasis on the potential economic benefits of increased regional coordination.[1] The key research questions addressed by this study are as follows:

1. What is the role that electrification of buildings and transportation might play in reducing greenhouse gas emissions in the region, and what would the annual electricity demand and peak electric loads be under an electrification scenario consistent with regional decarbonization trajectories?
2. What role might regional coordination of power supply options play in meeting the demand for low-carbon energy and firm capacity?

To investigate these questions, E3 performed a deep decarbonization PATHWAYS study for the region to estimate the annual load and peak load which each province might face under a scenario consistent with deep decarbonization trajectories. These annual and peak load forecasts served as inputs into E3's RESOLVE model, an optimal capacity expansion and dispatch model which was used to generate least-cost electricity supply resource portfolios. The electricity sector modeling was run with the inclusion of large clean energy injections into the Maritimes (which could be sourced from a variety of sources, such as hydropower from Quebec and/or Newfoundland and Labrador) to test the gross benefits that such a large clean energy injection would have to the regional electricity system. The key findings of this analysis are as follows:

+ **Regional Decarbonization in Atlantic Canada will require transformational change in all sectors of the economy**. Key strategies for mitigating economy-wide greenhouse gas emissions are: continued deployment of energy efficiency; widespread electrification of end uses in buildings and transportation; deep decarbonization of electricity supplies.

+ **Electricity demand is likely to increase significantly over the next three decades.** As electrification of transportation and building end-uses continues, the region is likely to see growth in both annual electricity sales as well as peak electricity demand. These increases occur despite significant energy efficiency and demand response measures which are included in the scenarios. Absent these measures, demand growth would be even higher.

+ **Renewable electricity generation will play a major role in providing zero-carbon energy to the region.** Renewable generation is needed to displace fossil fuel generation in the regional electricity system and to provide zero-carbon energy for vehicles and buildings. Regardless of regional coordination measures to import dispatchable, clean energy from Newfoundland and Labrador or Quebec, the Maritimes will require significant construction of in-region renewable energy to provide zero-carbon energy and decarbonize the electric power supply.

+ **Achieving very deep carbon reductions in the electric supply sector will become increasingly difficult in the Maritimes as existing thermal generation is retired**. Due to technical limitations on the existing

[1] This study does not examine in detail the decarbonization actions necessary in sectors which are not likely to cause growth in electric load, such as non-combustion sources or in industrial process emissions.

system's ability to integrate wind and solar, the need for supply during long periods of variable renewable resource unavailability, and the relatively limited geographic diversity of variable renewable resource options within the region the scope for continuing to integrate variable renewable resource options within the Maritimes is limited. Achieving very deep levels of decarbonization will thus require firm, dispatchable low-carbon energy and capacity to ensure reliability. Without broader regional coordination, this would mean leaning on resources which have not yet proven commercial viability, such as advanced nuclear or carbon capture and sequestration.

+ **Imported low carbon energy has significant value which grows over time as carbon targets become more stringent and as reliability requirements become more difficult to meet.** Imported hydropower or other dispatchable, clean energy can meet the need for zero-carbon electricity and the need for firm capacity for system reliability, acts as a hedge against significant uncertainty in commercial development of low-carbon baseload, and shows significant value under a wide variety of uncertainties, in particular in scenarios examining 2030 coal retirement.

2 Chapter One: Introduction

2.1 Study Motivation

The federal government of Canada and the provincial governments within the Atlantic Canada region continue to take steps to reduce economy-wide carbon emissions. Since 2005, the electric sector in the region has undergone a significant reduction in emissions due primarily to reductions in coal use in Nova Scotia and New Brunswick and reduced fuel oil use in Newfoundland and Labrador. Nevertheless, to achieve levels of decarbonization of the economy in line with those necessary to meet Paris climate targets or even more aggressive net-zero targets, more action will be required.

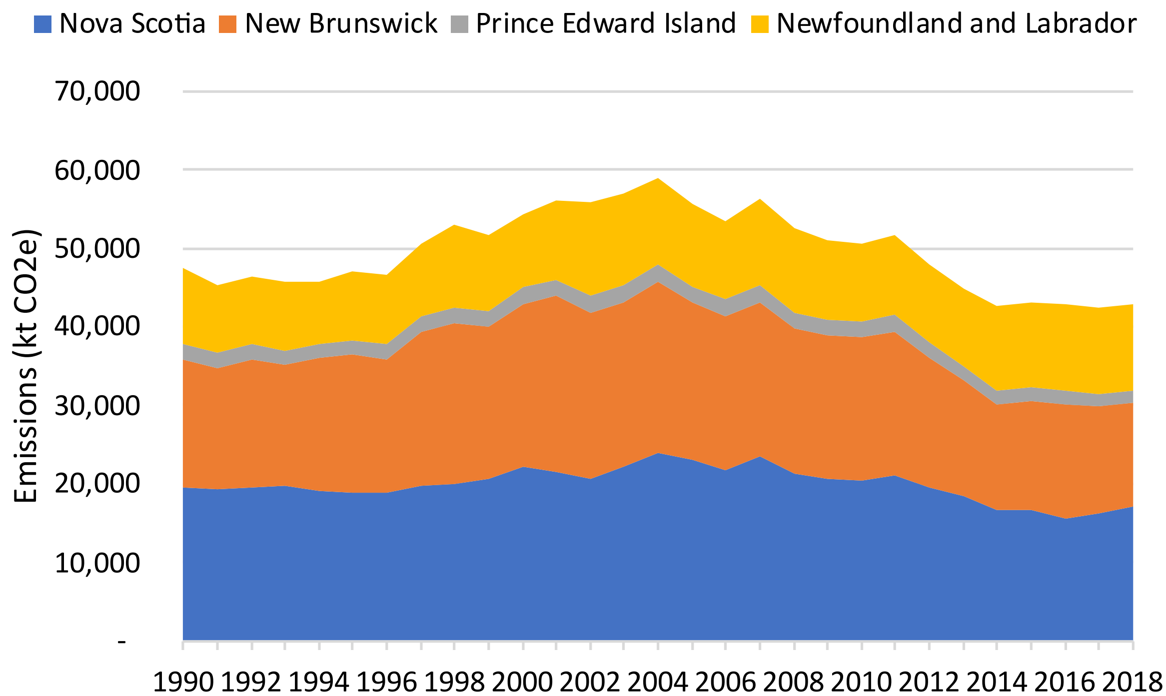
Research in jurisdictions across North America has identified common themes or “pillars” to achieving economy-wide deep decarbonization. These pillars include energy efficiency, electrification, decarbonizing the energy supply, and reducing emissions from non-energy sources. Electrification is a key pillar of the economy-wide transition because electrified end uses are significantly more efficient than fossil alternatives (e.g., battery electric vehicles are much more efficient than internal combustion engine vehicles), and because electrification can be combined with a decarbonization of the electric power supply to achieve significant cumulative reductions in emissions.

This study investigates a transformation of the Atlantic Canada region’s energy supply portfolio to one in which electricity, already used significantly across the region, becomes the dominant form of energy as most buildings and transportation end uses are electrified. The focus of this study is on the implications such widespread electrification would have on the electric power supply within the region, and how regional coordination may reduce costs, maintain reliability, and reduce carbon emissions.

Other sectors of the economy will need to pursue other policies which may not affect the electricity sector but those are not core to the scope of this work and are not investigated in this study.

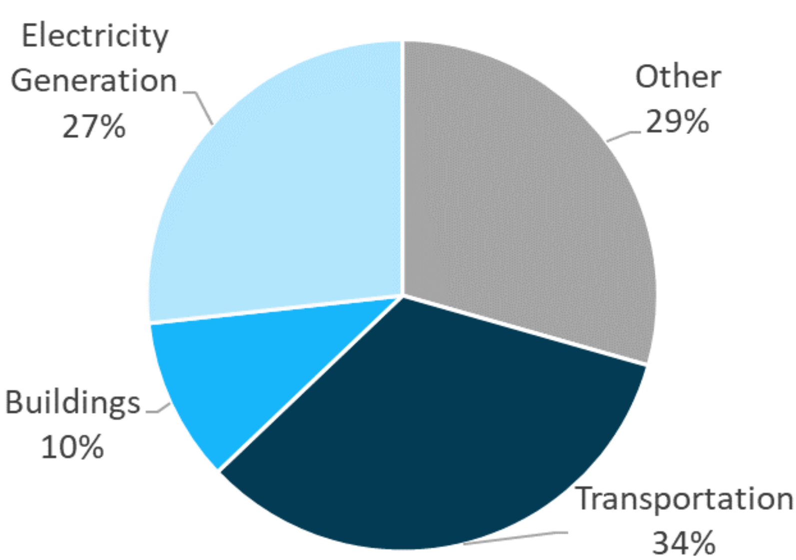
Emissions in the Atlantic Canada region in 2016 equaled 42 million metric tons of CO_2-equivalent (MMT CO_2e), or roughly 6% of the Canadian total. Emissions within the region have declined since peaking in 2004, as seen in Figure 2-1. As seen in Figure 2-2, which shows the relative proportion of emissions by sector in the region in 2020, transportation is the sector with greatest carbon emissions, followed by electric power. Other significant emissions come from non-combustion and non-energy sources and from industries, oil and gas, and refining. Finally, fuel consumption for residential and commercial buildings, primarily for heating and hot water, drive the remaining 10% of emissions.

Figure 2-1. Historical economy-wide GHG emissions by province since 1990



Source: Environment Canada

Figure 2-2. Atlantic Provinces estimated emissions by sector in 2020



Source: E3 analysis using PATHWAYS model

2.2 Goals of this Study

This study investigates the potential benefits of expanded regional coordination between the provinces in Atlantic Canada as they consider strategies to cost effectively meet economy-wide decarbonization targets safely, reliably, and at least cost. The focus is on two key research questions:

1. What is the size and scope of new loads which may come online due to electrification, primarily of buildings and transportation end uses; and
2. How does the electrification of these end uses affect the electricity system planning challenges each province faces, especially in the Maritime provinces which face the added challenge of the retirement of existing coal units in the next two decades? This study considers how pursuing regional coordination would affect electricity system planning.

2.3 Study Design

This study uses a suite of modeling tools to estimate the electric load implications of deep decarbonization economy-wide and consider the types of resources which could be used to meet this electric load safely, reliably, and under increased carbon reduction constraints. The study tools are discussed in more detail in Chapter 3, but in brief they include E3's PATHWAYS Model -- an economy-wide energy and emissions accounting model -- and E3's RESOLVE model -- an electricity system optimal capacity expansion and dispatch model.

First, PATHWAYS was run to generate electric load and electric peak forecasts under a high electrification scenario. These load and peak forecasts were then passed to RESOLVE, which optimized the electric supply portfolio of the region to minimize the costs of meeting these loads. First a reference scenario was run in which there is no new regional coordination beyond existing levels of interties (i.e., there are no new transmission lines interconnecting the provinces beyond those existing and operational in 2021); then, a variety of change cases were run in which we assume the availability of new transmission lines and associated energy and capacity to test the value that this line would provide. We test the benefits of two different types of regional coordination: a "high hydro" injection represents the construction of 1GW new HVDC interconnecting to the Nova Scotia / New Brunswick border and representing the injection of renewable energy and capacity from Newfoundland and Labrador and/or Quebec into the Maritimes. We also test a smaller 250MW line representing a second Maritime Link (ML2), representing a new or expanded undersea cable interconnecting Nova Scotia and Newfoundland and Labrador.

The focus of this study is on estimating the value that either of these transmission lines would provide to the downstream (Maritimes) provinces.

2.4 Report Contents

The remainder of the report is organized as follows:

+ Section 3: methodology
+ Section 4: results
+ Section 5: conclusion
+ Appendix 6: additional detail on modeling assumptions

3 Modeling Approach

3.1 Scenario Development

This study examines Atlantic Canada's electric sector resource plans under scenarios consistent with achieving deep economy wide GHG emissions reductions by 2050, with a focus on the implications of load growth on electric sector portfolio planning and the potential benefits of increased regional coordination. The load scenario modeled in this analysis is a High Electrification scenario, in which electrification of buildings and transportation end uses is assumed to occur as a key decarbonization strategy for reducing greenhouse gas emissions. This High Electrification scenario assumes electrification of most space and water heating within buildings, as well as most light-duty vehicles (LDVs) and increased adoption of electric and hydrogen technologies in medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs).

The High Electrification scenario shifts much of the decarbonization requirements onto the power sector as greater amounts of direct energy use are electrified. This generates load inputs which are fed into the electric sector capacity expansion model, which estimates a least cost generation portfolio to meet loads reliably under increasingly stringent carbon constraints. This electric sector modeling is performed under a variety of sensitivities around resource availability and cost, as described in Section 3.4.4. While low-carbon fuels are not yet commercialized, they may be an important strategy to decarbonizing harder-to-abate emissions in deep decarbonization pathways. However, for the purpose of this study we do not focus on a high fuels scenario, focusing on a high electrification scenario with variation in electric sector supply constraints to flesh out the electric sector planning paradigm more fully.

3.2 Modeling Framework

This study utilizes two E3 models – PATHWAYS and RESOLVE – which have been used extensively by governmental agencies, utilities, and regulators across the U.S. and in Canada to study deep decarbonization topics. The PATHWAYS model is used to develop economy-wide GHG emission scenarios in Atlantic Canada. The resulting electric sector loads and GHG targets are then used in the electricity-specific RESOLVE model. RESOLVE is a capacity expansion model that optimizes generation and transmission investments subject to reliability, technical, and policy constraints.

3.3 Atlantic Provinces PATHWAYS Model

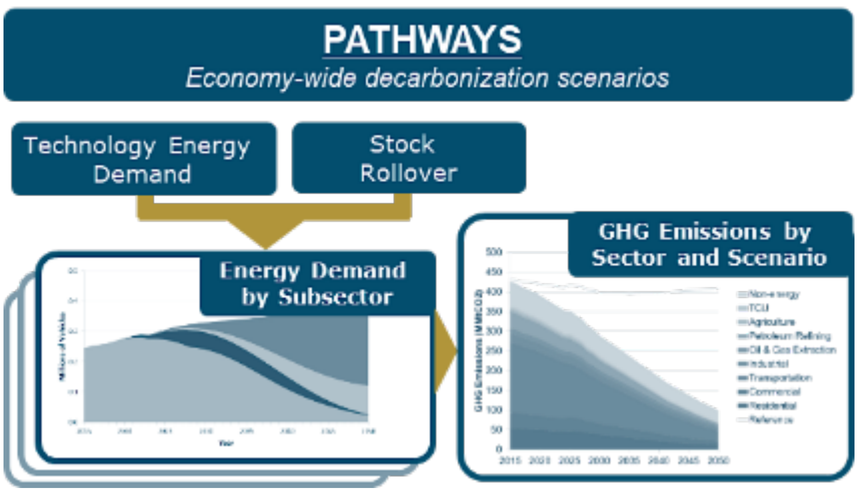
3.3.1 Overview

The Atlantic Provinces PATHWAYS model is an economy-wide representation of infrastructure, energy use, and emissions within the Atlantic Canada region. The PATHWAYS model represents the infrastructure, energy demands, and emissions for each province within the Atlantic region and forecasts emissions out to 2050. E3 originally developed the PATHWAYS framework in 2008 to help policymakers, businesses, and other stakeholders analyze trajectories to achieving deep decarbonization of the economy, and the model has since been improved over time in projects analyzing jurisdictions across North America. Recent examples include working with the California Energy Commission, NYSERDA in New York, Xcel Energy in Minnesota, and Nova Scotia Power in Nova Scotia.

We defined the greenhouse gas emissions that the region is responsible for by aligning with emissions data consistent with the federal GHG emissions accounting framework. This emissions accounting framework is broadly consistent with Intergovernmental Panel on Climate Change (IPCC) guidelines; in brief, emissions associated with energy use in residential and commercial buildings, transportation, and industry; electricity generation within the region; and non-combustion emissions associated with industrial processes, agriculture, and waste processing. Note that while the modeling framework includes provincial greenhouse gas emissions, for the purpose of this analysis we use a regional greenhouse gas emissions cap instead of modeling individual provincial targets. This was done because not all provinces have legislative midcentury targets and there is still uncertainty around how emissions trading, especially for electric power, might be defined by provinces once such targets are set. Since this analysis was meant to show the potential regional benefits of coordination, especially in electric sector planning, we focus on changes in regional emissions, although note that a more detailed analysis, especially for benefits in each province, would require simulating both individual provincial policies and individual provincial caps.

