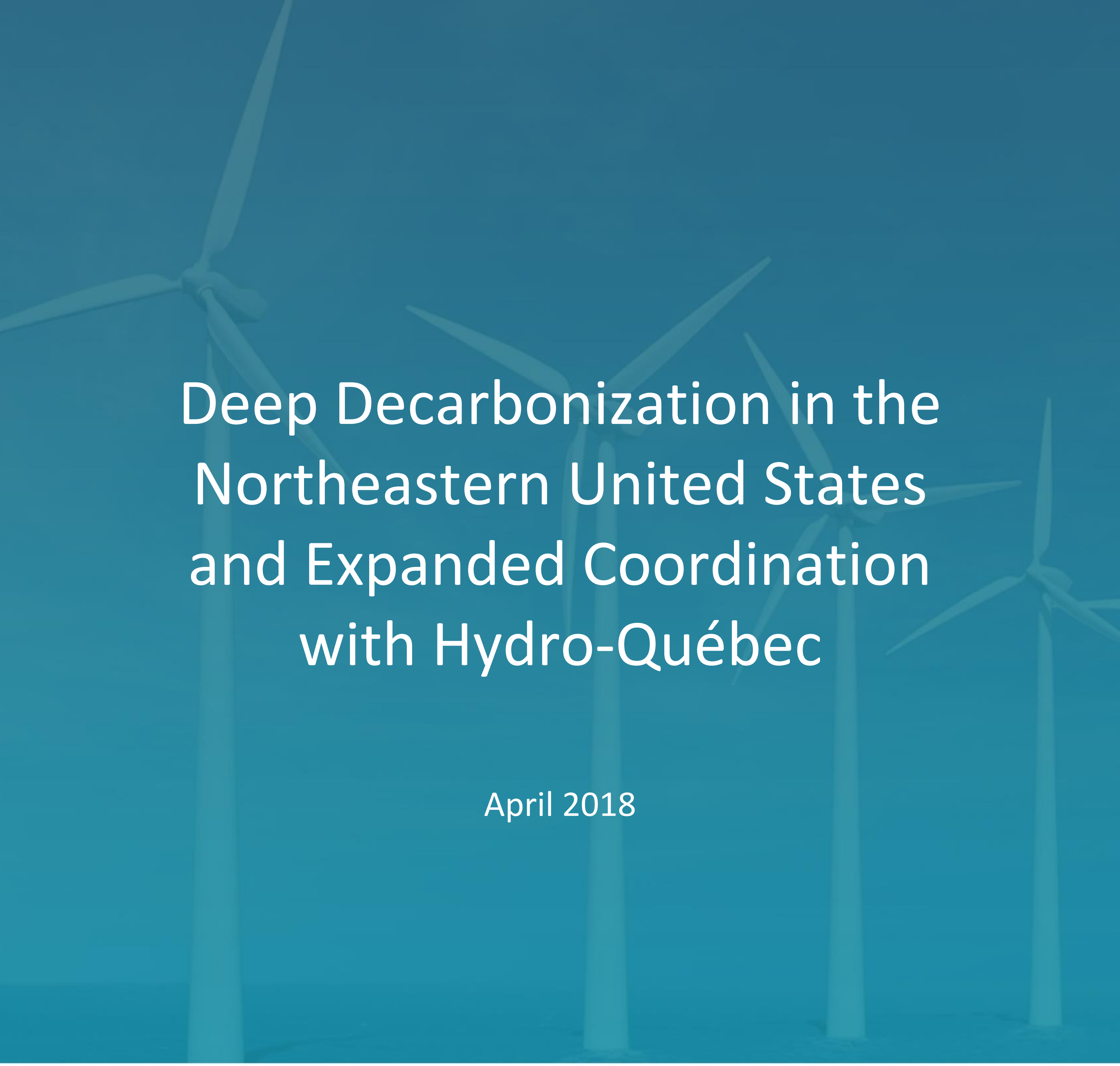

Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec

April 2018

EVOLVED ENERGY RESEARCH

SUSTAINABLE DEVELOPMENT SOLUTIONS NETWORK
A GLOBAL INITIATIVE FOR THE UNITED NATIONS

Hydro Québec

Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec

Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec is published by the Sustainable Development Solutions Network (SDSN) in collaboration with Evolved Energy Research (EER) and Hydro-Québec (HQ).

Publication date: April 2018

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Cite this report as:

Williams, J.H., Jones, R., Kwok, G., and B. Haley, (2018). *Deep Decarbonization in the Northeastern United States and Expanded Coordination with Hydro-Québec*. A report of the Sustainable Development Solutions Network in cooperation with Evolved Energy Research and Hydro-Québec. April 8, 2018.

A PDF version of this report may be downloaded from:

U.S. Deep Decarbonization Pathways Project
http://usddpp.org/

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DEEP DECARBONIZATION IN THE NORTHEASTERN UNITED STATES AND EXPANDED COORDINATION WITH HYDRO-QUÉBEC

Sustainable Development Solutions Network
Evolved Energy Research
Hydro-Québec

April 2018

ACKNOWLEDGMENT

The authors would like to gratefully acknowledge the contributions of the distinguished advisory committee who agreed to review the initial design and final results of this study, and provided many helpful comments and suggestions. The report does not represent the positions of the advisory committee members or their organizations. The members of the advisory committee included:

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Table of Contents

Table of Figures

Table of Tables

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Executive Summary

The states of the northeastern United States – New York, Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine – have declared their intention to dramatically reduce their greenhouse gas emissions by mid-century, to levels consistent with the Paris Agreement's call to limit human-caused global warming to 2˚C or less. The emission reductions objectives adopted generally fall in the "80 x 50" range, or 80% below 1990 levels by the year 2050 (Table 1).

Table 1. Mid-century greenhouse gas emission reduction goals in the northeastern U.S.

State	2050 Goal
New York	80% below 1990 levels
Connecticut	80% below 2001 levels
Rhode Island	80% below 1990 levels
Massachusetts	80% below 1990 levels
Vermont	80-95% below 1990 levels
New Hampshire	80% below 1990 levels
Maine	75-80% below 2003 levels

This study analyzes what achieving an 80 x 50 goal throughout the region *(hereafter referred to as the "Northeast")* implies for the way that energy is supplied and used. It builds upon the 2015 study *Pathways to Deep Decarbonization in the United States* by the Deep Decarbonization Pathways Project. The research was sponsored by the Sustainable Development Solutions Network (SDSN) in collaboration with Hydro-Québec (HQ), and conducted by Evolved Energy Research (Evolved) using the EnergyPATHWAYS energy system model, with contributions from SDSN and HQ's research institute, IREQ.

The analysis has three main objectives:

1. To understand what changes in energy system infrastructure and technology are required to achieve the 80 x 50 goal in the Northeast
2. To understand the potential effect of expanded Northeast-HQ coordination on the cost of achieving the 80 x 50 goal in the Northeast
3. To determine if potential benefits warrant examination in greater depth, and if so what are the right questions, tools, and stakeholders for a Phase 2 study

What changes in energy system infrastructure and technology are required to achieve the 80 x 50 goal in the Northeast?

This question is addressed through the comparison of two scenarios developed for the Northeast. The first is a reference case, based on the Department of Energy's *Annual Energy Outlook 2017*, a business-as-usual forecast out to mid-century with a highly detailed representation of energy service demand, supply infrastructure, and end-use technology, adapted to incorporate currently implemented policies in the Northeast. This scenario results in emissions that far exceed the 80 x 50 goals. The second scenario is a deep decarbonization pathway (DDP) – a technical blueprint of sector by sector and year by year changes in the energy system – that achieves the 80 x 50 goal.

The results show that the deeply decarbonized energy system can provide the same energy services to the economy and daily life – mobility, lighting, heating, cooling, etc. – as the business-as-usual case. It can be achieved through the ongoing deployment of efficient, low-carbon technologies that are already commercial, combined with the steady retirement of low-efficiency, high-carbon technologies. While this transition does not have to be accomplished overnight, it also cannot be delayed if the mid-century target is to be met. The changes required are not incremental improvements over the *status quo*. They are unprecedented and transformational.

The extent of the transformation is shown by three metrics that represent the three principal measures needed to reach that 80 x 50 target (Table 2). First, greatly increased efficiency of energy end use, as indicated by a 40% decrease in energy use per capita between today and mid-century while maintaining all existing energy services. Second, reaching a very low carbon intensity of electricity, 29 grams of CO_2 per kilowatt-hour, an 87% decrease from current levels. Third, switching of end uses in buildings, industry, and transportation from direct combustion of fossil fuels to electricity, represented by a tripling of the electricity share, to 55% of final energy consumption from 18% today.