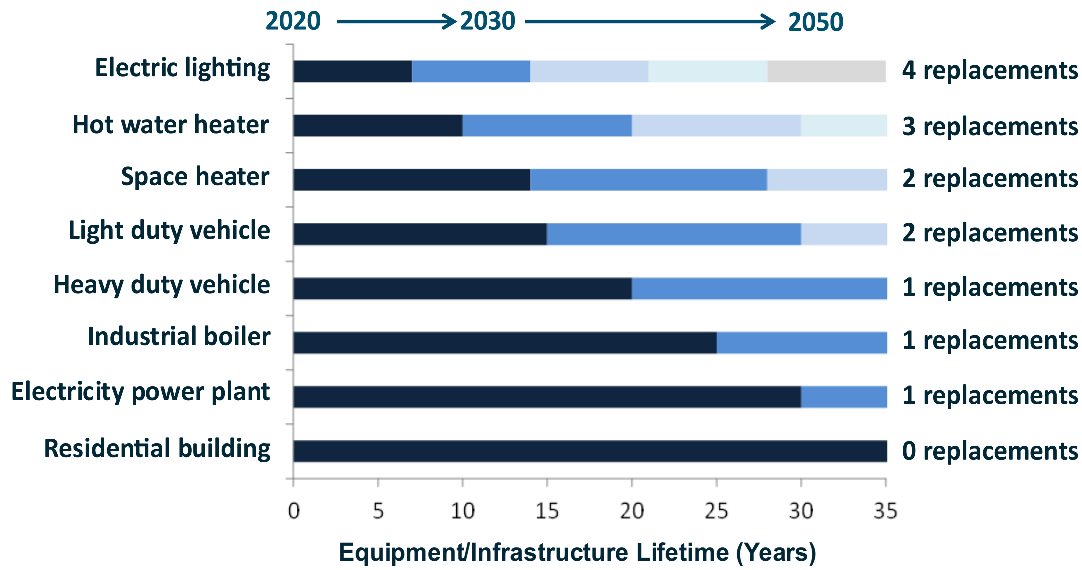
We model energy-related emissions sources and project energy demand and economy-wide emissions through 2050. In this study, PATHWAYS includes a calculation of direct energy use and emissions associated with direct energy use; the emissions associated with electricity generation are tracked within the RESOLVE model. PATHWAYS includes both supply and demand sectors to capture interactions between the sectors, and the focus is on comparing user-defined policy and market adoption scenarios and to track physical accounting of energy flows within all sectors of the economy.

Figure 3-1. Illustration of PATHWAYS Model Framework



A key feature of PATHWAYS is a characterization of stock rollover in major equipment categories (of focus in this analysis are building stock and transportation fleets). A stock rollover approach tracks infrastructure turnover of energy consuming devices while accounting for changes in performance, such as improved efficiency over time; this explicitly tracks the time lag between changes in annual sales of new devices and change in device stocks over time. Different technologies have different lifetimes, which are captured by this approach. For example, some technologies, such as lightbulbs, might have life spans of just a few years while others, such as building shell systems, might have lifespans at the decadal scale. Tracking technology and infrastructure lifespans informs the pace necessary to achieve economy-wide GHG targets while capturing potential path dependencies.

Figure 3-2. Illustrative Device Lifetimes for Stock Rollover Methodology in PATHWAYS



3.3.2 Key Assumptions

Table 3-1 summarizes the key measures used in constructing the High Electrification mitigation scenario within the Atlantic Provinces PATHWAYS model. This scenario assumes almost complete electrification of space and water heating, significant electrification of the light-duty and medium-duty transportation fleet, and some electrification of heavy duty trucking as well. Note that the PATHWAYS model is a stock rollover model which takes as user input key parameters such as sales share of different devices in each year. It is not an optimization model which calculates a least cost stock transition to a decarbonized future, nor is it an input-output model which estimates the effect of a specific policy such as a carbon tax. Rather it is a user-defined scenario-based modeling framework which allows a user to specify the effect of various policies on stock and energy demands.

We believe this type of modeling approach is more transparent and representative of the broad array of uncertainties which can occur in an economywide energy transition, as opposed to more granular input-output models which are more precise but may not be representative of uncertainty in long-term forecasts. In this study, we generate scenarios consistent with economy-wide carbon caps in 2050. As we understand there are proposals for federal carbon taxes in addition to supplementary policies such as electric sector carbon emissions caps and low carbon fuel standards. An input-output model which analyzes the effects of a carbon tax, for example, might generate a different suite of scenarios and results.

Table 3-1. Key Measures in High Electrification Scenario

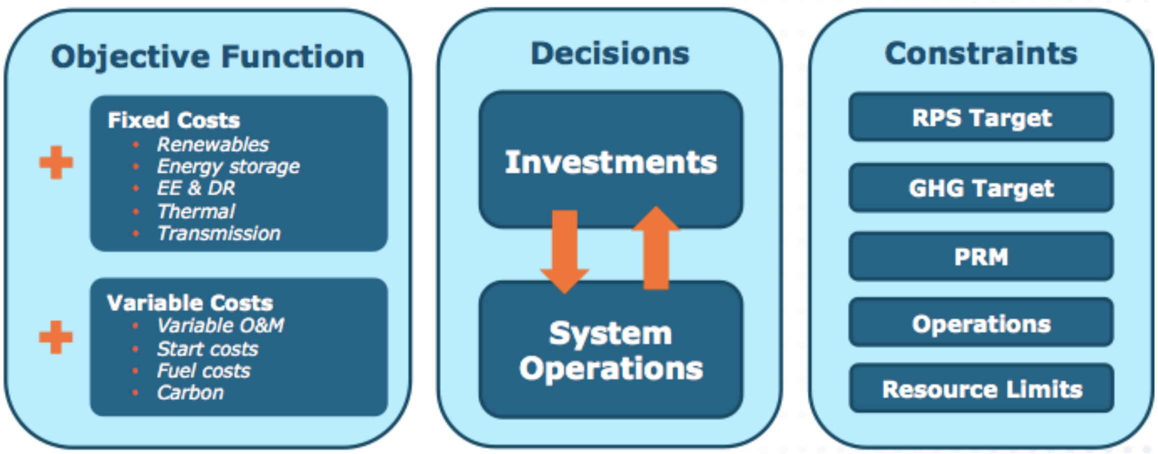
Sector	Sub-Sector	High Electrification Scenario Decarbonization Measure
Transportation	Light duty vehicles (LDV)	70% sales share by 2030; 100% by 2040
	Medium duty vehicles (MDV) and heavy duty vehicles (HDV)	MDV: 40% sales share by 2030; 100% by 2040 HDV: 20% sales share by 2030; 60% by 2040
Buildings	Building electrification	80% electric space heating sales by 2030, 100% by 2050 (with increased adoption of heat pump space heating and heat pump water heating over time)
Electricity Supply	% Zero-carbon MWh	Core scenario reaches 95% zero-carbon MWh for a regional emissions cap of 1 MMT by 2050
Others (Industry, Non-Energy and Non-Combustion, Off-road transportation)	Industrial energy use, industrial processes, agriculture, waste, aviation, shipping, etc.	These emissions assumed to be mitigated in ways which do not implicate electric sector planning as they are not likely to be electrified; decarbonization options for these could include low-carbon fuel substitution (e.g., biofuels or hydrogen) or other non-combustion mitigation measures, but since these are unlikely to implicate electric supply planning, we do not investigate these decarbonization measures in this study

3.4 Atlantic Provinces RESOLVE Model

3.4.1 Overview

RESOLVE is E3's electricity system capacity expansion model that identifies optimal long-term generation and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments vs. renewable curtailment/overbuild. The model uses weather-matched load, renewable and hydro data and simulates interconnection-wide operations over a representative set of sample days in each year. The model captures the dynamic contribution of renewable and energy storage resources to the system that vary as a function of their penetration, specifically in terms of capacity requirements toward the planning reserve margin. The objective function minimizes net present value (NPV) of electricity system costs, which is the sum of fixed investment costs and variable plus fixed operating costs, subject to various constraints. Figure 3-3 provides an overview of the model.

Figure 3-3. Overview of RESOLVE Model



RESOLVE is not designed to answer detailed resource adequacy questions in systems without sufficient firm capacity. The RESOLVE modeling framework is limited to a set of representative sample days which do not contain enough data points to make robust conclusions on reliability events that happen infrequently (potentially less than once per year). In addition, the sample days are independent (i.e., not connected) and therefore do not capture the potential need for multi-day or seasonal storage. This type of long-duration storage could be extremely important in a system without sufficient firm capacity. RESOLVE does include a Planning Reserve Margin (PRM) constraint to ensure that sufficient resources are maintained to meet an assumed long-run reliability standard, but the PRM standard is developed exogenously and incorporated into RESOLVE as an assumption. RESOLVE models operating reserve requirements but assumes that reserves can be shared across zones, which could underestimate the reserve needs faced by individual utilities within the region. Local energy and capacity needs, import scheduling, and other specific operational challenges are not modeled in detail. All these modeling treatments could result in optimized RESOLVE portfolios differing from utilities' long-term system planning.

3.4.2 Resource Options

3.4.2.1 Resource options within the region

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to technologies commercially available today. This approach ensures that the GHG reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. The full range of resource options considered by RESOLVE is shown in Table 3-2 below.

Table 3-2. Resource Options Considered in the Atlantic Provinces RESOLVE Model

Candidate Resource Option	Available Options	Functionality
Fossil Fuel Combustion Generation	• Natural gas combined cycle (CC) • Gas and oil combustion turbines (CT) • Gas CC with carbon capture and storage (CC/CCS)	• Dispatches economically based on heat rate, subject to ramping and min off/on limitations • Contributes to meeting reserve requirements and ramping needs • We assume gas turbines can burn some unspecified clean drop-in fuel (both gaseous and liquid fuels modeled in this study) at a fuel cost premium
Variable Renewable Energy	• Onshore wind • Offshore wind • Utility-scale solar PV	• Variable generation, generates as available • Can be curtailed at no cost • Constrained potential to reflect operational challenges faced by utilities in the region (except in resource-specific sensitivities) • Requires additional operating reserves • Wind contributes to meeting planning reserve requirements (at a capacity value derate)
Energy Storage	• Lithium-ion batteries (4-hour) • Compressed air energy storage (CAES, 12-hour) • Pumped hydro (12-hour)	• Stores excess energy for later dispatch • Contributes to meeting planning and operating reserve requirements
Hydro	• Hydropower, new builds and upgrades • Tidal	• Dispatches economically up to an energy budget, subject to min and max flow constraints • Contributes to meeting planning and operating reserve requirements
Nuclear	• Advanced nuclear, including small modular reactors (SMRs)	• Assumed to run at full capacity • Contributes to meeting planning reserve requirements • Model considers new nuclear power plants for New Brunswick only, consistent with utilities' long-term planning
Biomass	• Biomass • Municipal solid waste (MSW)	• Assumed to run at full capacity • Contributes to meeting planning reserve requirements • Assumed to have minimal (lifecycle) CO_2 emissions
Demand Response	• Shed demand response (DR)	• Modeled on the supply side • Used to reduce demand based on capacity and availability
Transmission	• Transmission line	• Allows model to build new transmission between New Brunswick and Prince Edward Island if needed

3.4.2.2 Low carbon energy-backed transmission resource

In addition to the resource options which the model can choose to build within the region, we run scenarios to test the value of building new transmission to connect new low-carbon resources into the Maritimes. We do not model a specific source of clean electricity which is backstopping the new clean transmission injection. Sources for such clean electricity could include allotment of existing hydro from the Hydro-Quebec system, allotment of hydro resources from Newfoundland and Labrador (such as Churchill Falls or Gull Island) transmitted through the Hydro-Quebec transmission system, or creation of new impoundments in Newfoundland and Labrador and/or Quebec.[2] Figure 3-4 below shows a schematic of the Atlantic Loop transmission concept which interconnects new resources into the Maritimes, either through an undersea cable between Newfoundland and Labrador and Nova Scotia, or through Quebec.[3]

To model these two scenarios of regional coordination, in this work we use a scenario analysis approach with sensitivities on key variables. The scenarios representing regional coordination include a high renewable energy scenario where we assume an additional 1000 MW of new transmission, backed by renewable energy from either Newfoundland and Labrador or Quebec, is injected into the New Brunswick/Quebec border, with an additional upgrade of the New Brunswick to Nova Scotia transmission system to allow an additional 500MW to flow to and from Nova Scotia. This is represented by the green arrows in Figure 3-6, below. A different scenario that was modeled is the inclusion of a smaller new transmission line, 250MW, between Nova Scotia and Newfoundland and Labrador; this represents Maritime Link 2 case with a smaller clean power injection and is represented by the blue arrow in Figure 3-6. These two transmission scenarios are modeled independently; we do not assume both transmission lines are built simultaneously in any scenario.

[2] Churchill Falls generating station is located within Labrador and is contracted through 2040. Beginning in 2041 the ownership rights to all the energy and capacity from this generating station will be allocated to the province of Newfoundland and Labrador. Energy and capacity from Churchill Falls could be a significant source of the clean energy and capacity injected into the Maritimes in this study, but since this report is agnostic as to the source of the energy and capacity we do not perform a detailed analysis of the availability of hydro within the Quebec system or the Newfoundland and Labrador system and assume as an input that the amount of hydro represented in each of the "injection" cases are available as modeled.

[3] Interim Report. Clean Power Planning Committee. August 2020. [https://www.canada.ca/content/dam/acoa-apeca/documents/Towards%20a%20Clean%20Power%20Roadmap%20for%20Atlantic%20Canada.pdf]