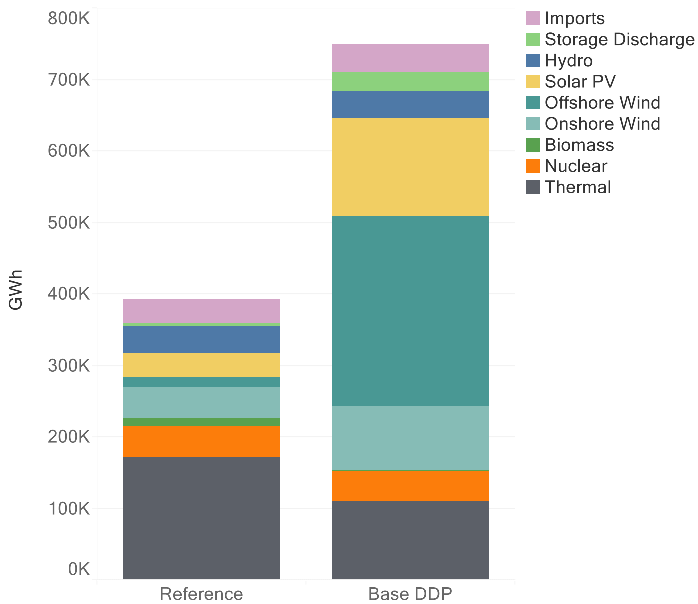
Table 2. Metrics for "three pillars" of deep decarbonization, comparing current values to DDP base case

Pillar	Unit	2015 value	2050 DDP	% change
Energy efficiency	Annual per capita energy use (MMBtu/person)	168	101	-40%
Carbon intensity of electricity	Carbon emissions per unit of electricity (kg CO_2/MWh)	228	29	-87%
Electrification of end uses	Electricity share of end use energy consumption (%)	18%	55%	+210%

These changes are sometimes called the *three pillars* of deep decarbonization, because the outcome rests on having all three at the same time. When they occur together, there is a multiplicative effect on emissions reductions. For example, in the case of electric vehicles, electric drive trains are both more energy efficient than those with internal combustion engines and displace fossil fuels with near-zero carbon electricity. The same logic holds for the replacement of natural gas and oil furnaces and water heaters with efficient electric heat pumps. The most formidable policy challenge on the demand side of the energy system will be attaining the rapid electrification of end uses.

For the electricity sector, there are two simultaneous requirements. First, there must be a major increase in electric load, roughly doubling current levels by mid-century. In the DDP base case for the Northeast, load in 2050 is 86% higher than the reference case, due primarily to electrification of virtually all light-duty vehicles, plus meeting two-thirds of building space and water heating demand. Second, there must be a vast increase in low carbon generation. Given current policy preferences in the Northeast, the DDP base case achieves this with renewable energy rather than new nuclear or fossil generation with carbon capture and storage. In 2050, two-thirds of all generation comes from solar PV and wind power, while thermal power plants burn a mixture of natural gas and biomass-based renewable natural gas to stay within carbon constraints (Figure 1).

Figure 1. Northeast generation mix in 2050 reference case and DDP case



These requirements pose three serious challenges for electricity provision in a Northeast 80 x 50 scenario. First, electricity systems with very high shares of wind and solar generation can have imbalances between energy supply and demand that are of larger magnitude than can be addressed with natural gas generation constrained by carbon emission limits. These imbalances are also on longer time scales (weekly to seasonal) than can be addressed by hourly-to-diurnal storage technologies such as batteries. Second, an unprecedented buildout of renewable resources is required to decarbonize electricity generation. This includes a high proportion of offshore wind in increasingly remote locations to supplement onshore wind and solar PV, as the best sites for these are utilized or high daytime curtailment makes it difficult to reach higher penetrations. Third, the cost of generation increases steeply for remote offshore wind, as transmission costs exceed generation costs, and the cost of balancing resources also increase steeply when scarce biomass is used as a low-carbon fuel in thermal generation.

What are the potential effects of expanded Northeast-HQ coordination on the cost of achieving the 80 x 50 goal in the Northeast?

This question is posed as a response to the electricity sector challenges described above. HQ already plays an important role in Northeast electricity, exporting 22 terawatt-hours per year of carbon-free electricity over more than 4000 megawatts of interconnection. This transmission capacity benefits both the Northeast and Québec as it allows south to north exports at certain times during the year in combination with the predominantly north to south flow, keeping transmission utilization rates high. Several factors make expanded coordination an option worth investigating. First, within Québec there is significant new resource potential for onshore wind and hydro at relatively low cost within close geographic proximity to the Northeast. Second, the HQ system, with its large reservoir capacity, has the latent flexibility to provide balancing on both a daily and seasonal scale.

To analyze potential costs and benefits, the DDP base case was compared to four different scenarios of expanded Northeast-HQ coordination that also reach the 80 x 50 target. These scenarios vary along different axes of what "increased coordination" could mean: (i) expanded exports and transmission capacity between Canada and the Northeast, versus no expansion; (ii) new hydro resources versus new wind resources, in both cases developed within Québec for export; and (iii) including the PJM balancing area as a U.S. participant in expanded coordination, versus including the Northeast only.

These scenarios were compared to the DDP base case in terms of net costs and benefits, investment requirements, transmission requirements, generation mix, and operational changes (Table 3). The cases with expanded hydro and expanded wind resources in Québec both show a net benefit of more than $4.2 billion (current US$) per year. The case with expanded hydro plus PJM involvement shows a net benefit of almost $5 billion per year, but $1.9 billion of that is realized within PJM as production cost savings rather than the Northeast as a consequence of avoided renewable curtailment. The case with expanded transmission capacity has a relatively small net benefit of $130 million per year.

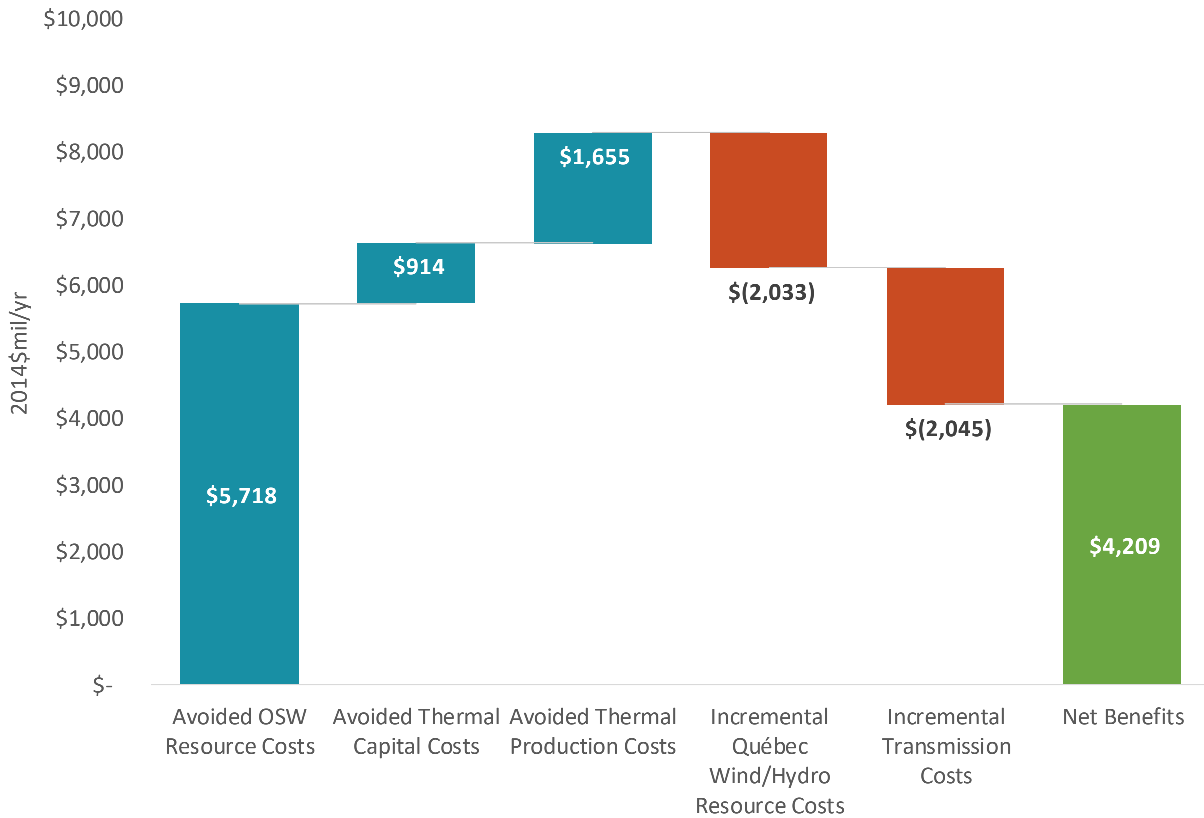
Table 3. Net benefits in 2050 of four increased coordination scenarios relative to deep decarbonization base case.

Scenario	New HQ/Northeast Ties	New NYISO/PJM Ties	New HQ Hydro for Export	New HQ Wind for Export	Net Benefits ($mil/yr.)
Expanded Wind	+9,090 MW	n/a	n/a	+30 TWh	**$4,209**
Expanded Hydro	+9,090 MW	n/a	+30 TWh	n/a	**$4,380**
Transmission Only	+9,090 MW	n/a	n/a	n/a	**$132**
PJM Coordination	+9,090 MW	+3,000 MW	+30 TWh	n/a	**$3,099** ***$4,993**

*Including production cost savings realized in PJM.

The costs and benefits of coordination are illustrated by the expanded wind case (Figure 2). The benefits come from replacement of the costliest offshore wind resources that would otherwise be required with less costly Canadian onshore wind, and from utilization of the HQ system for balancing, allowing south-north flows of excess solar generation that would otherwise be curtailed in the Northeast, and avoiding the high cost thermal biomass balancing resource. The gross benefits of $8.3 billion per year from these savings are partially offset by increased resource costs (in Québec) and transmission costs (between Québec and the Northeast) of $4.1 billion per year, resulting in a net benefit of $4.2 billion per year.

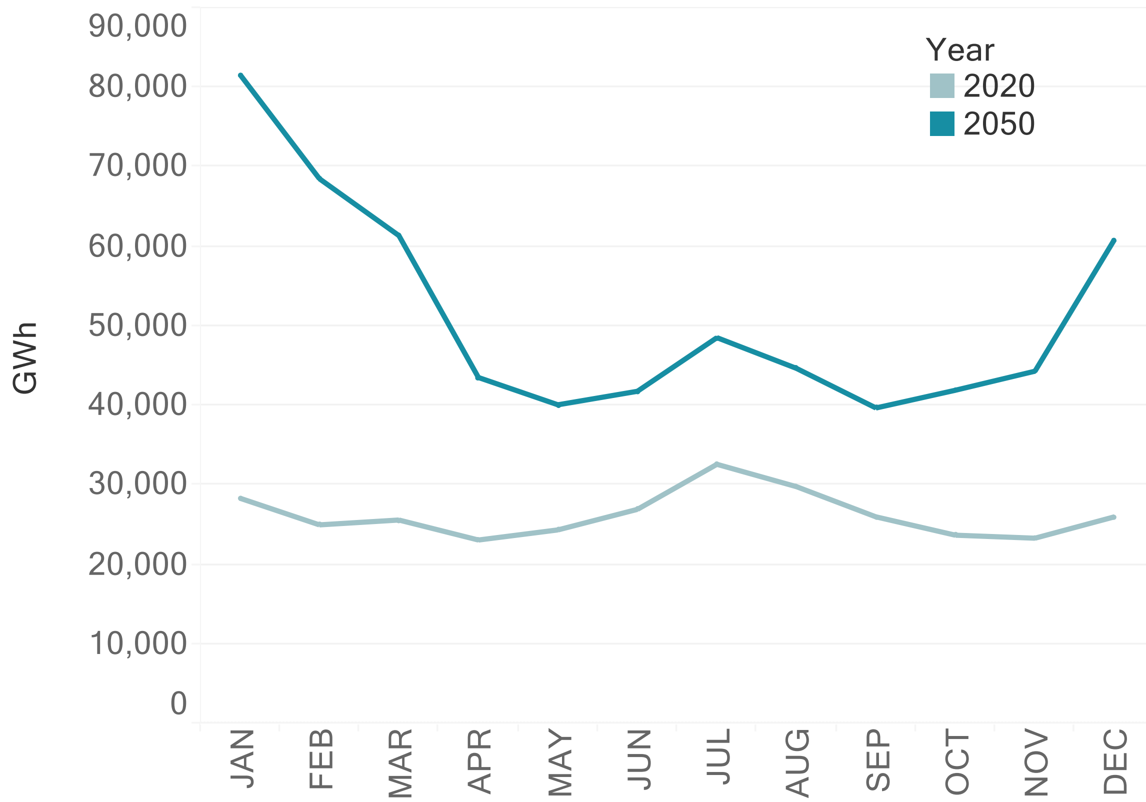
Figure 2. Annual costs and benefits in 2050 of expanded wind case relative to base DDP case.



Net benefits of more than $4.2 billion per year represent a reduction of more than 6.5% of the annual incremental cost of electricity generation in the Northeast in the DDP base case. A sensitivity analysis with offshore wind at 50% of its projected cost in the base case, and HQ wind at 50% higher cost, reduces net benefits to $300 million per year, while the opposite sensitivity (50% lower HQ wind cost, 50% higher offshore wind cost) increases them to $8.4 billion per year. For offshore wind and HQ incremental hydro, the sensitivity results are similar.

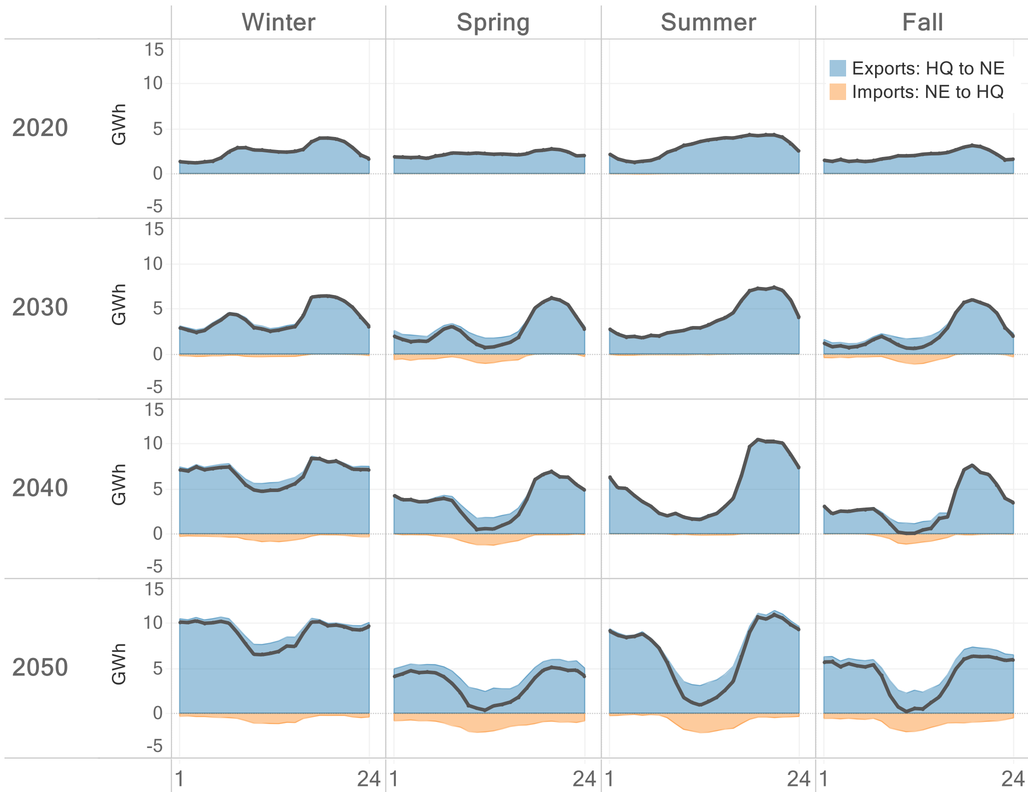
The scenario results indicate several potential operational challenges for the HQ system. The economic benefits of expanded coordination derive primarily from operating HQ's system as a regional battery with extensive south-north as well as north-south flows. This takes greater advantage of the flexibility of the HQ reservoir system, but is a departure from the longstanding model of fixed schedule electricity exports. These challenges derive partly from changes in the seasonal timing of peak load in the Northeast under deep decarbonization due to the electrification of heating loads, so that peak loads occur in January, coincident rather than complementary with the HQ system peak, also in the winter. (Figure 3).

Figure 3. Base DDP Case Monthly Electricity Consumption for the Northeast



In addition to a new seasonal operating regime, the daily operating regime also changes dramatically. Figure 4 shows transmission flows between HQ and the Northeast, illustrating the evolving nature of imports and exports over time as the Northeast's generation mix becomes increasingly inflexible due to higher wind and solar penetrations, and the transfer capability between the two regions increases. From 2020 to 2050, overall exports from HQ to the Northeast increase, but the daily pattern becomes more dynamic, with exports ramping down during sunrise and ramping up during sunset. This pattern reflects the high levels of solar PV generation in the Northeast, with HQ importing electricity from the Northeast during daylight hours, particularly during the spring and summer, decreasing HQ hydro generation and increasing reservoir storage.

Figure 4 Expanded Wind Case: HQ-Northeast Net Interchange



Note: positive values reflect net exports from HQ to Northeast, while negative values reflect energy flows south-to-north.

A consequence of increased diurnal swings in imports and exports is potentially much faster ramping (the rate of increased or decreased generation in MW per hour) of the HQ system than at present.

Do the potential benefits warrant examination in greater depth, and if so what are the right questions, tools, and stakeholders for a Phase 2 study?

The scale of potential benefits shown by this analysis – greater than 6.5% of the incremental generation cost of deep decarbonization – indicates that a deeper investigation is warranted. The key topics and analytical needs of a prospective Phase 2 study are suggested by the findings, and the limitations, of this initial analysis. The main issues pertain to scenario design, cost, operations, and environment.

(1) The DDP base case used in this study is not the only or best DDP for the Northeast. It was designed to illustrate general features of DDPs that have proven to be robust in similar studies, such as the "three pillars," and provide boundary conditions for the expanded coordination analysis. It reflects current policy preferences in the region, but not necessarily the best possible resource mix. A Phase 2 study should develop a wider set of technology pathways and ranges of assumptions about cost and performance, with inputs from regional stakeholders and experts.

(2) The expanded coordination scenarios developed for this study are not optimized for cost. The resource builds, export levels, and transmission additions were selected to illustrate a range of options for expansion of Northeast-HQ coordination, but were not meant to represent the best possible economic outcome. Potential benefits could be larger than these scenarios show. In addition, stability and contingency assessments are needed to understand the implications of tripling interties between the Northeast and HQ. A follow-on study should feature optimal capacity expansion, and greater transmission representation in production cost and power-flow modeling, accompanied by extensive sensitivity and uncertainty analysis.

(3) The implications of the operational challenges for the hydro system described above – major changes in the seasonal and diurnal timing and ramp rates for the filling and emptying of reservoirs - will require extensive hydrological and hydro system operations modeling. Potential impacts of climate change on hydrologic flows should also be factored in.

(4) The siting and development of new hydro or wind resources and transmission upgrades will require environmental assessment on both sides of the border. Prior to assessment of actual proposed projects, an initial scoping of potential environmental limitations can help provide constraints and cost estimates needed for Phase 2 modeling and scenario design.

A Phase 2 study would aim to inform the discussions among key regional stakeholders that would be required before any concrete steps toward expanded coordination are made. A central issue is how system-wide benefits, costs, and risk would be allocated among the parties, and what changes in current wholesale market and RTO rules and procedures would be necessary to allow greater cross-border integration of planning, procurement, and operations.