Figure 3-4. Schematic of Atlantic Loop transmission concept

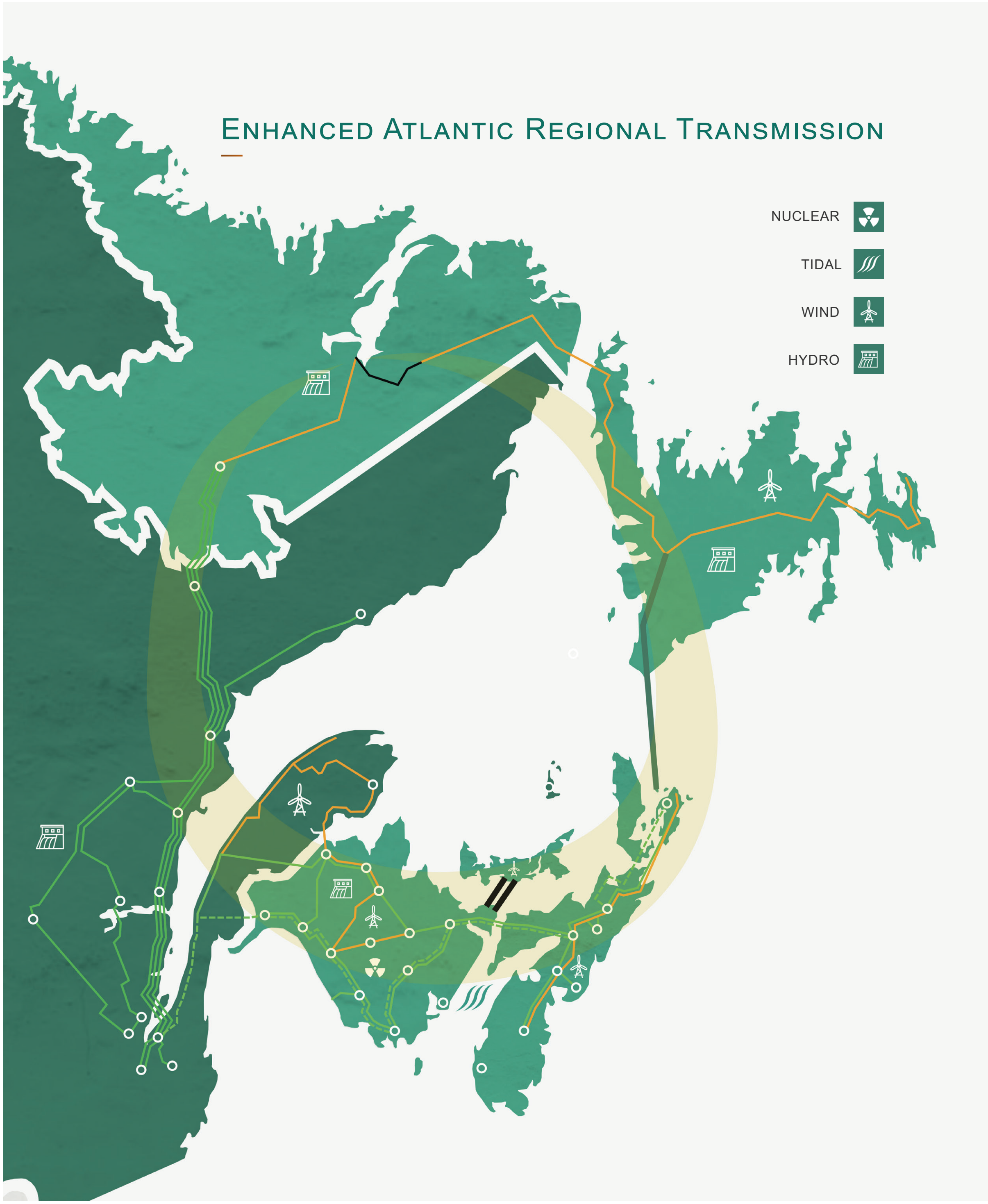
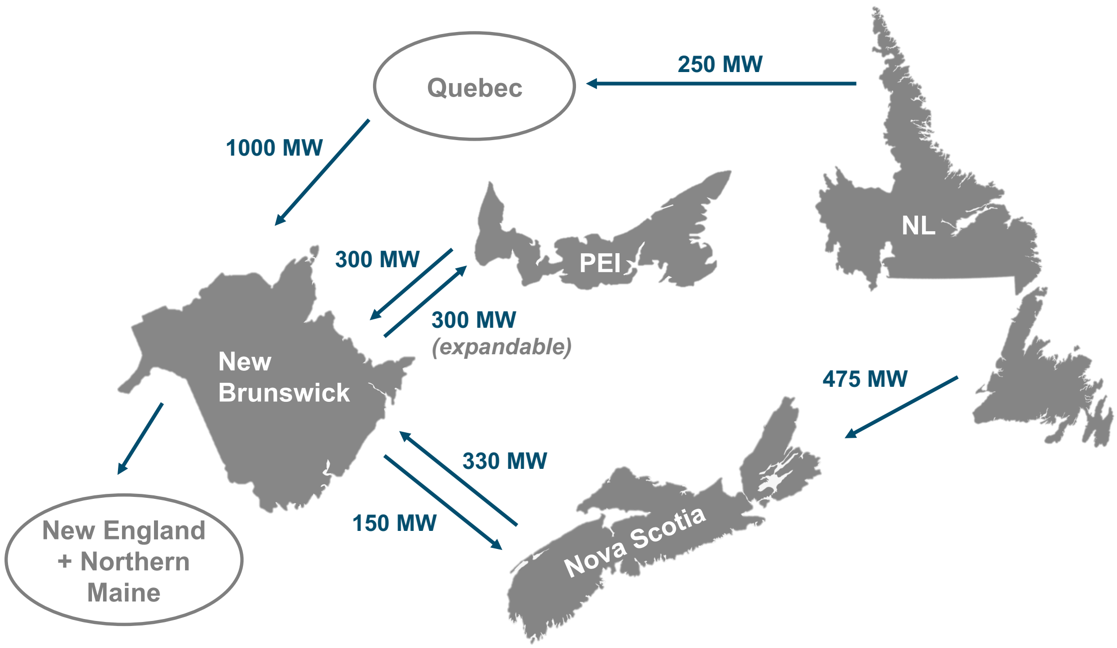


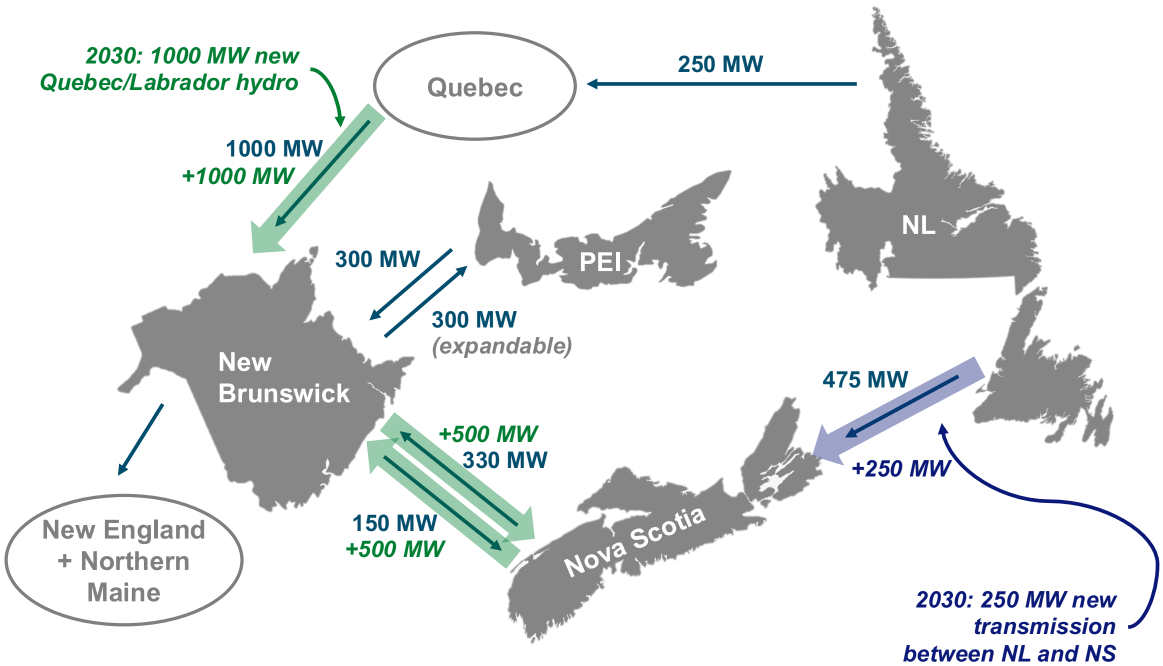
Figure 3-5. Base case (no regional coordination) electric load zones and transmission capacities modeled[4]



**Transmission constraints within each province are not modeled.*
***Exports to New England and Northern Maine (NMISA) are modeled based on 2019 levels.*

[4] Note the 250 MW link between Newfoundland and Labrador and Quebec is not representative of the physical transmission interconnection, which is over 5000 MW, but represents the amount of energy assumed to be wheeled from Newfoundland and Labrador, through Quebec, to external markets currently. We recognize the actual power flows between provinces vary from this simplified approach, but for modeling purposes this approach allows us to focus on the effects of new hydro to the Maritimes region. This new hydro could come from existing impoundments such as Churchill Falls.

Figure 3-6. Regional coordination scenarios: electric load zones and transmission capacities



*Transmission constraints within each province are not modeled.
**Exports to New England and Northern Maine (NMISA) are modeled based on 2019 levels.

To estimate the value of a renewable energy injection through either of these transmission lines, we use a scenario analysis approach where we estimate the electric supply cost of a reference scenario without the line, estimate the cost of a regional coordination scenario where new energy and capacity injection is assumed to be included for free, and take the difference between the two to estimate the gross benefits of the injected resource:

$$Value\ of\ Coordination = Cost\ of\ Reference\ Scenario - Cost\ of\ Regional\ Coordination\ Scenario$$

This modeling framework is relatively conservative as it considers benefits such as reduced fuel expense and reduced local generation capacity requirements, but does not consider other factors such as changes in congestion patterns which such an infrastructure project might deliver. See Table 3-3, below, for a summary of the benefits which are captured as well as those which are not captured in this modeling framework, but which might exist if the project were to go forward.

Table 3-3. Categories of Transmission Value

Benefit of new transmission backed by firm, low-carbon resources	Inclusion in model framework within this analysis
Product cost benefits during average conditions	Benefit quantified in this model framework
Reduced losses	
Reduced emissions	
Reduced resource investment costs	
Production cost benefits during tail conditions	Potential benefit not quantified within this analysis
Optionality – increased reliability during outages and contingencies	
Optionality – reduced production costs during outages and contingencies	
Reduced need for local reliability must run (RMR) generation	
Change to market power	
Reduced ancillary service costs	
Reduced electricity market prices	
Reduced natural gas market prices	

3.4.3 Key Assumptions

The Atlantic Provinces RESOLVE model, customized for this region as part of this study, relies on inputs and assumptions from various publicly available sources as well as discussions with technical experts within the Atlantic Clean Power Working Group. Table 3-4 provides a summary of key RESOLVE inputs. For a more detailed description of assumptions, including baseline resources, candidate resource costs, performance, and potential, refer to the inputs excel workbook corresponding to the RESOLVE model runs.[5]

[5] Full technical workbook is available upon request (available in English only). Please send a request for the workbook to nrcan.acppc-capep.rncan@canada.ca

Table 3-4. Summary of Key RESOLVE Assumptions and Scenarios

Category	Parameter	Description / Source
Area	Geographical footprint	Atlantic Provinces
	Topology	Four electrical load zones, one for each province; New England and Northern Maine modeled as external zones that import from Atlantic Provinces; see inputs Excel workbook for modeled transmission capacity between zones in base case and in change cases with new transmission capacity
Loads	Annual energy (2021–50)	PATHWAYS model results
	Peak demand (2021–50)	PATHWAYS model results
	Load profiles	Baseline load profiles provided by utilities; electrification load profiles from PATHWAYS/RESHAPE model results
	Planning reserve margin	Varies for each province based on utility inputs
GHG Reduction Policy	Power sector emissions target	Core case: 95% emissions reductions relative to 2005 levels Sensitivities: 90%, 100% emissions reductions relative to 2005 levels Carbon Tax sensitivity: no emissions reduction cap; use $170/ton [metric] carbon tax by 2030
Fuel Cost	Coal, uranium, clean drop-in fuels	E3 recommended unified values for the region based on prior work in the region
	Natural gas, oil	EIA 2020 Annual Energy Outlook for New England, based on regional similarities
	Biomass	NREL 2020 Annual Technology Baseline (ATB)
Existing Resources	Generators and imports	Utility data
Variable Renewables	Renewable potential	Reliability integration limits provided by utilities
	Renewable capacity factors	E3 recommended unified values for the region based on utility inputs
	Renewable generation profiles	Wind (onshore and offshore): CanWEA Solar: NREL
Resource Cost	Thermal, renewable, storage resources	E3 recommended unified values for the region based on NREL 2020 ATB costs, E3 WECC Survey,[6] and prior work in the region, supplemented by utility inputs
	Hydro new builds and upgrades	Utility studies[7]
Transmission Cost	Transmission cost	E3 analysis based on utility estimates[8]

[6] Generation and Transmission Resource Cost Update 2019. E3 prepared for WECC. May 15, 2019. [https://www.wecc.org/Administrative/E3-WECC Resource Cost Update-201905 RAC DS Presentation.pdf]

[7] Integrated Resource Plan, NB Power, 2017. [https://www.nbpower.com/media/772015/nb-power-2017-irp-public-english.pdf], Reliability and Resource Adequacy Study, NL Hydro, November 2018. [http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/application/From%20NLH%20%20-%20Reliability%20and%20Resource%20Adequacy%20Study%20-%20November%202018%20-%202018-11-16.PDF]

[8] P.E.I.'s underwater electric cable project officially plugged in. CEC News. August 29, 2017. [https://www.cbc.ca/news/canada/prince-edward-island/pei-electric-underwater-cable-northumberland-strait-1.4267315#:~:text=The%20project%20comprises%20two%20180,Island%20to%20mainland%20New%20Brunswick.&text=It%20spans%2017%20kilometres%20from,of%20200%20m]

3.4.4 Scenario Design

The scenarios modeled in RESOLVE are summarized in Table 3-5. Resource portfolio and cost results for key scenarios are highlighted in Sections 4.2 and 4.3. These include Core, Carbon Tax, Optimistic Resources, High Demand-Side Resources, and High Low-Carbon Baseload Cost scenarios. The Low- and High-Value Hydro scenarios are used to inform the range of gross benefits of the new transmission in Section 4.3. These are meant to represent the cost of alternatives: for example, "Low-Value Hydro" represents a scenario in which we assume alternative zero-carbon energy resources have no resource limit constraints, there is an optimistic trajectory for cost reductions of these over time, and the renewable energy injections provide no capacity value and have no flexibility. The "High-Value Hydro" sensitivity represents a scenario in which there is a high-cost trajectory for other energy resources, specifically wind, solar, and batteries. A complete set of results are provided in the study's corresponding results summary workbook.[9]

Table 3-5. Summary of RESOLVE Scenarios

Scenario	GHG Target	Transmission		
		No New Transmission (Reference)	Large Hydro + Transmission (Large Hydro)	Maritime Link 2 (ML2)
Core	95% reduction by 2050 (95x50)	• Utility resource plans • No coal by 2030	No coal by 2030	No coal by 2030
Carbon Tax	No target (with carbon tax)	No coal by 2030	No coal by 2030	
Optimistic Resource Cost/Potential	95x50	Unconstrained resource potential; low cost trajectories for wind, solar, batteries	Unconstrained resource potential; low cost trajectories for wind, solar, batteries	Unconstrained resource potential; low cost trajectories for wind, solar, batteries
High Demand-Side Resources	95x50	Additional 450 MW demand-side resources split between NS/NB/PE	Additional 450 MW demand-side resources split between NS/NB/PE	Additional 450 MW demand-side resources split between NS/NB/PE
High Low-Carbon Baseload Cost	• 95x50 • No target (with carbon tax)	50% higher low-carbon baseload costs	50% higher low-carbon baseload costs	
Reference	• No Target • 90x50 • 95x50 • 100x50	Utility resource plans		
Low-Value Hydro	• 90x50 • 95x50 • 100x50	Optimistic resource cost/potential	Optimistic resource cost/potential; no capacity value and flat shape for injected hydro	Optimistic resource cost/potential; no capacity value and flat shape for injected hydro
High-Value Hydro	• 90x50 • 95x50 • 100x50	High cost trajectories for wind, solar, batteries	High cost trajectories for wind, solar, batteries; full capacity value for injected hydro	High cost trajectories for wind, solar, batteries; full capacity value for injected hydro

[9] Full technical workbook is available upon request (available in English only). Please send a request for the workbook to nrcan.acppc-capep.rncan@canada.ca

4 Results

4.1 Economy-wide Decarbonization Pathways

This study modeled a high electrification pathway to meet an economy-wide deep decarbonization target, with direct emissions reductions of 85% across the region. This is consistent with both targets for direct emissions reductions consistent with Paris Agreement goals, as well as more recent, aggressive "net zero" emissions framing, with the assumption that remaining emissions can be addressed by direct abatement options or offsets. Figure 4-1 shows the economy-wide greenhouse gas emissions trajectory for the Atlantic Provinces region which was modeled in the High Electrification scenario. In transportation, the scenario assumes significant penetration of battery electric vehicles to decarbonize the majority of on-road transportation. In buildings, there is significant electrification of space and water heating, especially in Nova Scotia and Prince Edward Island, where electricity is not currently the dominant form of building space heating.

Figure 4-1. Regional economy-wide emissions trajectory modeled in High Electrification scenario

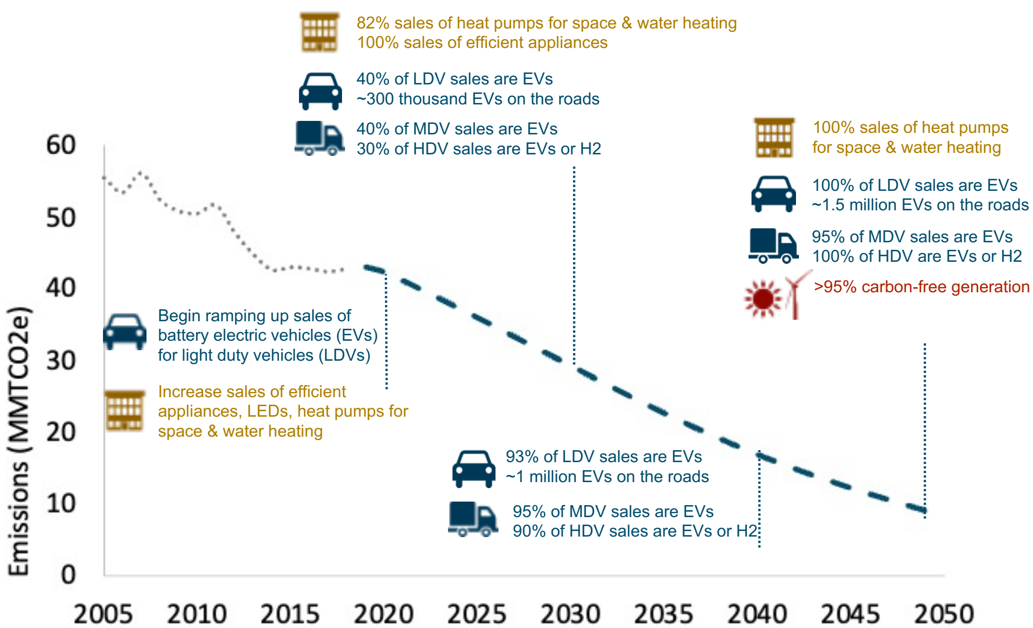


Figure 4-2 illustrates the emissions of the High Electrification by sector. This highlights the significant reductions achieved in buildings, transportation, and electricity as well as reductions in other sectors, such as industry and non-combustion agriculture; these are assumed to occur due to a variety of measures such as energy efficiency and low-carbon fuel switching or fuel substitution with hydrogen or renewable fuels. These were assumed to not be good candidates for electrification, and thus were not the focus of this study.

Figure 4-2. Reductions in Economy-wide GHG emissions by sector through 2050

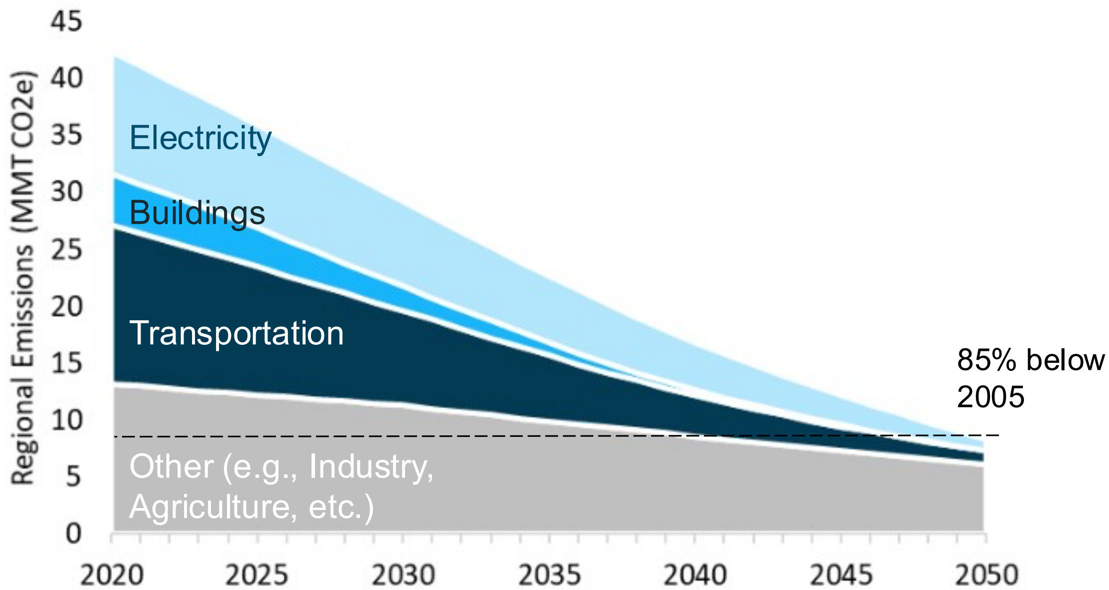


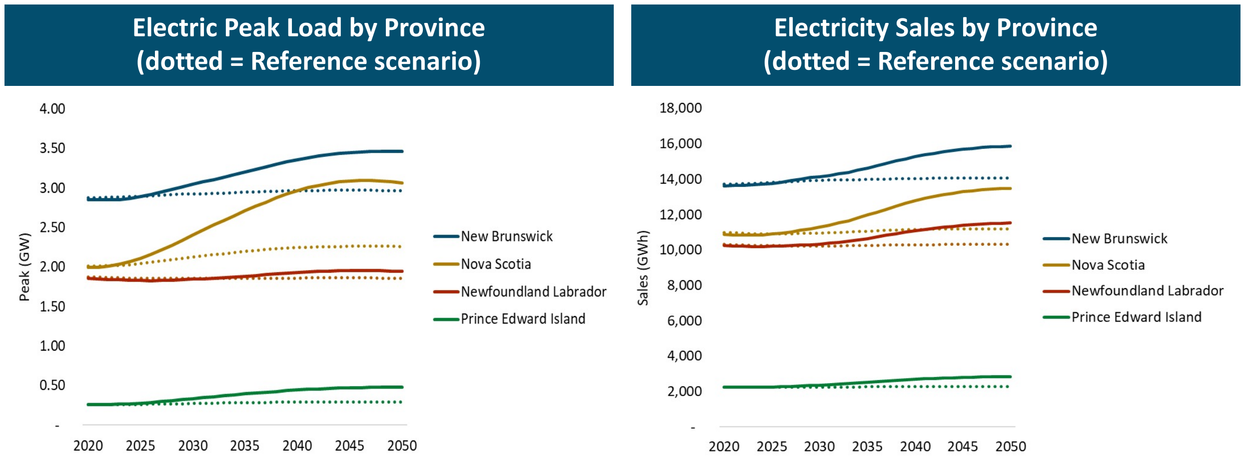
Figure 4-3. Regional Electricity Sector Emission Targets (i.e., carbon cap)

	95% by 2050 Regional Electricity Sector Emission Reductions Targets (MMT CO2e)					
	2021	2030	2035	2040	2045	2050
High Electrification	10.8	7.8	6.1	4.4	2.7	1.0

To model reductions in emissions from the electricity sector, this study assumed a regional electricity sector emissions target which reached one million metric ton of carbon dioxide equivalent in 2050. Since this study models the regional impacts of including new transmission and hydro, this carbon cap was based on a regional reduction overall, not based on individual provincial carbon caps. This means that the modeling does not attempt to capture four individual carbon caps for each of the Atlantic Canada provinces, but models a single cap across the region, implicitly allowing for trading of emissions within the region. We recognize this is a simplification but for the purposes of estimating the potential regional benefits of expanded transmission and coordination, we felt this simplification was appropriate.

Growth in electric loads and electric peak demand is shown in Figure 4-4. Substantial energy efficiency mitigates the increase in electricity use from existing uses, but overall electricity use grows significantly due to electrification of end uses in transportation and buildings. Continued electrification of space heating causes significant winter peak load increases, although our model measures very efficient cold climate heat pumps and does not consider extreme 1-in-10 style weather events in this peak forecast. Similarly, while some transportation charging load contributes to peak our model also includes significant load flexibility from transportation loads to reflect the potential for managed charging or even advanced vehicle to grid systems to mitigate some of the coincident peak effects of vehicle charging. A more detailed load shaping approach, not undertaken in this study, would require taking into consideration existing and future planned rate structures, availability of more sophisticated metering infrastructure such as smart meters and multi-way power flow, and consideration of multiple weather years.

Figure 4-4. Modeled Load Growth by Scenario



4.2 Electricity Generation Portfolios

RESOLVE develops least-cost electric system resource portfolios to serve projected electric load and meet the electricity sector carbon caps defined in Section 4.1. The model chooses a diverse mix of resources given operating constraints, transmission costs, and the economic and reliability value of having a technologically and geographically diverse set of resources. We have run the model under a variety of different assumptions surrounding the availability and cost of various resources.

Since this study focuses on the potential benefits of expanded regional coordination, when presenting results we compare the value of the hydro plus transmission project between each case; we do not focus on the resource builds without the transmission line or compare those across the different sensitivities, as that is not the focus of the research question at hand. The results section includes graphical representation of key results. A complete set of results are provided in the study's corresponding results summary workbook.[10]

4.2.1 Core Scenarios

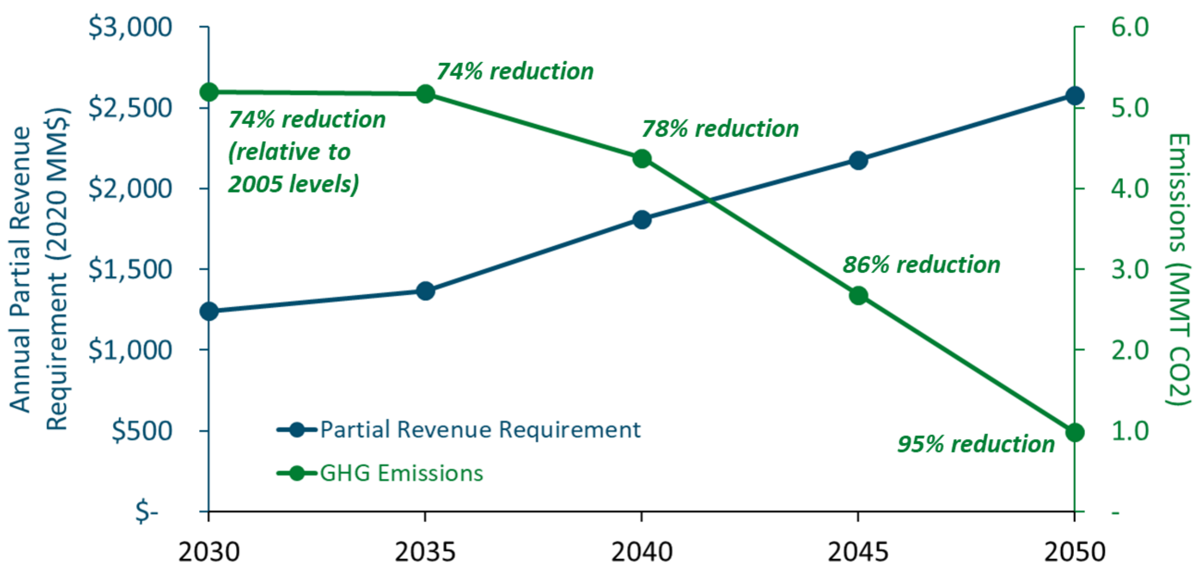
4.2.1.1 Reference Case

Figure 4-5 shows the cost and GHG emission trajectories for the electricity sector for the Atlantic Provinces in the 95% GHG reductions by 2050 (95x50) Reference case. Because of the hydro and wind resources already available to the region, the Reference case electricity generation portfolio is relative clean, reaching 74% emissions reduction by 2030 (relative to 2005 levels). As the GHG target becomes more stringent in later years, the cost for the resource portfolio to meet the GHG target while maintaining system reliability increases. Note this graphic includes some, but not all, of the costs associated with the electricity system so we call this cost metric a partial revenue requirement. This includes costs for new generators built in addition to those currently on the system and includes cost to purchase fuel for existing and new generators, but it does not include the cost for maintaining existing generation and transmission; it does not include the cost for distribution system upgrades necessary to meet growing loads; it does not include cost of corporate facilities.

[10] Full technical workbook is available upon request (available in English only). Please send a request for the workbook to nrcan.acppc-capep.rncan@canada.ca

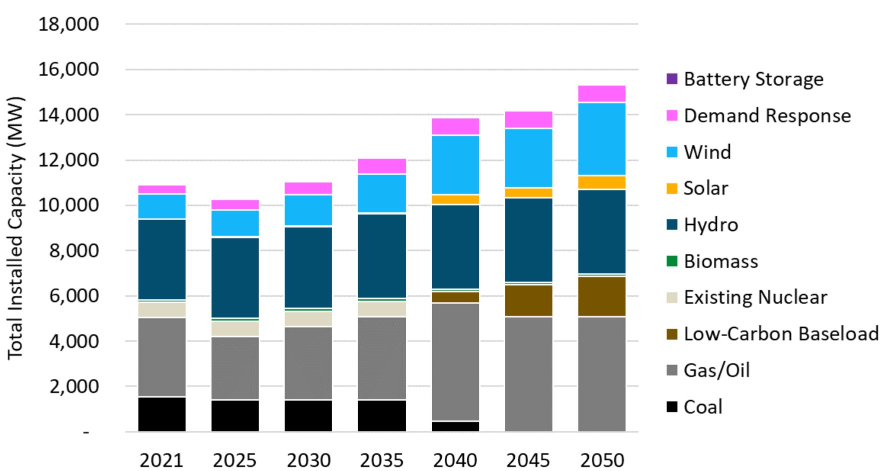
The electricity generation portfolio in the Reference case under the 95x50 GHG target is shown in Figure 4-6. The region builds new wind, hydro, and solar resources throughout the modeling period. In later years, low-carbon baseload generators are built, driven by the need to meet increasingly stringent GHG targets under resource potential constraints, as well as the need for load-following resources to maintain grid stability. These low-carbon baseload resources (such as advanced nuclear or carbon capture and storage) are necessary to maintain system reliability, provide firm capacity, and assist in integrating renewable resources onto the system, but they are relatively more risky technology options as they are less mature resources.

Figure 4-5. Annual Partial Revenue Requirement and GHG Emissions Trajectories in the Reference Case under 95x50 GHG Target



Annual costs include costs of new resource buildout (capital cost, fixed operating and maintenance costs) and ongoing fuel and operating costs.

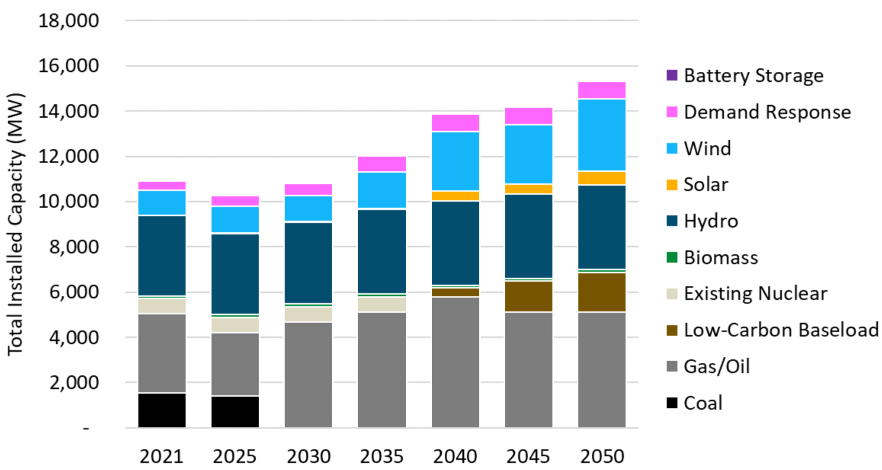
Figure 4-6. Total Installed Capacity in the Reference Case under 95x50 GHG Target



4.2.1.2 Reference Case with No Coal by 2030

Figure 4-7 shows the 95x50 Reference case with all coal retired by 2030. By comparing Figure 4-6 and Figure 4-7 we see that between 2030 and 2040, additional natural gas resources are built to make up for the retiring coal capacity, because the region still needs new generation resources to meet both capacity and energy requirements. This resulted in minimal differences in total capacity between the two Reference cases.

Figure 4-7. Total Installed Capacity in the Reference Case with Coal Retirement by 2030 and 95x50 GHG Target



4.2.1.3 Regional Coordination core case results (large hydro, large hydro with no coal by 2030, and Maritime Link 2)

Figure 4-8, Figure 4-9, and Figure 4-10 compare the generation portfolios between the Reference and Regional Coordination cases for three 95x50 scenarios: Large Hydro scenario (Figure 4-8), Large Hydro with No Coal by 2030 scenario (same injection case as the Large Hydro scenario but alternative Reference case with all coal retired by 2030, Figure 4-9), and Maritime Link 2 (Figure 4-10). In all these scenarios, the new transmission line and associated clean energy displaces or defers local firm capacity (thermal resources in earlier years, low-carbon baseload in later years) and some variable renewable resources.