It should be acknowledged that the vision of expanded coordination in the present study is narrower than what could be imagined in an urgent mobilization to rapidly reduce greenhouse gas emissions. A larger vision could include fully integrated regional planning and resource markets, and possibly synchronization and full AC interconnection. However, given the limits of historical levels of coordination – including among the states and regional transmission organizations (RTOs) of the Northeast, as well as across the international border – the objective of a limited expansion makes sense as an initial Phase 2 focus. A key to success will be the participation of regional stakeholders and experts from government, utilities, RTOs, labor, and environmental organizations, both in technical discussions and in creating a shared vision of how to achieve a low carbon future.

Introduction

The Paris Agreement, signed by 195 countries, calls on the international community to limit human-caused global warming to “well below 2˚C” (<2˚C). Voluntary commitments by individual countries, called “nationally defined contributions” (NDCs), describe the actions each will take to meet the <2˚C goal. Since the initial NDCs typically reach only to 2025 or 2030, the Paris Agreement also calls for countries to produce “low-emissions development strategies” that lay out a <2˚C-compatible trajectory to mid-century. Many countries, including the United States and Canada, define this to mean the measures required to achieve at least an 80% reduction in greenhouse gas (GHG) emissions below 1990 levels by the year 2050 (“80 x 50”).

The Deep Decarbonization Pathways Project (DDPP), an international consortium of researchers from high-emitting countries, has pioneered the development of pathways, or detailed blueprints of technical alternatives, for reaching long-term low carbon goals. This work has raised global awareness of the transformational changes required to achieve a <2˚C outcome. Two studies by the U.S. DDPP research team, Pathways to Deep Decarbonization in the United States [1] and Policy Implications of Deep Decarbonization in the United States [2], strongly influenced the Obama Administration’s United States Mid-Century Strategy for Deep Decarbonization [3], as well as non-governmental efforts such as the Risky Business Project’s From Risk to Return: Investing in a Clean Energy Economy [4] and NRDC’s America’s Clean Energy Frontier: The Pathway to a Safer Climate Future [5]. The report of the Canadian DDPP team, Pathways to Deep Decarbonization in Canada [6], played a similar role in the development of Canada’s Mid-Century Long-Term Low-Greenhouse Gas Development Strategy [7].

The Paris agreement recognizes the essential role of subnational actors – state and local governments, businesses, and investors – in reaching the <2˚C goal. Within some domains, these actors have greater jurisdictional authority, technical know-how, and financial resources than national governments, and many have pioneered climate change and clean energy policy. In this regard, the states of the northeastern United States (“Northeast”) – New York plus the New England states of Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine – have played a leading role within the United States, through initiatives ranging from New York’s Clean Energy Standard to New England’s Regional Greenhouse Gas Initiative. The Northeast has embraced the long-term deep decarbonization objective, with all the individual states adopting 80 x 50 or similar targets (Table 1).

The present study examines what achieving an 80 x 50 target in the Northeast will entail in concrete technical and economic terms. It was initiated by the Sustainable Development Solutions Network (SDSN), co-convener of the DDPP, and sponsored by SDSN and Hydro-Québec (HQ). The research was conducted by Evolved Energy Research (Evolved), the technical leaders of the U.S. DDPP team, with contributions from SDSN and Hydro-Québec’s research institute, IREQ.

The study has two main objectives. The first is to understand exactly what an economy-wide 80% reduction in GHG emissions by 2050 implies for both energy supply and energy consumption in the Northeast, with explicit sector-by-sector and year-by-year detail. It is addressed through a technically rigorous scenario analysis that compares a deep decarbonization pathway (DDP) to a business-as-usual reference case, in terms of energy mix, infrastructure, and technology. The reference case is based on the Department of Energy's Annual Energy Outlook 2017, the authoritative long-term projection of the U.S. government. The DDP base case for the Northeast was developed based on the U.S.-wide scenarios in Pathways to Deep Decarbonization in the United States. Both the reference case and DDP base case were modified to include current policies of the Northeast states, ranging from clean energy standards to nuclear power plant retirements (see Table 5). These scenarios assume a status quo role for Canadian hydro, meaning that they include existing transmission capacity and exports plus currently approved expansion plans.

The second objective is to understand the potential advantages and challenges of greater coordination between the Northeast and Canada, in particular the Hydro-Québec system, in achieving the deep decarbonization goal. This is addressed by comparing the DDP base case to different scenarios of expanded Northeast-Hydro-Québec coordination that also reach the 80 x 50 emissions target. These scenarios vary along several different dimensions of what "increased coordination" might include:

1. expanded exports and transmission capacity between Canada and the Northeast, versus no expansion;
2. development of incremental hydro versus incremental wind resources in Canada for export; and
3. inclusion of the PJM balancing area as U.S. participants in expanded coordination, versus inclusion of the Northeast only.

These scenarios are compared to the DDP base case in terms of net cost/benefits, investment requirements, infrastructure changes, energy mix, and operational changes.

Hydro-Québec already plays an important role in Northeast electricity, exporting 22 TWh annually over more than 4000 MW of interconnection. This transmission capacity allows south to north exports at certain times to go with the predominantly north to south flow, which has kept transmission utilization high and costs low. Several factors make increased coordination an interesting option. First, within Québec there is significant new resource potential within close geographic proximity to the Northeast. Second, electricity systems with very high levels of wind and solar can have energy imbalances on both short and long (seasonal) time scales, while the Hydro-Québec system, with its large reservoir capacity, has the latent flexibility to provide such balancing. However, expanding coordination between the Northeast and Canadian hydro is a complex issue, which requires in-depth consideration of appropriate boundary conditions, stakeholders, objectives, assumptions, and constraints, touching on such sensitive topics as operational changes, transmission expansion, wholesale market rules, environmental sustainability, cross-border and cross-state jurisdiction, and allocation of costs and benefits among parties. Accordingly, the study is divided into two phases, which approach these issues sequentially.

In the first phase, which the current study describes, the research question is: what are the changes in energy, emissions, and system-wide costs and benefits of four different increased-coordination scenarios versus the base DDP scenario? The first phase analysis has been conducted using an energy system model called EnergyPATHWAYS. EnergyPATHWAYS has a track record in developing other national and state-level DDPs, and its features – rigorous energy balance across all sectors and fuel types, extensive performance and vintage detail on both supply and demand side equipment stocks, and an hourly electricity dispatch – make it an appropriate tool for addressing the first phase research questions.

A key outcome of this research is determining whether the potential benefits of increased coordination warrant further study in a second phase which could address the more complex questions mentioned above regarding the specifics of increased coordination. Because the changes from the status quo could be large, the analyses needed may include, but are not limited to, optimal capacity expansion modeling, power flow modeling, production-cost modeling, hydrology and hydro operations modeling, and environmental impact modeling, along with forward-looking analyses of wholesale market rules, cross-border law and regulation, and energy policies. While this might sound daunting, if Northeast states' commitment to <2˚C is pursued seriously, many aspects of energy supply and end use will have to be pursued very differently. In that context, the challenges of increased coordination with the Hydro-Québec system could prove to be smaller than others that the Northeast will face.

Methodology

Electricity is at the center of economy wide decarbonization and undergoes transformation both in electricity supply and in demand due to newly electrified loads[1]. While questions of increased coordination primarily deal with the electric power sector, the overall context and goal of exploring the broader implications of decarbonization in the Northeast required an economy wide model.

To provide both the energy system breadth and needed detail in electricity, a model called EnergyPATHWAYS was used [8]. EnergyPATHWAYS is an open-source, bottom-up energy sector model with stock-level accounting of all consuming, producing, delivering, and converting energy infrastructure and was specifically built to investigate energy system transformations. The model leaves most energy system infrastructure deployment decisions to the user; thus, it is appropriate to think of EnergyPATHWAYS as a complex accounting system or simulation model that keeps track of and determines the implications of detailed user decisions.

EnergyPATHWAYS and similar bottom up models have a rich history in scenario planning exercises. A progenitor to EnergyPATHWAYS implemented on a different platform but with a similar conceptual approach was first used in California to explore energy system transformation [9, 10] and to analyze the U.S. in the Deep Decarbonization Pathways Project [1]. Since then, EnergyPATHWAYS has been used in the Risky Business Reports [4], studies for Washington State [11], Portland [12], the U.S. Midwest Region (RE-AMP), and Mexico [13], and in NREL's Electrification Futures Study [14], as well as multiple private studies in the U.S. and Europe. What all of these studies have in common is the use of user-driven scenarios to explore the cost, energy, and emissions implications of different energy system decisions.

EnergyPATHWAYS Overview

Broadly speaking, EnergyPATHWAYS can be divided into a demand side and supply side, the former calculating energy demanded (E.g. kWh electricity and MMBtu natural gas) by different services (e.g. water heating and passenger vehicle travel), the later determining how each energy demand is met (e.g. natural gas extraction, power plants, transmission wires, and gas pipelines). Operationally this distinction is important in the model because the demand and supply sides are calculated in sequence.

Beginning on the demand side, the model starts with a set of inputs termed demand drivers. These are variables such as population or the value of industrial shipments and can be thought of as the skeleton upon which the rest of the model calculations depend. Ideally, demand driver

[1] The importance of setting appropriate boundary conditions for electricity in this study can be most clearly seen when considering electrification of heating and the impact this has on hourly load shapes. Buildings in Québec are today primarily all electric due to a history of low-cost hydro and encouraged load growth making the system strongly winter peaking. Today the Northeast has summer peaking systems and complements loads in Québec well. This synergy; however, does not last when considering what must happen in the Northeast to meet carbon goals. To miss the fact that the Northeast will also become winter peaking when decarbonizing is to potentially overstate the value of coordination due to incorrect assumptions about load complementarity.