Figure 4-8. Total Installed Capacity in the Core 95x50 Scenario (Reference and Large Hydro Cases)

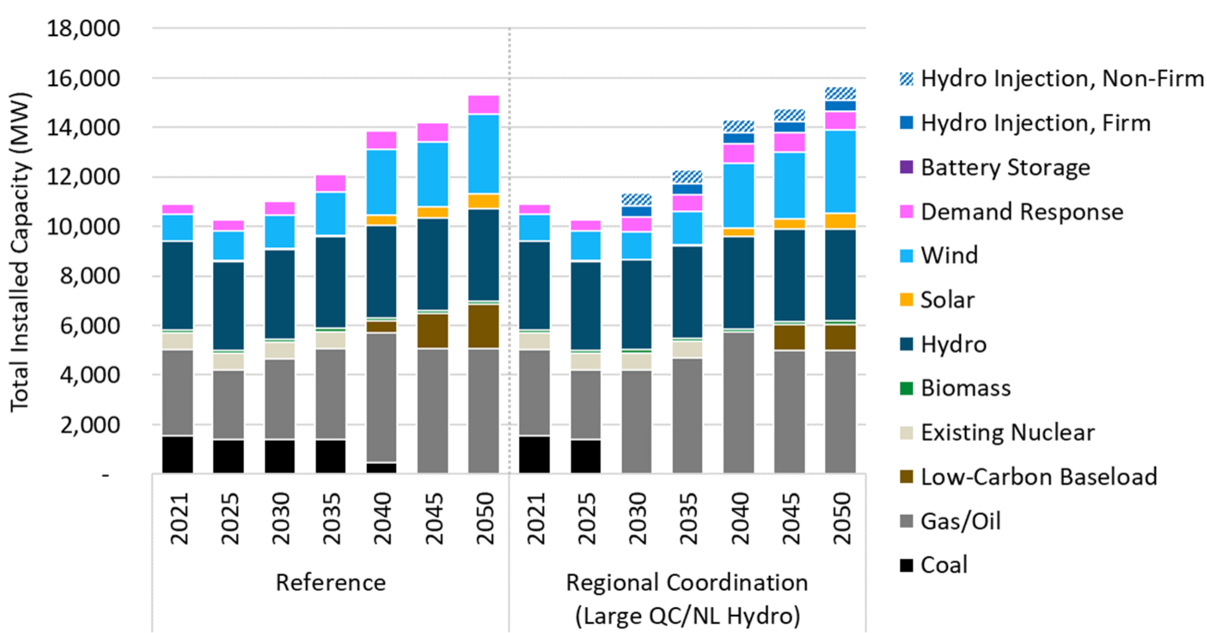


Figure 4-9. Total Installed Capacity in the No-Coal 95x50 Scenario (Coal Retirement Reference and Large Hydro Cases)

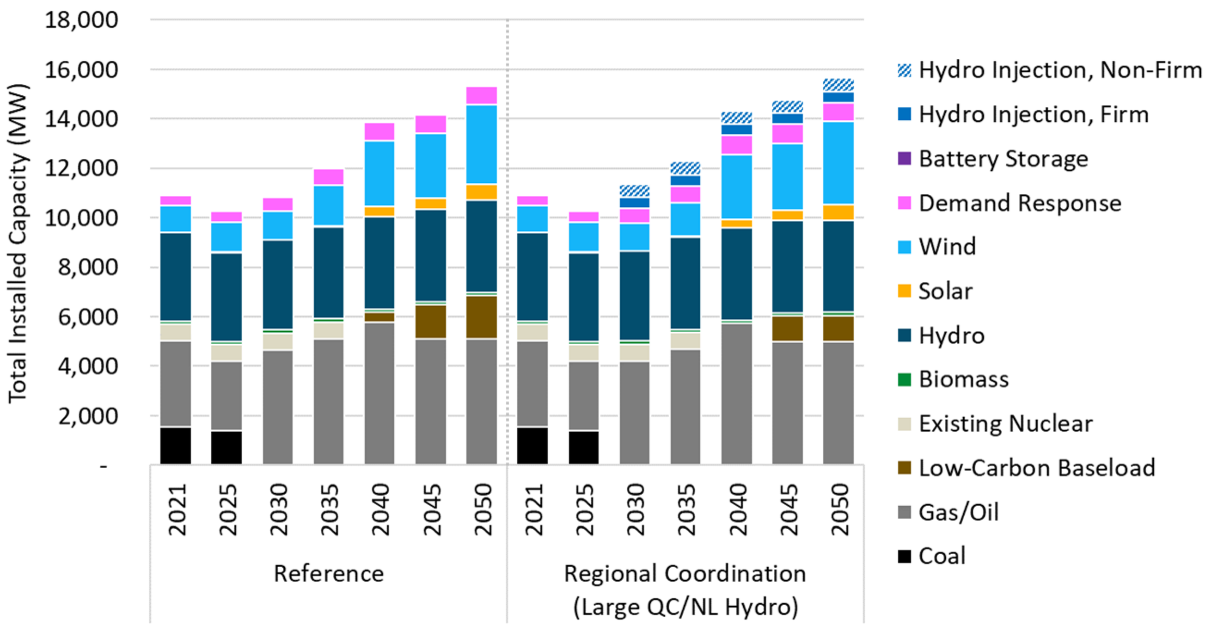
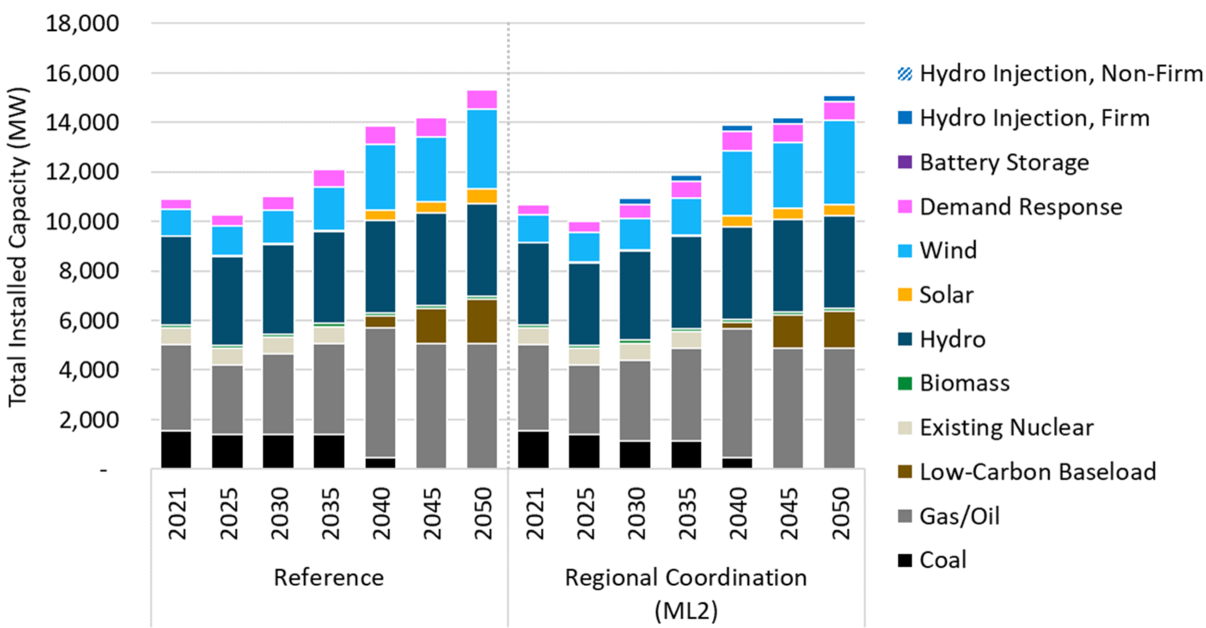


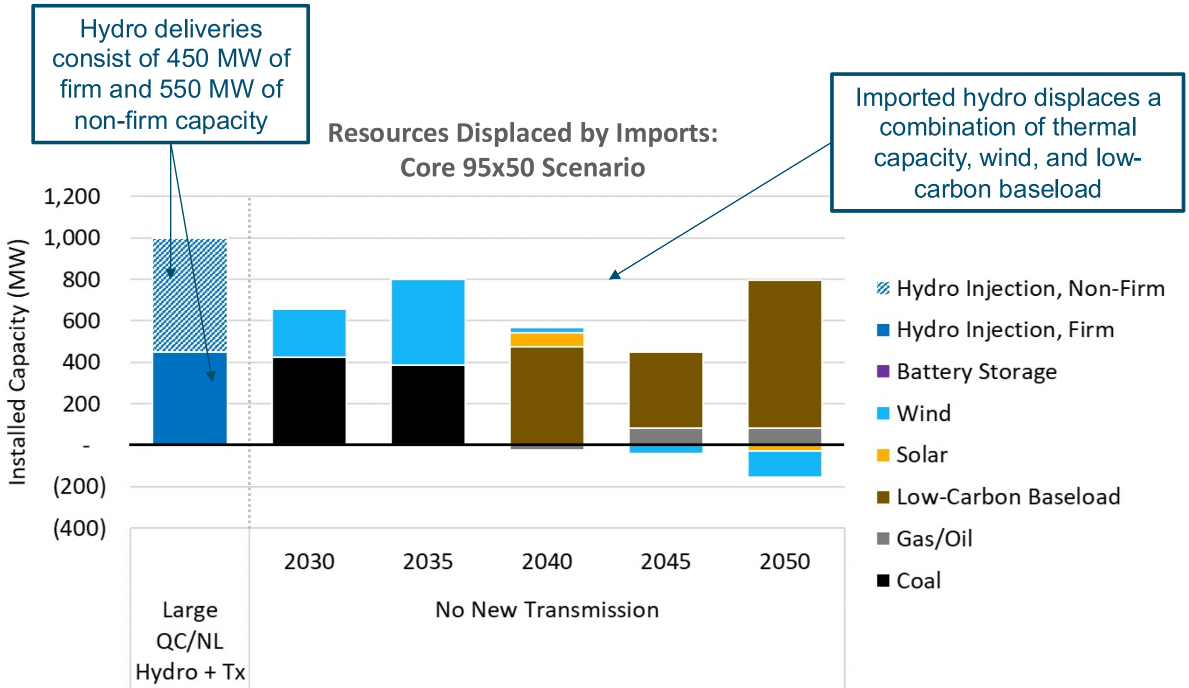
Figure 4-10. Total Installed Capacity in the Core 95x50 Scenario (Reference and ML2 Cases)



Changes in generation portfolio brought by the new hydro can be further seen in Figure 4-11, Figure 4-12, and Figure 4-13, which show the injected hydro capacity on the left side, and capacity displaced by the injected hydro on the right side, for the three scenarios. Note that in all these scenarios, more wind and solar resources are built in the Regional Coordination case than in the Reference case in later years, shown as negative capacity on the right side of the figures. This is because the new hydro (Large Hydro or ML2) provides some firm capacity, which lowers the overall need for capacity in the region. As a result, resources that can provide low-cost energy but have a lower or zero capacity value (wind and solar in this case), become more economic. Flexible hydro imports can also complement variable renewable generation to some extent, effectively acting as additional energy storage. Please note the modeling framework here, in particular the decision to ignore the cost of energy and transmission associated with the renewable energy injection, is meant to illustrate the gross benefit that the injection could provide. In Section 4.3 we discuss the gross benefits and provide some sense of scale for how these gross benefits might compare to potential cost of energy and transmission.

Key takeaways from Figure 4-11 and Figure 4-12 are that the new hydro displaces a significant amount of fossil fuel capacity, whether coal or natural gas, in the early years, but displaces primarily low-carbon baseload in the later years. This is because under the 95% carbon constraint the region needs a source of firm, low-carbon capacity as well as energy and in the absence of the new transmission line and associated clean energy the model picks new firm low-carbon baseload to fill that gap. A key finding is that the large new hydro does not compete with wind and solar in the later years.

Figure 4-11. Capacity Displaced by New Hydro and Transmission in the Core 95x50 Scenario (Reference and Large Hydro Cases)



Effective coal capacity displaced is net of gas capacity built due to coal retirement; coal is not retired in the reference (no new transmission) case

Figure 4-12. Capacity Displaced by New Hydro and Transmission in the No-Coal 95x50 Scenario (Coal Retirement Reference and Large Hydro Cases)

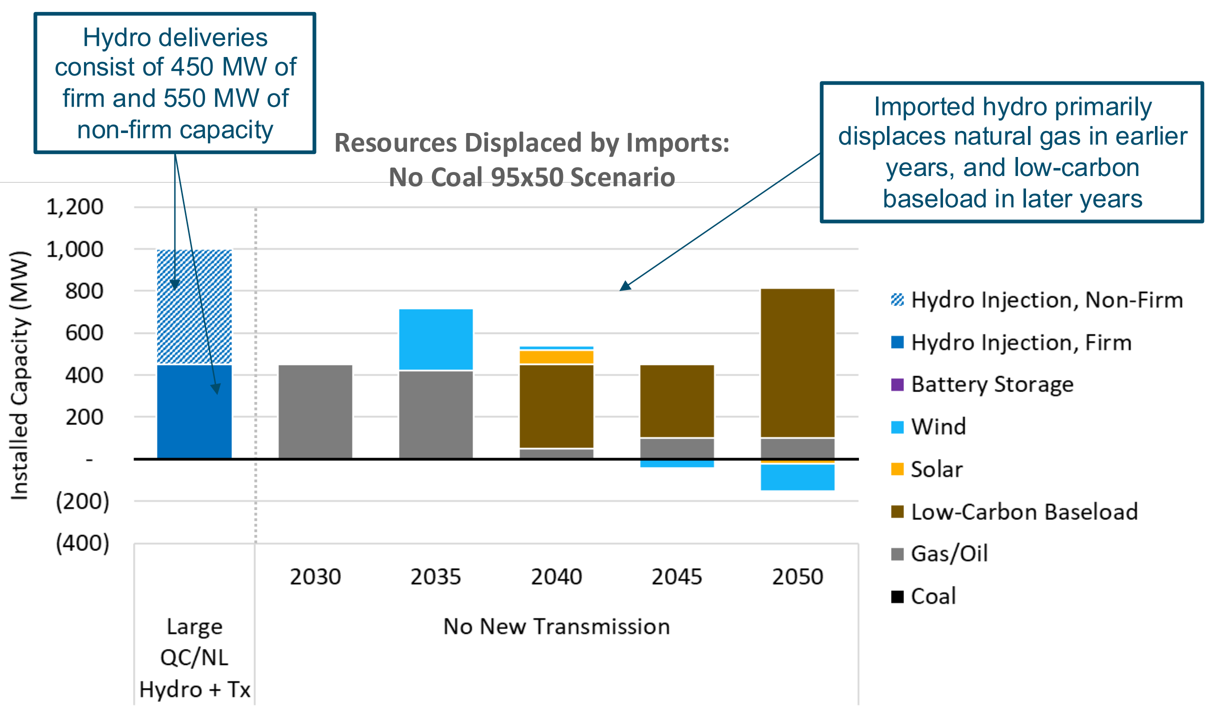
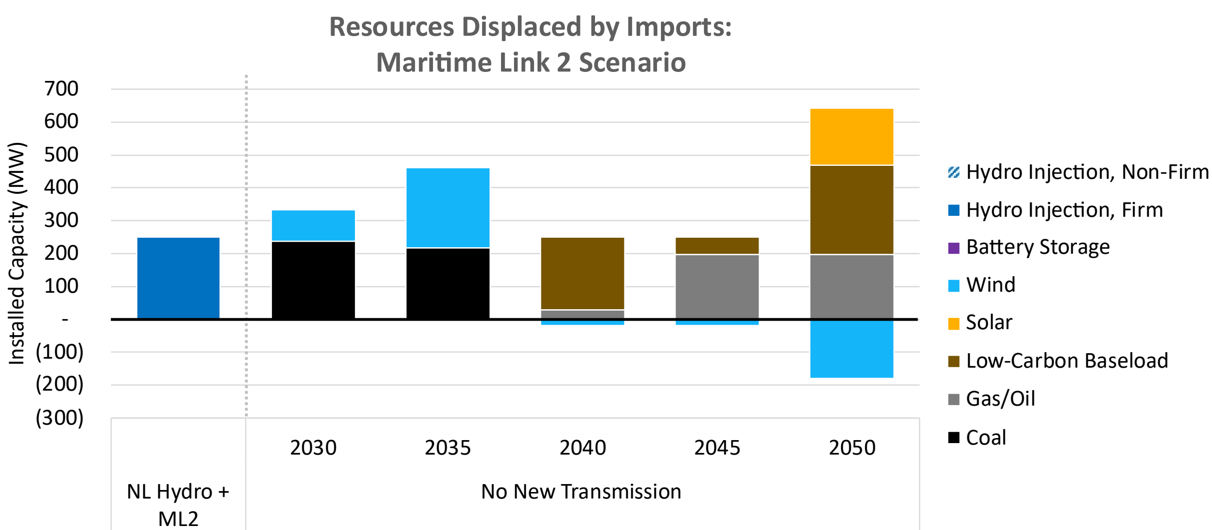


Figure 4-13 is focused on the Maritime Link 2 case, which shows a similar story in the early years; access to a second Maritime Link would enable Nova Scotia to replace coal capacity and some wind resource build. In the later years the second Maritime Link enables Nova Scotia to avoid building new firm low-carbon resources, as well as some gas and solar. Maritime Link 2 displaces both gas and oil for firm capacity, as well as the low-carbon baseload and solar for energy resources; since it also acts flexibly it allows the region to build more wind in Newfoundland and Labrador, which is used to export over the tie and displaces solar build in Nova Scotia. Note that the Maritime Link 2 case assumes that the new large scale transmission project interconnecting New Brunswick, Nova Scotia, and Quebec is not built but it does assume that an expanded reliability tie-line between New Brunswick and Nova Scotia is included (this tie-line is assumed to be included in all scenarios, including the Reference scenarios, as it is needed for reliability purposes to enable increased wind build in the Maritimes region). Thus, the Maritime Link 2 scenario does have some knock on effects on resource build in New Brunswick, but the majority of the changes in resource build happen in Newfoundland and Labrador and Nova Scotia.