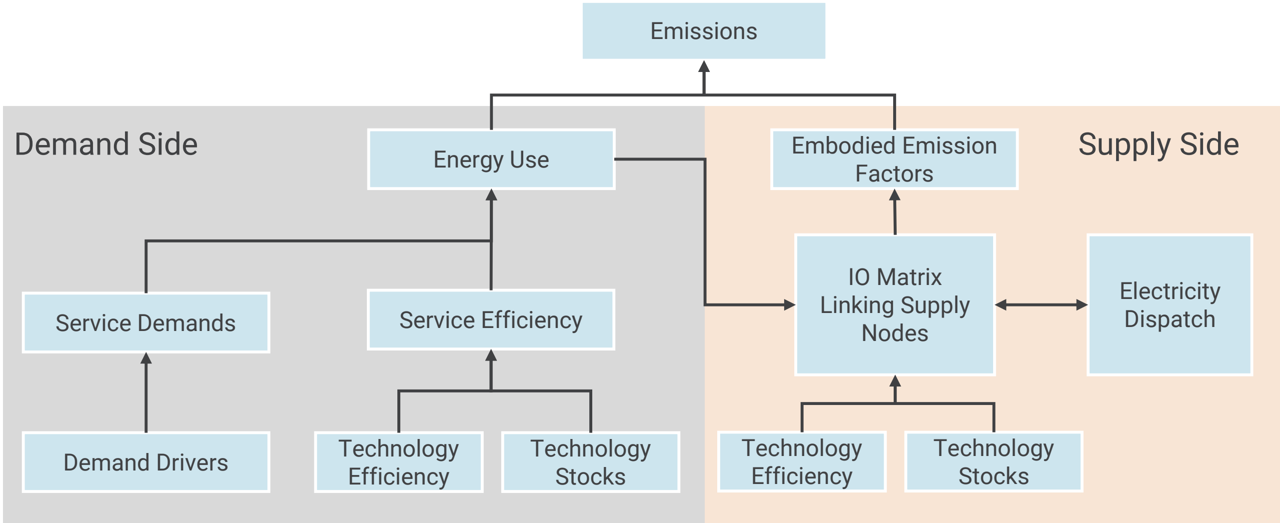
projections for future years are given, but if only historical data is available, EnergyPATHWAYS will use different regression techniques to project each variable across all model years.

Demand drivers are the basis for forecasting future demand for energy services. For example, if calculating the weight of laundry washed in residential households annually, a 10% increase in the demand driver, number of households, will result in a similar increase in the service demand, weight of laundry. Along with service demand, technology stocks that satisfy each service demand are tracked and projected into the future. The efficiency of each stock type for providing services is referred to as the service efficiency, fuel economy being a classic example. Total energy demand can be calculated by dividing service demand by service efficiency and summing across each service demand category, referred to in the model as demand subsectors. The demanded energy will be in one of many different fuel types (e.g. electricity or natural gas) depending on the technologies deployed and will be specific to a geography, customer category, and even hour of the year, as is the case with electricity.

Once energy use is calculated, the supply-side calculations of the EnergyPATHWAYS model begin. Mathematically supply-side calculations are done with an energy input output matrix that connects the flows of energy between supply nodes that produce or deliver energy. Input-output tables are frequently used by economists and in life-cycle assessment (LCA) work, and fundamentally calculations in EnergyPATHWAYS are no different though with several unique characteristics. First, the supply-side of the EnergyPATHWAYS proceeds one year at a time and the coefficients in the input-output matrix are updated annually as parameters in each supply node change. Second, in each calculation year, a detailed electricity dispatch is used to inform how much of each supply node goes into producing one unit of electricity (e.g. how much coal vs. gas) and how much new generation, transmission, and distribution capacity is needed for a reliable system. The inputs for electricity dispatch are derived from the rest of the supply side (e.g. heat rates of different power plants) and from the demand-side where hourly (8760) electricity profiles are produced. The electricity dispatch includes the ability to model long and short duration energy storage, thermal resources, hydroelectric plants, renewable resources, must-run generation, transmission, flexible load, and electric fuel production, such as hydrogen from electrolysis.

With the updated coefficients from the electricity dispatch and change in supply technology stocks, emissions factors [15] from each fuel type by location are calculated and combined with final energy demand to estimate emissions for future years. All renewable energy sources (solar, wind and hydro) are assumed to have an emissions factor of zero.

Figure 5. EnergyPATHWAYS model flow diagram for a calculation of energy system emissions.

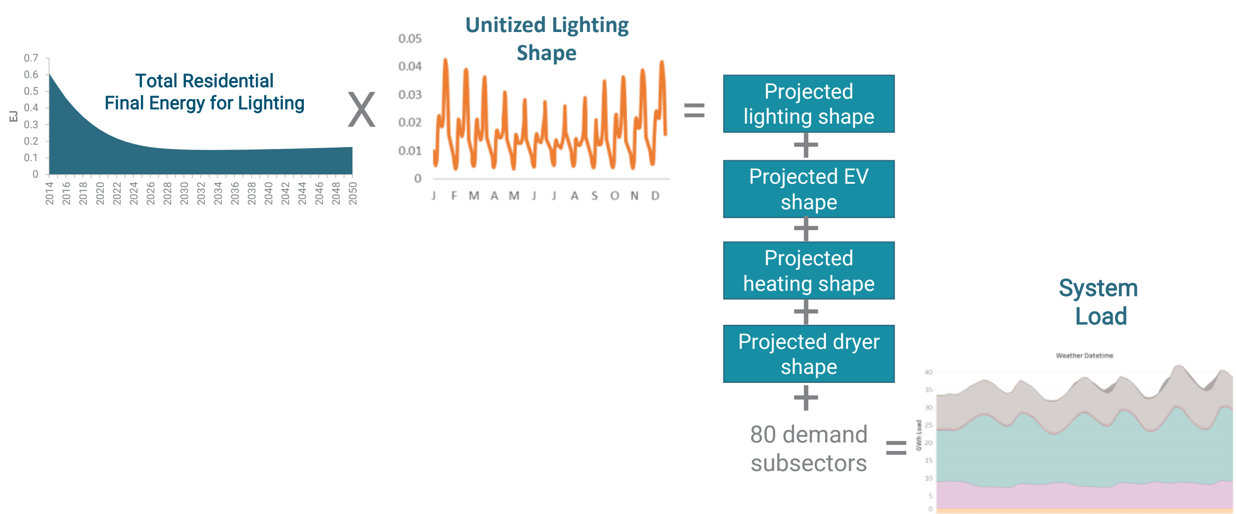


The above description of methodology gives a description of the supply and demand sides of EnergyPATHWAYS at a high level. The following section gives more detail on the electricity system representation that was used to evaluate the benefits of Northeast-HQ coordination.

Electricity Representation

The electricity dispatch starts on the demand-side of EnergyPATHWAYS with the buildup of subsector and technology-level load shapes, calibrated in a historical year to match a known top-down load shape. In future years, as the relative contributions of different end-uses change, the model will produce different end-use load shapes. So, for example, increases in electric space heating will cause larger winter peaks given the contribution of heating in winter hours. Likewise, the penetration of LED lighting will reduce the night-time peak due to their higher efficiency, as shown in Figure 6.

Figure 6 Process for constructing load shapes bottom-up to reflect underlying changes in the patterns for energy service demand.

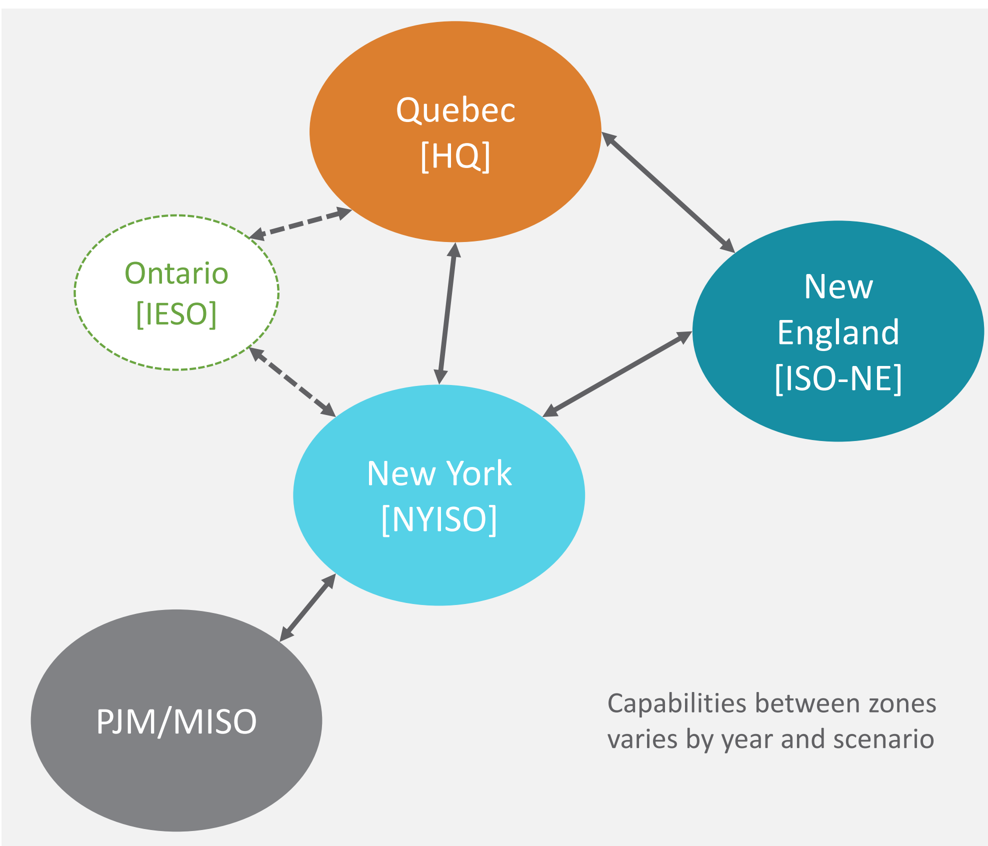


These subsector loads are aggregated to sectors and mapped to distribution feeder types, which are stylized representations of distribution equipment stocks that have both a revenue requirement and a marginal cost for increasing simultaneous peak load. In addition to these feeder-level loads, distributed generation such as combined heat and power (CHP) and distributed solar PV resources is included at the feeder-level.

The distribution feeder loads and resources are combined with a representation of the bulk transmission system that has loads, generators, and transmission ties between zones. The zonal topology used for this work is shown in Figure 7. Losses and hurdle rates between zones were used to more accurately represent transmission flows. Because Québec is its own interconnection and DC links are necessary for power flow to New York or New England, a loss rate of 6% was used, higher than the 4% assumed between New York and New England.

Loads and resources in Ontario were not explicitly modeled. Historically, Québec exports net energy to Ontario and Ontario exports net energy to New York. These net energy flows were maintained in future modeled years and scheduled endogenously, respecting existing transmission constraints.

Figure 7 Network topology in the EnergyPATHWAYS electricity dispatch optimization.



The dispatch of generators (including hydro), energy storage, flexible load, and transmission flows is solved in a linear optimization with a dispatch window of approximately one week. The optimization minimizes the operational cost to serve load across all zones and includes penalties on setting new distribution, transmission, or system generation peak loads[2].

The weekly energy budgets for long duration energy storage and hydro resources with inter-seasonal flexibility are solved in an initial optimization. Because of the size of the hydro reservoirs in Québec and operational flexibility, the resource was allowed to shift between months subject to an annual water budget and a seasonally specific minimum generation requirement[3]. Hydro in the U.S. was constrained by monthly budgets based on historical operations and minimum and maximum capacity constraints tied to this budget. Run-of-river hydro in the U.S. and Québec were modeled with a fixed profile shape.

Outputs from the electricity dispatch in EnergyPATHWAYS include hourly dispatch for all generators (thermal & storage), production costs, transmission flows, renewable curtailment, infrastructure requirements to maintain reliability, and updates to the input-outwork framework discussed prior.

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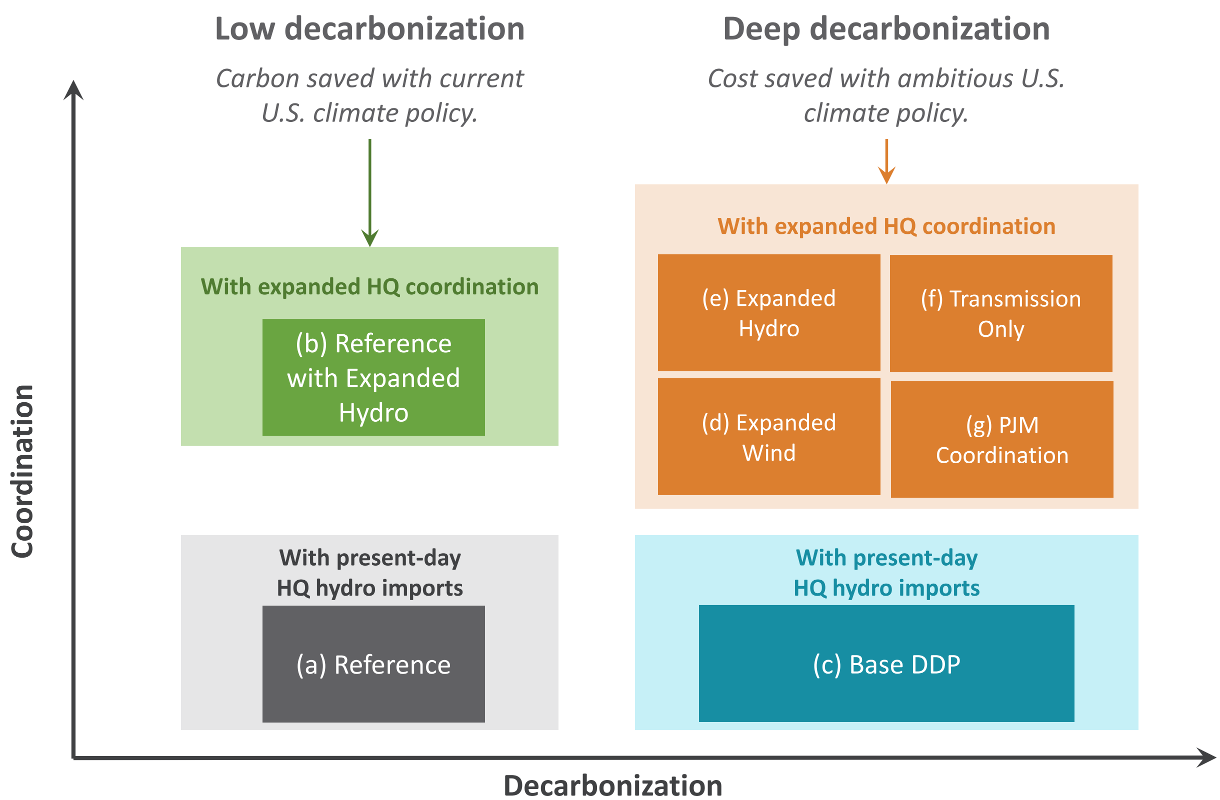
[2] One purpose for separating feeder loads from the bulk power system is to realistically constrain the behavior of distributed resources such as flexible load to provide balancing at the system level since such loads may be constrained on the distribution level.

[3] 50% of nameplate minimum generation requirement for Québec dispatchable hydro in May and June, and 30% in all other months

Scenarios

Seven scenarios are used to explore the implications of deep decarbonization and then the costs and benefits of increased coordination, shown in Figure 8. The scenarios are organized into four quadrants (shown in different colors). The two axes that create the quadrants are the degree to which the energy economy is decarbonized, and the degree of coordination between the Northeast and Hydro-Québec (NE-HQ). Costs and benefits are calculated by comparing one quadrant to another, with each comparison answering a different set of questions. As noted previously, the term *coordination* is used broadly to refer to both an increase in coordinated infrastructure (new transmission or resources in Québec to serve U.S. load) and changes to operations to reduce total system cost.

Figure 8 Scenarios to assess the costs and benefits of Northeast U.S. coordination with Québec under a variety of sensitivities including deep decarbonization pathways (DDPs)



Within the scenario matrix shown in Figure 8, the natural place to begin descriptions is with the Reference scenario (a), which is based on the EIA's 2017 *Annual Energy Outlook* (AEO) [16] with select updates as described in Table 5. The Reference scenario is designed to represent current energy policy in the U.S. All other study scenarios start with the Reference scenario (a) and then introduce changes on both the supply and demand sides of the energy system that get tracked using EnergyPATHWAYS. Table 4 lists the similarities and differences between scenarios by category. Most inputs and assumptions are common across all scenarios, only the deployment of technology and infrastructure differ.

Table 4 Contrasting similarities and difference between scenarios

	Constant across scenarios	**Differs across scenarios**
Drivers of energy consumption (e.g. population)		
Energy services (e.g. vehicle miles traveled)[4]		
Technology cost and performance		
Initial infrastructure & initial technology stocks		
Electricity dispatch settings (e.g. hurdle rates)		
Technology sales shares (e.g. heat pump sales)		
New energy infrastructure (e.g. new transmission)		

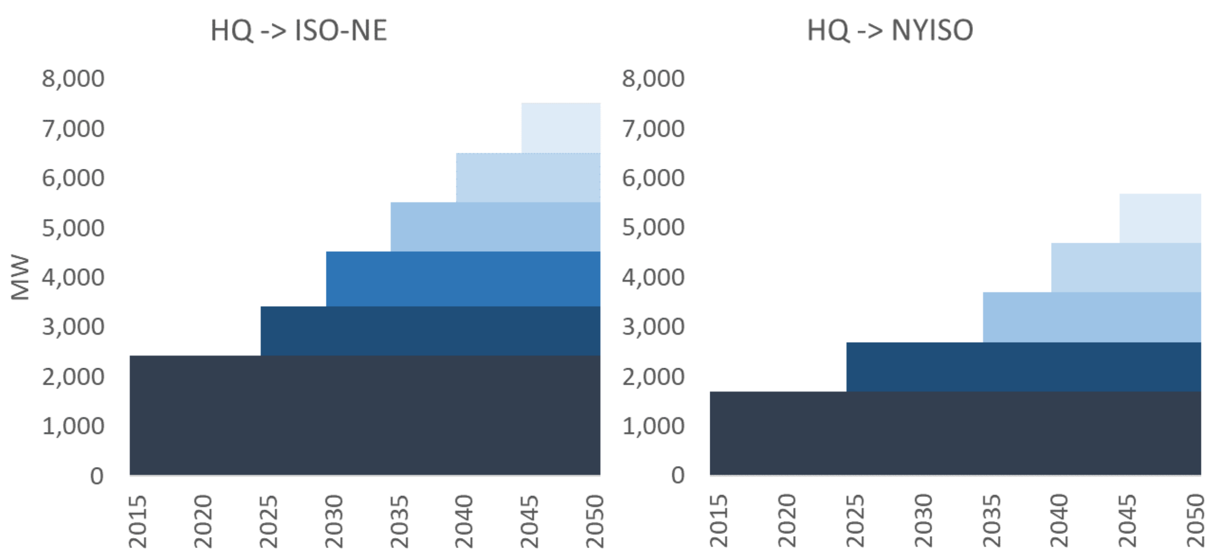
A summary of assumptions for the Reference scenario and the Reference with Expanded hydro scenarios is shown in Table 5. In Scenario (b) Northeast-HQ transmission ties are increased by 9 GW and an additional 30 TWh/year of hydro is built in Québec for export. The increase in resources for export start in 2025 and grow linearly to 2050, shown in Figure 9. By comparing scenario (a) with scenario (b) the GHG reduction from coordination under current policy is calculated. These values are input assumptions to the modeling and are not a result themselves. Each was selected after soliciting input from external advisors and after some modeling iteration to ensure the transmission ties were appropriate for the quantity and pattern of energy exports in a high renewables scenario.