Figure 4-13. Capacity Displaced by New Hydro and Transmission in the Core 95x50 Scenario (Reference and ML2 Cases)



4.2.2 Sensitivity scenarios

To further characterize the changes in resource build, we ran the Large Hydro sensitivities on key variables, including a scenario with higher demand response assumed as a resource option; a scenario with optimistic renewable resource potential (lower cost for wind and no limit on how much wind can be integrated); a scenario in which we implement a higher low-carbon baseload asset cost; and a scenario in which a carbon *tax*, rather than a strict carbon *cap*, was implemented.

4.2.2.1 High DR case

Figure 4-14 and Figure 4-15 show the total installed capacity and capacity displaced by the new hydro for the High Demand Response (DR) sensitivity scenario. We modeled demand resources as a firm capacity resource, meaning they reduce annual peak but do not reduce annual energy requirement overall. The higher DR mostly reduces higher gas builds compared to the Core 95x50 scenario (Figure 4-8). The higher DR also lowers overall capacity needs in the region, making wind more economic relative to gas generation as a primary energy resource. This explains the higher wind capacity displaced in Figure 4-15 compared to the Core 95x50 scenario (Figure 4-11). Note the increased DR resource was assumed to exist for no cost, and thus the results show what the value of this level of DR resource would be to the system but do not speak to the cost of obtaining such a resource.

Figure 4-14. Total Installed Capacity in the High DR 95x50 Scenario (Reference and Large Hydro Cases)

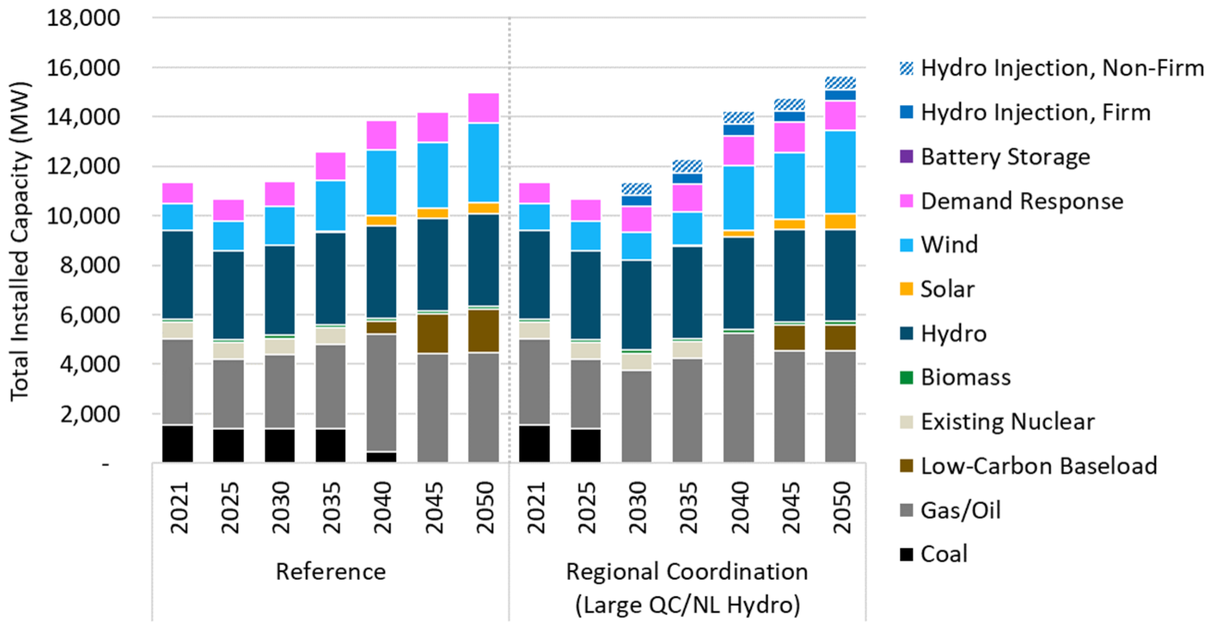
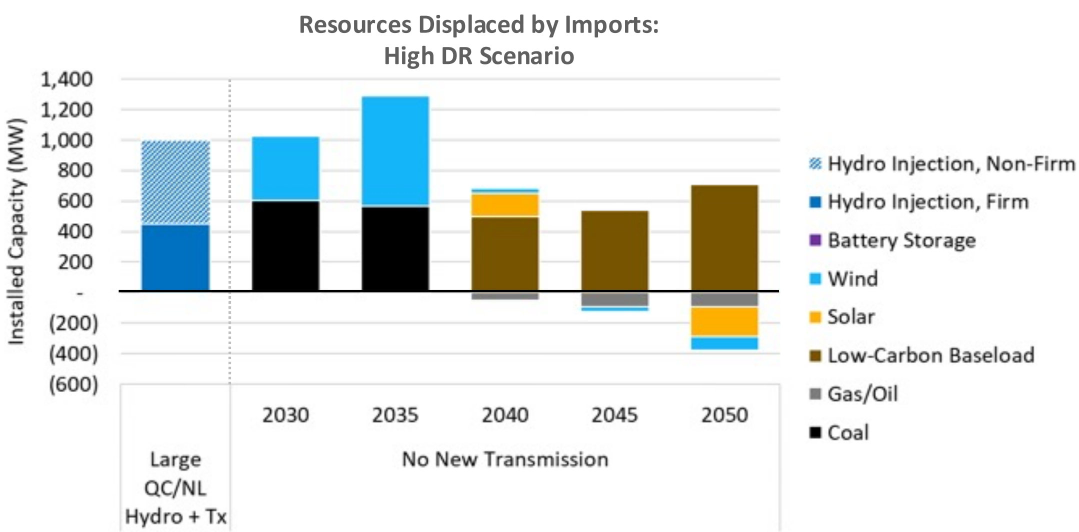


Figure 4-15. Capacity Displaced by New Hydro and Transmission in the High DR 95x50 Scenario (Reference and Large Hydro Cases)



Effective coal capacity displaced is net of gas capacity built due to coal retirement; coal is not retired in the reference (no new transmission) case

4.2.2.2 Optimistic resource cost/potential

Figure 4-16 and Figure 4-17 show the total installed capacity and capacity displaced by the new hydro for the Optimistic Resource Cost/Potential sensitivity scenario. Figure 4-16 shows that when lower costs trajectories are assumed for wind, solar, and batteries, and resource potential is unconstrained (i.e., we assume no limit to how much new wind, solar, and batteries the utilities can integrate into their systems), the model chose to build about 2800 MW solar, 5200 MW wind, and 860 MW of batteries in the Reference case. Up to about 1500 MW of wind was displaced by the large hydro injection by 2050, as shown in Figure 4-17. Evaluating the technical potential of, and system requirements associated with, integrating these levels of variable generation resources in the Atlantic Region was outside the scope of this study.

Figure 4-16. Total Installed Capacity in the Optimistic Resource Cost/Potential 95x50 Scenario (Reference and Large Hydro Cases)

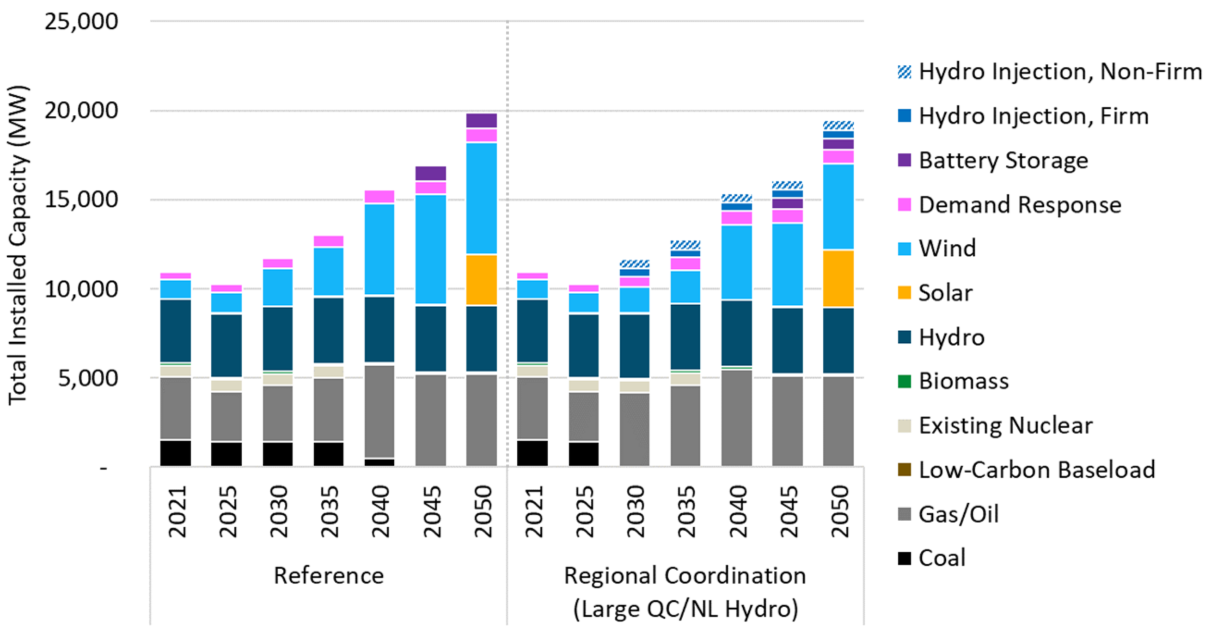
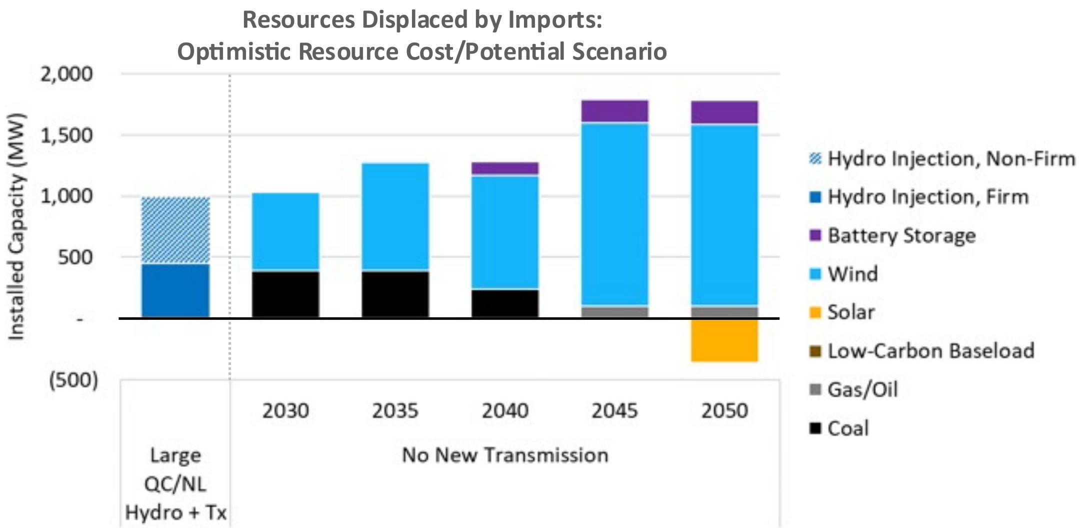


Figure 4-17. Capacity Displaced by New Hydro and Transmission in the Optimistic Resource Cost/Potential 95x50 Scenario (Reference and Large Hydro Cases)

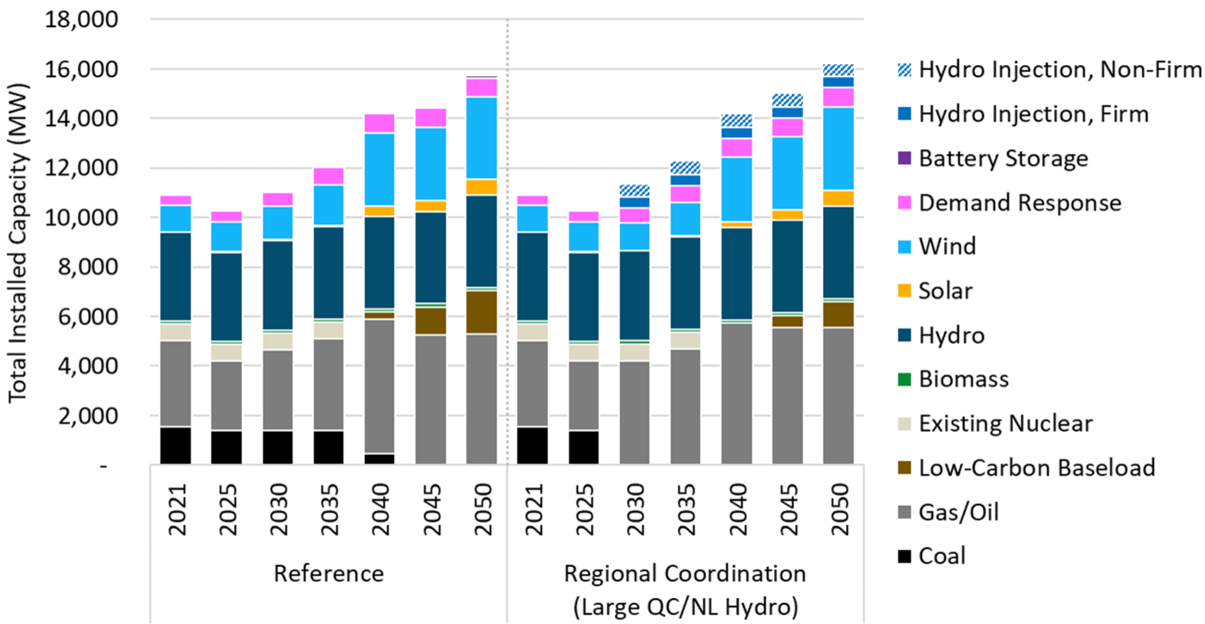


Effective coal capacity displaced is net of gas capacity built due to coal retirement;
coal is not retired in the reference (no new transmission) case

4.2.2.3 High low-carbon baseload cost

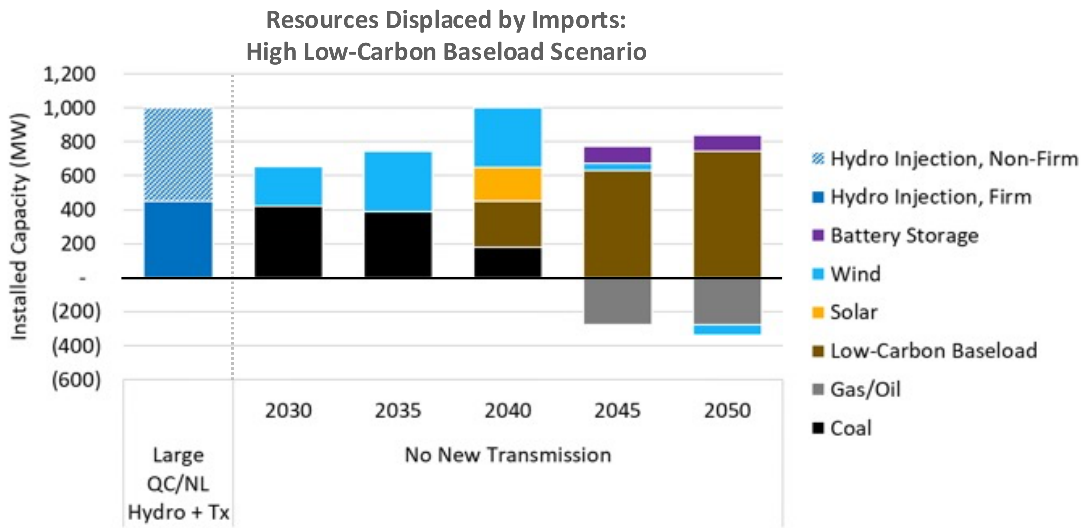
To test the sensitivity of the capacity results to different costs for low-carbon baseload resources, we ran a scenario assuming higher costs for low-carbon baseload resources (nuclear and natural gas with CCS in this study); changing these resource costs led to small changes in the generation portfolio under a 95x50 GHG target, as seen by comparing Figure 4-18 and Figure 4-8 (Core 95x50). Under a stringent GHG target, as renewables approach their potential limits, low-carbon baseload resources become the most economic resources for meeting the GHG target and for providing energy and capacity in the region, even at higher costs.