[4] Equal energy services between all scenarios is a design principle used in the original U.S. DDPP scenarios to show that deep decarbonization is technically achievable without relying on conservation measures that are difficult to cost or validate in a modeling context.

Table 5 Summary of assumptions for the scenarios representing current U.S. climate policy.

	Current U.S. Climate Policy	
	(a) Reference	**(b) Reference with Expanded Hydro**
HQ exports to Northeast (TWh/yr)	**2015:** Hydro = 22.4 **2050:** Hydro = 22.4	Hydro = 22.4 Hydro = 52.4
HQ interconnection capacity to Northeast (MW)	Existing capacity: 4,115 MW	**Expanded** capacity: 2015 = 4,115; Post 2025 = 6,115; Post 2030 = 7,205; Post 2035 = 9,205; Post 2040 = 11,205; Post 2045 = 13,20 **+9,000 MW export capability**
Northeast inter-connection cap. to PJM & MISO (MW)	Existing 3,075 imports, 1,500 exports – consistent with NY long-term planning assumptions	
Nuclear Fleet (MW)	AEO 2017 projections* reflect Indian Point 2 & 3 retirements in 2020 & 2021. Capacity of 9,500 MW in 2015 decreases to 5,100 MW by 2050. * U.S. Department of Energy', *Annual Energy Outlook 2017.*	
Northeast non-hydro renewable energy (% of total generation)	-NY's Clean Energy Standard (50% of generation by 2030) -NY and Mass. Offshore Wind Mandates (2,400 and 1,600 MW, respectively)	
Eight-hour bulk battery storage (MW)	None	

Figure 9. Expanded HQ-Northeast coordination transmission build. Existing transmission capacity is increased by a factor of 3.2 by 2050, starting in 2025.



Load in Québec was assumed in all scenarios to grow by 0.42% per year for a total increase of 28.7 TWh between 2015 and 2050 [17]. Hydro-Québec was assumed in the modeling to build resources in the Reference and Base DDP scenarios to both satisfy internal loads and to maintain net exports to the region at present day levels (22.4 TWh). It was assumed through a combination of efficiency improvements on existing hydro generators and expected rainfall increase by 2050, due to climate change, a total of 15 TWh new hydro energy was possible at low cost and with no new impoundments [18]. In scenarios a, c, d, & f the remainder of energy to serve internal load came from onshore wind, and thus none of these scenarios were assumed to require new impoundments. Scenarios b, e, & g require new hydro from bins 2-4, as shown in Table 6.

Table 6 Assumed dispatchable hydro potential and cost in Québec[5]

Hydro Bin	Potential (TWh)	Levelized Fixed Cost ($/kW-yr)	Levelized Cost of Electricity ($/kWh)
1	157	Current: 106 Post-2030: 133	Current: 0.02 Post 2030: 0.025
2	10	372	0.07
3	10	531	0.10
4	15+	690	0.13

The Deep Decarbonization Pathways (DDPs), which make up the bulk of the scenarios match the stated GHG reduction ambition for most Northeastern states shown in Table 1. As noted, the steps for decarbonizing the economy are colloquially known as the *three pillars* and have been well documented in past studies [11, 9, 1, 12]. In brief, these pillars are: (1) using energy more efficiently; (2) switching energy end-uses from fossil fuels to electricity or electricity derived fuels (3) switching to zero-carbon electricity sources. Each pillar is mutually supporting – energy efficiency reduces costs and the scale of infrastructure build that would otherwise be required – fuel switching reduces direct GHGs from transportation, buildings, and industry that are large in aggregate – and carbon free energy in electricity eliminates upstream emissions from electrification. Together they create a cohesive strategy to meet 2050 (and beyond) GHG reduction goals, and based on this and past studies, without need for early retirements and with reasonable cost [1].

Within the three-pillar framework, multiple different technology pathways exist that reach carbon reduction targets [1]. For this study, a single technology pathway is highlighted and sensitivities with respect to Northeast-HQ coordination conducted. The Base DDP was designed to be the technological and political frontrunner among stakeholders and is characterized by high wind and solar penetrations with energy storage, battery electric vehicles in transportation, and electrification of heating in buildings using heat pumps. Biomass supplies are used to partially[6] decarbonize the pipeline to provide a low carbon fuel for industry & electricity and to create biodiesel for heavy duty transportation. We note here that this represents one of many possible technology pathways to deep decarbonization and each will show a different set of benefits from

[5] Current dispatchable hydro is 144 TWh. The remainder of hydro bin one requires no new impoundments but instead comes from efficiency improvements and a wetter climate by 2050.

[6] Pipeline gas and diesel fuel usage remains too large for available biomass to completely displace.

Northeast-HQ coordination. A further phase of this work could be used to explore these in more detail[7].

The detailed summary of DDP scenario assumptions are shown in Table 7. Scenarios (d) through (g) are Northeast-HQ coordination sensitivities on the Base DDP scenario (C). For all DDP scenarios, the steps taken to decarbonize the demand-side are identical with benchmarks for the most important subsectors shown below and discussed in the Deep Decarbonization Scenario Results.

All expanded coordination scenarios (d) through (g) include 9 GW of expanded transmission by 2050, matching the magnitude and timing of expansion in the Reference with Expanded Hydro scenario and shown in Figure 9. Each coordination sensitivity instead differs with respect to the type of resources built in Québec.

The Expanded Wind scenario includes 30 TWh of new wind exports. The Expanded Hydro and PJM Coordination scenarios both involve an equal amount of energy exports, but from new dispatchable hydro. The Transmission Only scenario instead keeps existing net energy exports from Hydro-Québec (matching the Base DDP) but still adds the new transmission, the purpose of which is to determine the value of balancing high levels of renewables using both imports from and exports to HQ absent any additional energy.

The PJM Coordination scenario is distinguished through an additional 3 GW of import/export capability between NY and PJM. The purpose of this scenario is to show how the benefits of increased Northeast-HQ coordination change as competing transmission ties between the Northeast and the rest of the U.S. are strengthened.

[7] Alternatives that maintained more electricity supply flexibility (nuclear or carbon capture and storage) or introduced higher demand for seasonally flexible loads (hydrogen electrolysis) would help reduce the need for or fill the niche that Hydro-Québec coordination plays in scenarios d-g. Such scenarios could be more costly, risky, or deemed worse for other reasons, and thus, may be less optimal overall.

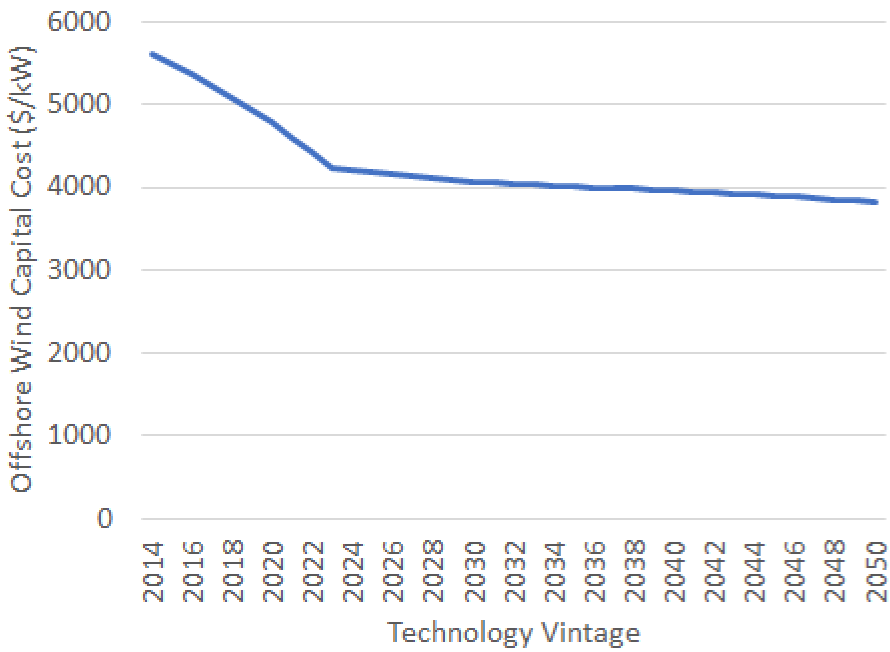
Table 7 Summary of assumptions for the deep decarbonization pathways scenarios.