Figure 4-18. Total Installed Capacity in the High Low-Carbon Baseload Cost Scenario (Reference and Large Hydro Cases)



As shown in Figure 4-19, when low-carbon baseload costs are higher, more renewable resources are built compared to the Core reference case (Figure 4-11), which then get displaced by the new transmission line and associated clean energy. When the new hydro is available, more gas resources are built in the *injection case* compared to the reference case. This is because when low-carbon baseload is more expensive, the model chooses to build more gas for both capacity and energy to the extent that the GHG target allows. Additional clean energy from the new hydro displaces energy from natural gas combined cycles, and more gas combustion turbines can be built economically for capacity lowering overall system costs without significantly contributing to system emissions.

Figure 4-19. Capacity Displaced by New Hydro and Transmission in the High Low-Carbon Baseload Cost Scenario (Reference and Large Hydro Cases)



Effective coal capacity displaced is net of gas capacity built due to coal retirement; coal is not retired in the reference (no new transmission) case

4.2.2.4 Carbon tax

Under all prior scenarios, the carbon constraint within the region was a strict carbon cap. As an alternative to a carbon cap, we ran a scenario implementing a carbon tax across the fuels within the region. To estimate the impact of a rising carbon tax consistent with the federal climate plan (reaching $170/ton by 2030) proposed in December 2020,[11] we assumed the output-based standards for solid, liquid, and gaseous fuels remained as specified in Part 36.1 (2) and Schedule 1,[12] and a per ton carbon price was implemented. This carbon tax multiplies the tax rate ($/ton) by the total production (GWh) of each resource and by the difference between its emissions intensity and the output based standard.

The tax rate is provided in Figure 4-20 and the output-based emissions standard (OBPS) by fuel type is provided in Figure 4-21.[13] Note the federal OBPS specifies different limits for new gas and existing gas generators but because of data and modeling limitations in this round of analysis we applied the federal limits for new gas generators for all gas fired generator facilities. This means that we may be over-estimating the impact of the carbon tax as we are applying a more stringent gas limit on existing gas generators than what the federal OBPS requires.

$$Carbon\ Tax = Tax\ Rate\left(\frac{\$}{ton}\right) * ElectricityProduction\ (GWh)$$
$$* \left(CarbonEmissionsIntensity\left(\frac{tons}{GWh}\right) - OutputBasedStandard\left(\frac{tons}{GWh}\right)\right)$$

---

[11] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf

[12] https://laws-lois.justice.gc.ca/PDF/SOR-2019-266.pdf

[13] Note tons here refer to metric tons

Figure 4-20. Carbon Price as Applied in Carbon Tax Sensitivity

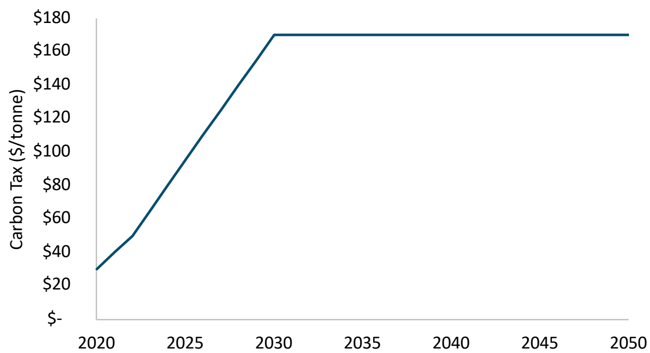


Figure 4-21. Output Based Emissions Standard Assumed for Carbon Tax Sensitivity

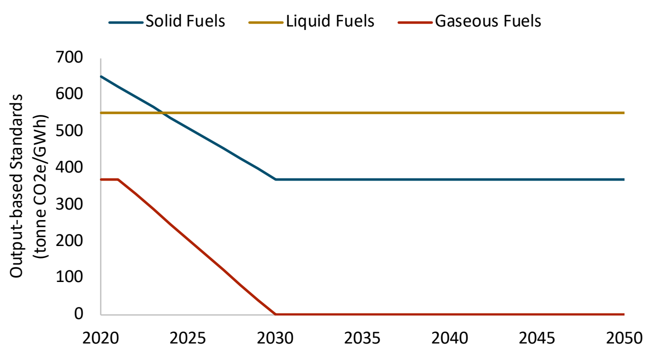


Figure 4-22 shows the GHG trajectories for the Reference case in the two Carbon Tax scenarios modeled: one assuming base-case resource potential and costs, one assuming higher costs for low-carbon baseload resources. The 95x50 Reference case and several GHG carbon cap targets are also shown for comparison. Please note that the Reference case in the carbon tax scenario also assumes all coal is offline by 2030, to be consistent with an assumed broader federal target of eliminating coal in electricity generation.

As shown in Figure 4-22, carbon tax serves as a more stringent GHG constraint than the 95x50 target in earlier years but is less effective in reducing emissions than the 95x50 target in later years. At base-case resource costs, the region could achieve 87% GHG reductions by 2050 (relative to 2005 levels) under the new carbon tax schedule. When low-carbon baseload costs are assumed to be 50% higher, the region could only achieve 73% GHG reductions by 2050. This indicates that when resource options are more constrained (in this case due to the higher costs), relying on gas resources and paying for the price of carbon could be a more economical alternative, even with a high $170/ton carbon price.

This observation can be further seen in the resource build results in Figure 4-23 and Figure 4-24 for the base-case Carbon Tax scenario, and in Figure 4-25 and Figure 4-26 for the Carbon Tax scenario with high low-carbon baseload costs. Compared to the Core 95x50 scenario (Figure 4-8), Figure 4-23 shows that more wind is built in earlier years for energy, and more gas is built in later years as a cheaper capacity resource than low-carbon baseload. Low-carbon baseload resources are still built for generation to lower carbon tax payments. Figure 4-24 shows that consistent with the total capacity results, less low-carbon baseload is displaced by the new hydro than in the Core 95x50 case (Figure 4-11).

Figure 4-22. GHG Emissions in the 95x50 and Carbon Tax Reference Cases Compared to GHG Targets

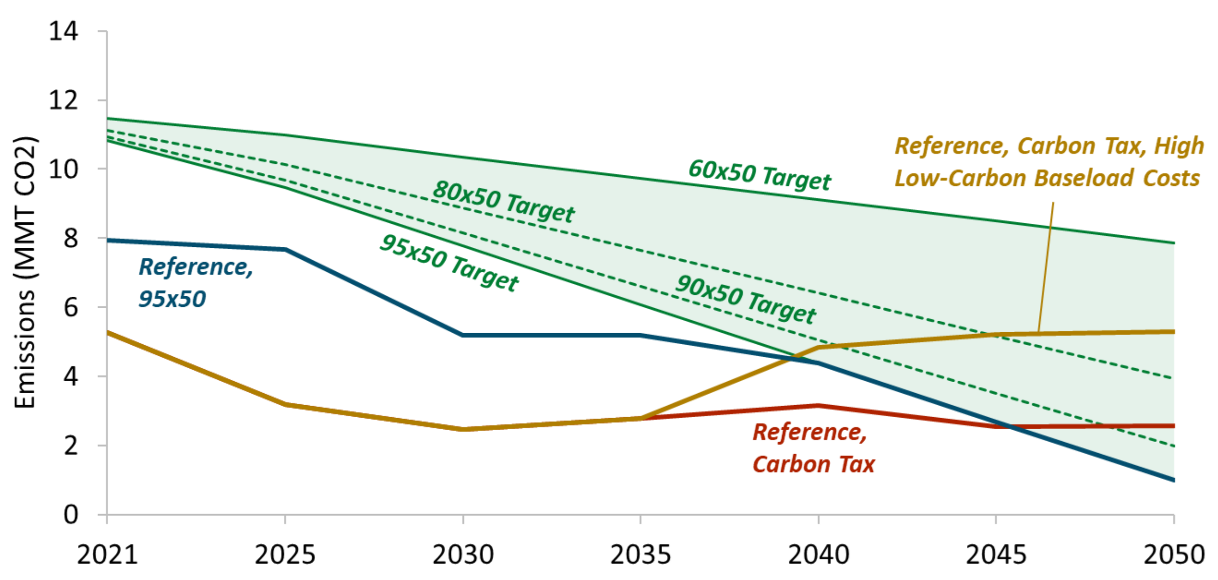


Figure 4-23. Total Installed Capacity in the Carbon Tax Scenario (Reference and Large Hydro Cases)

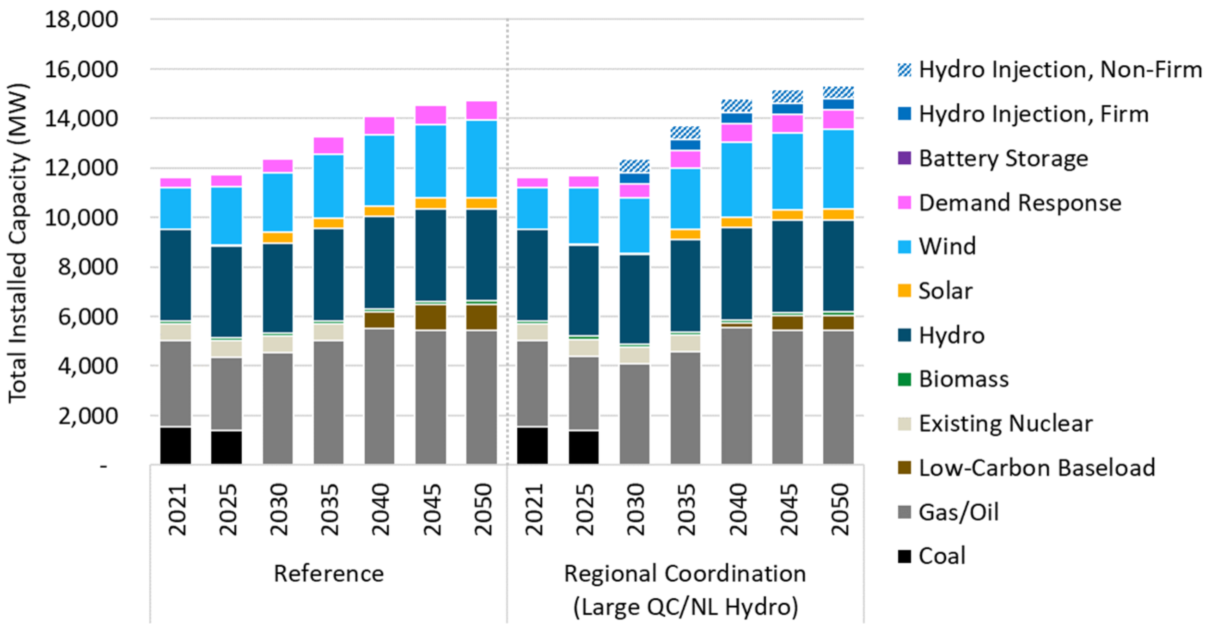
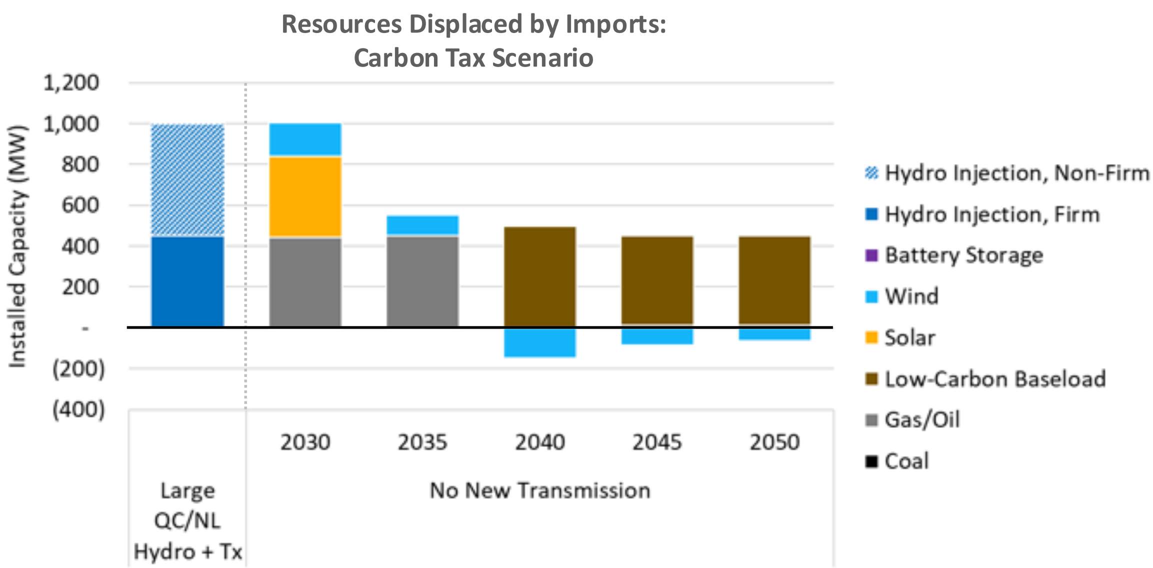


Figure 4-24. Capacity Displaced by New Hydro and Transmission in the Carbon Tax Scenario (Reference and Large Hydro Cases)



When low-carbon baseload resources are made 50% more expensive, low-carbon baseload was not built at all. Instead, the model chose to rely on more gas builds for the region's capacity and energy needs. This can be seen by comparing Figure 4-25 with Figure 4-8 (Core 95x50 case). In this case, the new hydro displaces mostly gas builds in later years, as shown in Figure 4-26; this results in the new hydro providing emissions reduction benefits in addition to economic value from avoided fuel expenditures.

Figure 4-25. Total Installed Capacity in the Carbon Tax Scenario with High Low-Carbon Baseload Cost (Reference and Large Hydro Cases)

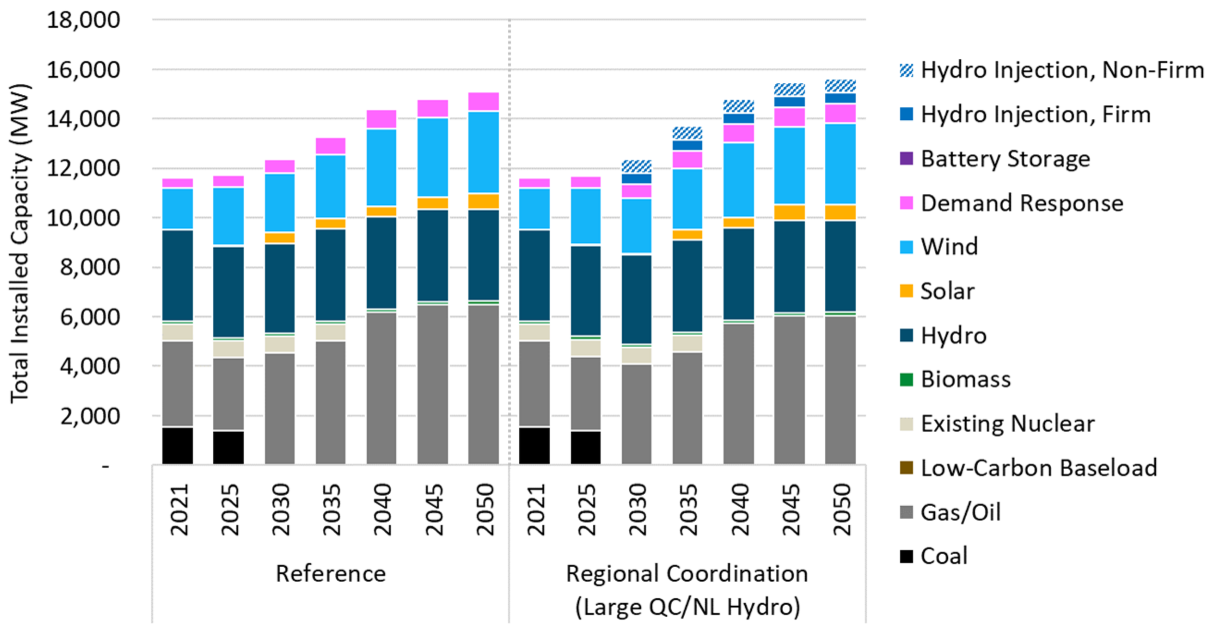
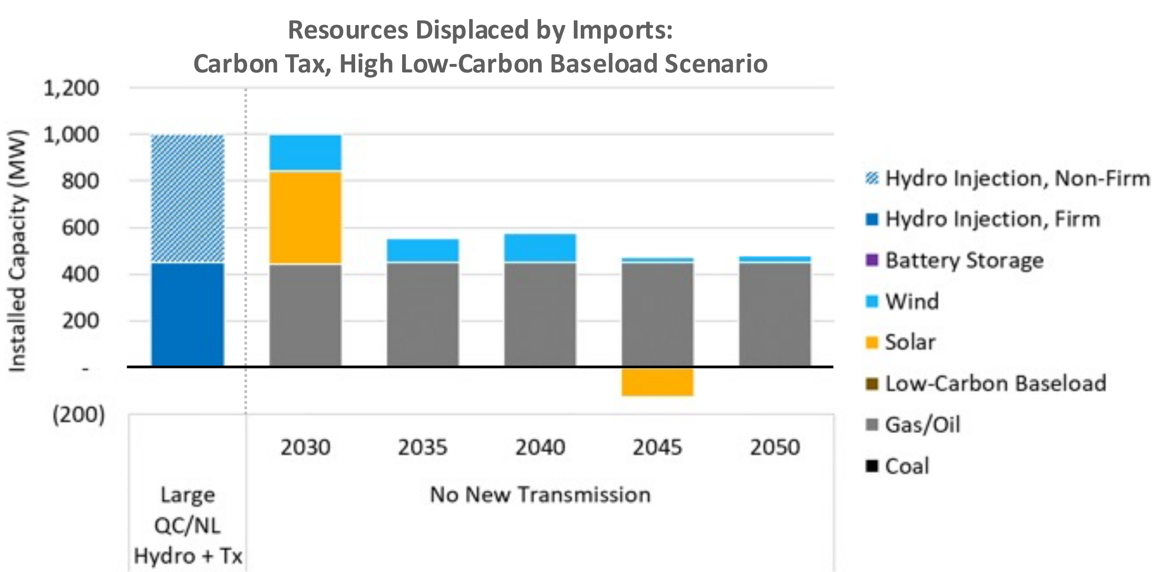


Figure 4-26. Capacity Displaced by New Hydro and Transmission in the Carbon Tax Scenario with High Low-Carbon Baseload Cost (Reference and Large Hydro Cases)



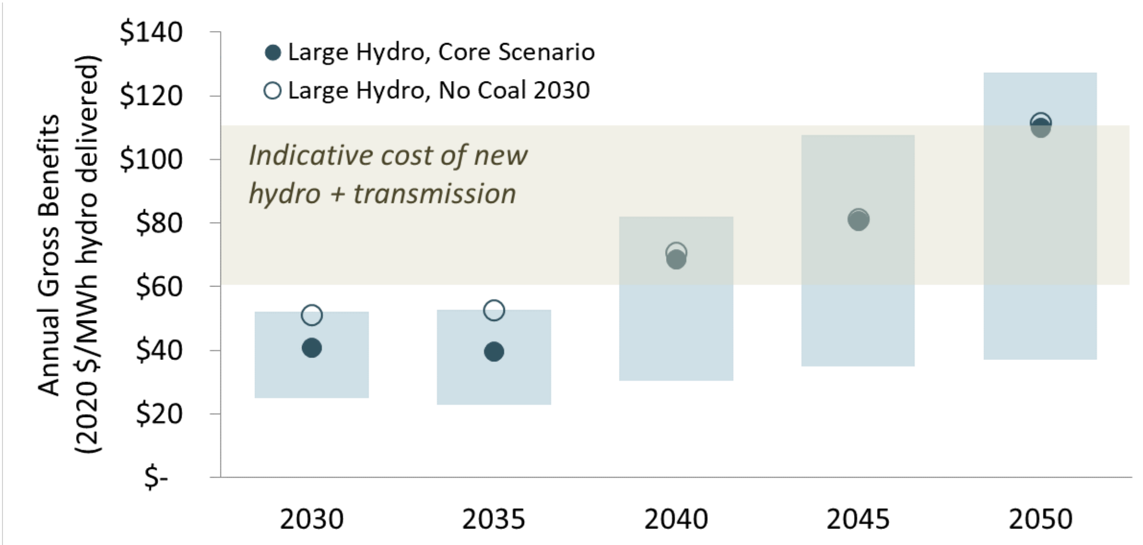
4.3 Gross Benefits of Transmission and Renewable Energy Injection

In addition to the scenarios shown in Section 4.2, additional scenarios were modeled by varying the seasonal/daily availability of the new hydro import, amount of firm capacity it can provide, and resource potential and costs of other resources in the region. These variations are meant to capture some technology and cost uncertainties and provide a range of likely benefits of the transmission line and associated clean energy imports. Figure 4-27 and Figure 4-28 show the range of gross benefits of the new hydro and transmission across the scenarios considered in this study under the 95x50 GHG target for the large QC/NL hydro line and for ML2, respectively. Gross benefits are calculated as the difference between the Reference case and Injection case within each scenario, without considering the cost of new hydro and transmission. Indicative costs of delivered hydro energy and new transmission lines are shown in Figure 4-27 and Figure 4-28 for comparison. These cost ranges are based on estimates by the utilities working group. They are meant to provide high level estimates of costs only; actual project costs would require more detailed analysis and the price of contracted energy and capacity would be dependent on the commercial arrangement between counterparties. Gross benefits (indicated by the light blue columns) within or above the range of costs (indicated by the light tan band) indicate a range of net benefits.

In both scenarios, potential gross benefits of the new hydro and transmission increase as emissions target becomes more stringent in later years. Given the time horizon of this study, the new hydro and transmission serve as a hedge against considerable uncertainties, such as the resource potential of renewable resources and commercialization of new carbon baseload technologies. Furthermore, comparing Figure 4-27 and Figure 4-28 shows the gross benefit of the large clean energy injection and the Maritime Link 2 injection are relatively similar on a generation share ($/MWh) basis.

As we show in Table 3-3, there are additional benefits of the new hydro and transmission which are not explicitly modeled in our current framework. These benefits could include increased reliability in the region (for example with the new transmission lines providing emergency capacity from the new hydro or facilitating regional coordination), lower energy security risks, lower carbon emissions.

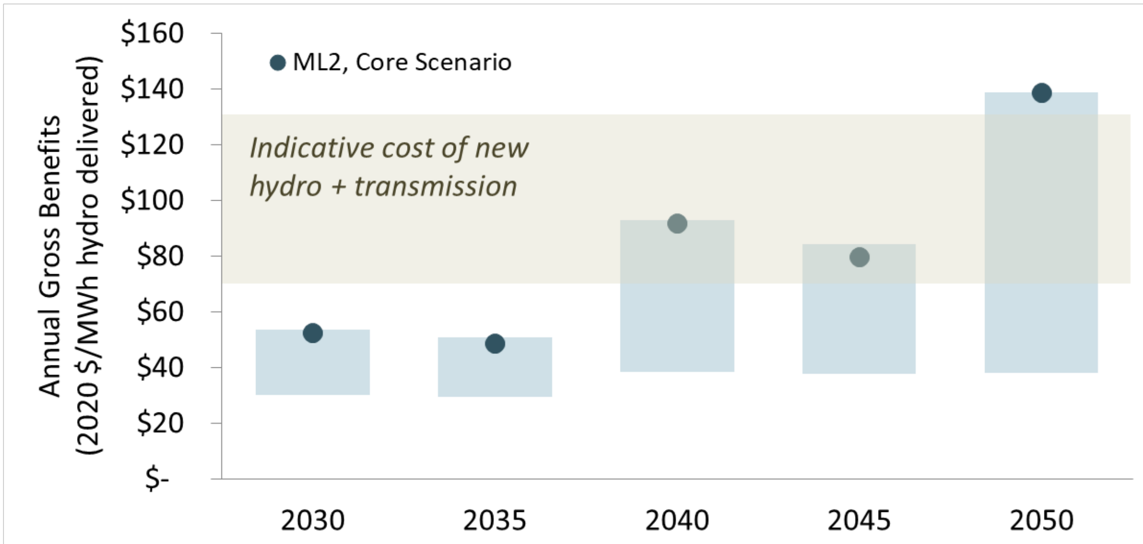
Figure 4-27. Annual Gross Benefits of New Hydro and Transmission, Large Hydro Scenarios under 95x50 GHG Target[14]



Gross benefits gives total value of line (does not include any estimate of cost of line, cost of capacity, cost of energy for resources transmitted over the line).
Upstream transmission costs in Quebec not included in indicative cost of new hydro + transmission.

[14] Indicative costs include $1.6B in capital cost for transmission backbone upgrades between Nova Scotia and New Brunswick under a range of financing assumptions (low: 2% financed over 50 years; high: 7% financed over 30 years), and a range of delivered energy costs of $50 to $80 per MWh; any required transmission upgrades to the Quebec transmission system would either be incremental or would need to be included in the delivered energy cost. The actual cost of the transmission lines and the price of the energy and capacity delivered over the line would be subject to commercial arrangement between the counterparties.

Figure 4-28. Annual Gross Benefits of New Hydro and Transmission, ML2 Scenarios under 95x50 GHG Target[15]



Gross benefits gives total value of line (does not include any estimate of cost of line, cost of capacity, cost of energy for resources transmitted over the line).

[15] Indicative costs include $1B in capital cost for 250MW undersea transmission cable between Nova Scotia and Newfoundland and Labrador under a range of financing assumptions (low: 2% financed over 50 years; high: 7% financed over 30 years), and a range of delivered energy costs of $50 to $80 per MWh. The actual cost of the transmission lines and the price of the energy and capacity delivered over the line would be subject to commercial arrangement between the counterparties.

5 Conclusions

As the Atlantic Canada provinces pursue a range of challenging economy-wide greenhouse gas reduction targets, the electricity system will play a key role in helping facilitate near-complete decarbonization of electric supply and support the electrification of transportation, buildings, and industry. Keeping electric supply reliable and affordable will be critical, especially in an electrified future in which electricity is the main source of heating and mobility. While variable renewable energy sources such as wind and solar can provide significant energy benefits and help to decarbonize the power supply, complementary resources will be needed to provide essential grid services, maintain system reliability, and provide power during periods of low wind and low solar generation. Nevertheless, with increased regional coordination the region can take advantage of significant hydropower sources in Quebec and Newfoundland and Labrador to help replace retiring coal units within the region with clean electricity.

The following key findings provide new insight into how the Atlantic Canada electricity systems can reliably accommodate this dual challenge of growing electricity demand—increasingly characterized by peak winter heating demand—and reducing emissions to nearly zero.

+ **Regional Decarbonization in Atlantic Canada will require transformational change in all sectors of the economy**. Key strategies for mitigating economy-wide greenhouse gas emissions are: continued deployment of energy efficiency; widespread electrification of end uses in buildings and transportation; deep decarbonization of electricity supplies.
+ **Electricity demand is likely to increase significantly over the next three decades.** As electrification of transportation and building end-uses continues, the region is likely to see growth in both annual electricity sales as well as peak electricity demand. These increases occur despite significant energy efficiency and demand response measures which are included in the scenarios. Absent these measures, demand growth would be even higher.
+ **Renewable electricity generation will play a major role in providing zero-carbon energy to the region.** Renewable generation is needed to displace fossil fuel generation in the regional electricity system and to provide zero-carbon energy for vehicles and buildings. Regardless of regional coordination measures to import dispatchable, clean energy from Newfoundland and Labrador or Quebec, the Maritimes will require significant construction of in-region renewable energy to provide zero-carbon energy and decarbonize the electric power supply.
+ **Achieving very deep carbon reductions in the electric supply sector will become increasingly difficult in the Maritimes as existing thermal generation is retired**. Due to technical limitations on the existing system's ability to integrate wind and solar, the need for supply during long periods of variable renewable resource unavailability, and the relatively limited geographic diversity of variable renewable resource options within the region the scope for continuing to integrate variable renewable resource options within the Maritimes is limited. Achieving very deep levels of decarbonization will thus require firm, dispatchable low-carbon energy and capacity to ensure reliability. Without broader regional coordination, this would mean leaning on resources which have not yet proven commercial viability, such as advanced nuclear or carbon capture and sequestration.
+ **Imported low carbon energy has significant value which grows over time as carbon targets become more stringent and as reliability requirements become more difficult to meet.** Imported hydropower or other dispatchable, clean energy can meet the need for zero-carbon electricity and the need for firm capacity for system reliability, acts as a hedge against significant uncertainty in commercial development of low-carbon

baseload, and shows significant value under a wide variety of uncertainties, in particular in scenarios examining 2030 coal retirement.

6 Appendices

6.1 Detailed PATHWAYS Assumptions

As discussed in the main body of the report, this study relied on E3's PATHWAYS model for the Atlantic Canada region. Below we provide study assumptions used as part of this analysis.

6.1.1 Base year energy demand benchmarking

The Atlantic Canada PATHWAYS model includes a representation of energy demand in residential and commercial buildings, transportation, and industrial sectors. To further disaggregate energy demand into subsectors, we use a variety of data, sourced primarily from data sets and surveys such as the US EIA National Energy Modeling System (NEMS); the Residential Energy Consumption Survey (RECS); the Commercial Buildings Energy Consumption Survey (CBECS); US Department of Transportation (DOT) data on vehicle mileage; and Atlantic Canada regional data such as from Environment Canada; the Canada Energy Regulator; and utility specific electricity use from integrated resource plans or integrated system plans.

In calculating energy demands, E3 benchmarked energy consumption within each province to data from the Canada Energy Regulator, which reports fuel consumption by sector and fuel. E3 performed a bottom-up based accounting of the appliances and vehicles in the region and relied on a variety of data on appliance and vehicle efficiencies, as well as usage patterns, to benchmark residential, commercial, and transportation energy demands within the region.

E3 used two modeling approaches to analyze energy demand in each sector: (1) stock rollover, in which an explicit accounting of rollover appliances and equipment were calculated and used to account for energy and GHG emissions; or (2) total energy by fuel, in which the total energy consumption was directly modeled. The stock rollover approach was used when infrastructure data were available from public data sources; when only limited or poor-quality data on stock existed, E3 used a total energy approach.

6.1.2 Forecasting energy demand in future years

Demands for energy services in PATHWAYS are driven by forecasts of population, building square footage, vehicle miles traveled, and other drivers of energy services. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs. PATHWAYS calculates energy demand, GHG emissions, and the portfolio of technology stocks in selected sectors, on an annual basis through 2050. When forecasting energy use, E3 used a variety of sources including EIA and NREL forecasts of appliance efficiencies and vehicle efficiencies, in conjunction with underlying macroeconomic drivers derived from the Annual Energy Outlook (AEO).

6.1.3 Electric load forecast

Since the PATHWAYS model is based on a bottom-up forecast of technology stock changes across the economy, the model does not use a single load forecast or energy efficiency savings forecast as a model input. The electric load forecast is an outcome of the stock change and efficiency improvements embedded in each scenario; these modeling assumptions may not reflect specific future energy efficiency programs or activities but are meant to produce loads consistent with a range of approaches to achieving carbon neutrality across the economy.

6.1.4 Electric load shaping

To maintain electric system reliability, it is important to match the temporal supply and demand of electricity. The mitigation scenarios characterized in this study include adoption of electric vehicles and building electrification, which can significantly change the historical relationship between temperature conditions and electric load. To capture this dynamic, this study scaled historical system load shapes to future years to form the basis of the hourly load forecast and adjusted this projected hourly load forecast by accounting for simulated end-use load shapes for light duty transportation and electric heat pumps.

6.1.5 Load shape development

E3 developed normalized hourly load shapes for two particularly important sources of electrification, residential space heating and light duty vehicle transportation. The E3 RESHAPE model was used to develop residential space heating load shapes that reflect weather, technology characteristics and household behavior. Similarly, E3 utilized its model, EVGRID-EVLST for light duty vehicle transportation patterns. Remaining electric load was assumed to follow the existing system-wide load shape.

6.2 Detailed RESOLVE Assumptions

A complete set of input data are provided in the study's corresponding RESOLVE inputs workbook.[16] For more detailed data on the RESOLVE model, please see the accompanying inputs workbook.

[16] Full technical workbook is available upon request (available in English only). Please send a request for the workbook to nrcan.acppc-capep.rncan@canada.ca