	DDP reaches 80% Reduction in CO_2 Emissions by 2050				
	(c) Base DDP	**(d) Expanded Wind**	**(e) Expanded Hydro**	**(f) Transmission Only**	**(g) PJM Coordination**
HQ exports to Northeast (TWh/yr)	**2015:** Hydro = 22.4 **2050:** Hydro = 22.4	Hydro = 22.4 Hydro = 22.4 Wind = 30	Hydro = 22.4 Hydro = 52.4	Hydro = 22.4 Hydro = 22.4	Hydro = 22.4 Hydro = 52.4
HQ interconnection capacity to Northeast (MW)	**Existing** capacity: 4,115 MW	**Expanded** capacity: 2015 = 4,115; Post 2025 = 6,115; Post 2030 = 7,205; Post 2035 = 9,205; Post 2040 = 11,205; Post 2045 = 13,20 **+9,000 MW export capability**			
Northeast inter-connection cap. to PJM & MISO (MW)	Existing 3,075 imports, 1,500 exports – consistent with NY long-term planning assumptions				Additional 3,000 MW of import/export
Nuclear Fleet (MW)	AEO 2017 projections* reflect Indian Point 2 & 3 retirements in 2020 & 2021. Capacity of 9,500 MW in 2015 decreases to 5,100 MW by 2050. * U.S. Department of Energy', *Annual Energy Outlook 2017.*				
Northeast non-hydro renewable energy (% of total generation)	Wind : Onshore = 15% Offshore = 48% Solar PV = 15% **Subtotal = 78%**	Wind : Onshore = 15% Offshore = 40% Solar PV = 15% **Subtotal = 70%**		Wind : Onshore = 15% Offshore = 48% Solar PV = 15% **Subtotal = 78%**	Wind : Onshore = 15% Offshore = 40% Solar PV = 15% **Subtotal = 70%**
Eight-hour bulk battery storage (MW)	NYISO = 15,000 MW ISO-NE = 15,000 MW **Total = 30,000 MW**				
Space heating	Commercial space heating 59% of 2050 service met with electricity vs 45% in scenario (a) reference Residential space heating 42% of 2050 service met with electricity vs 14% in scenario (a) reference				
Water heating	Commercial water heating 90% of 2050 service met with electricity vs 7% in scenario (a) reference Residential water heating 92% of 2050 service met with electricity vs 32% in scenario (a) reference				
Vehicles	80% battery electric vehicles (BEV), 20% plug in hybrid electric vehicles (PHEV) for 2050 LDV stock 59% BEV for 2050 MDV stock 57% BEV for 2050 HDV stock				

The final feature of DDP scenarios with expanded Québec resources for exports (d, e, and g) is the reduction in offshore wind in New England and New York that is displaced (reduced from 48% to 40% of the total generation mix), which represents the most expensive portion (further along the supply curve) of offshore wind resources in the Atlantic. The quantity of onshore wind is at its achievable potential [19] and remains constant, as does solar PV. Even after being reduced, offshore wind is the largest source of electrical energy, and could present a major deployment challenge across all scenarios.

The cost of offshore wind has two components in the modeled scenarios. First is the base cost of the turbines themselves and second is the cost to provide interconnection with load. The source of cost estimates for the base capital costs is the NREL Baseline Cost and Performance Data for Electricity Generation Technologies shown in Figure 10 [20].

Figure 10 Assumed offshore wind cost through 2050 vintage



The interconnection cost is reflected in a supply curve from EPA MARKAL produced using GIS analysis from NREL. The underlying transmission cost assumptions were from NREL's Renewable Electricity Futures Study [21] and are shown in Table 8.

Table 8. Transmission component cost assumptions (2005 dollars)

Cost Category	Cost	Unit
Base Transmission Cost	2,170	$/MW-mile
Grid Connection Cost	103	$/kW
Connect to: Substation	23.1	$/kW
Connect to: Load Center	23.1	$/kW
Connect to: Trans. Line	35.6	$/kW

All renewable profiles are simulated to match load data from a 2011 weather year and come from NREL's Wind Toolkit and the National Solar Radiation Database.

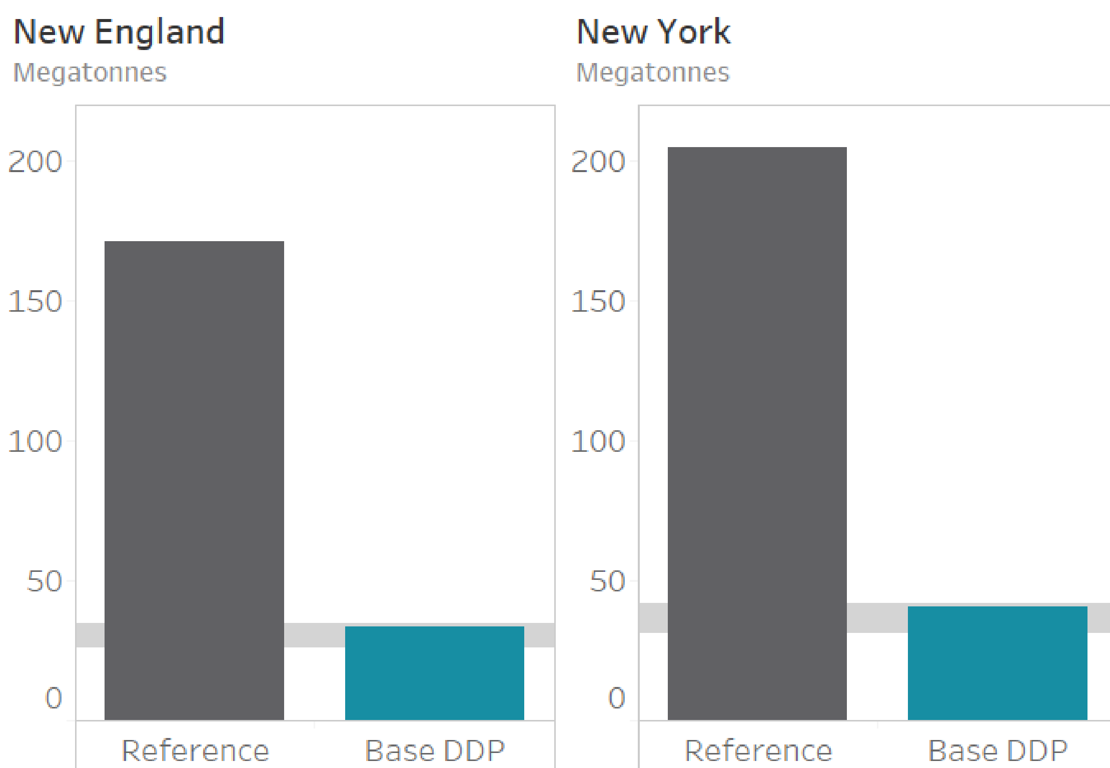
Deep Decarbonization Scenario Results

This section summarizes the emissions, energy demand and energy supply results for the Reference and Base DDP scenarios, which project business-as-usual levels of coordination between HQ and the Northeast. We describe the transformation of the Northeast's energy system to achieve steep reductions in energy-related CO_2 emissions, and present detailed results of the electricity system, including installed capacity, load and hourly operations.

Emissions

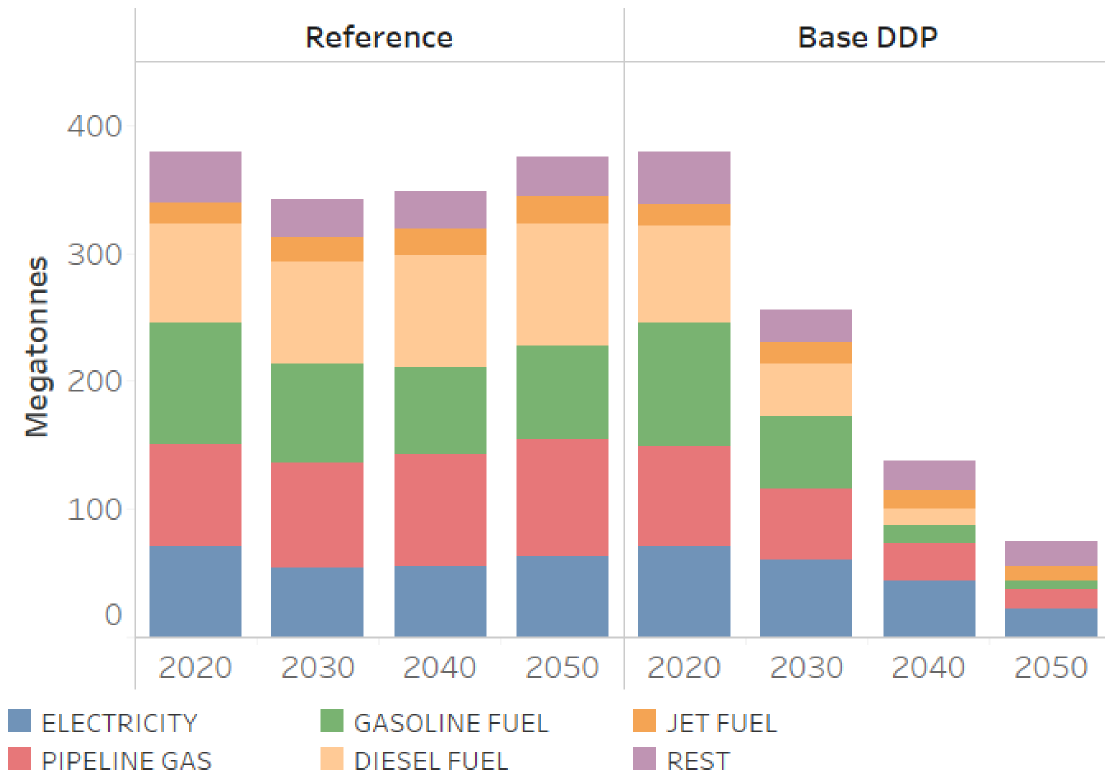
Figure 11 summarizes energy-related CO_2 emissions results in 2050 for New England and New York. Although existing energy policies in the Northeast support renewable resource development, emissions in the Reference Case for both regions are substantially higher than the study's GHG target (80 to 85 percent reduction below 1990 levels by 2050), which is shown as a grey band in the figure. The Base DDP Case reduces emissions in both regions to levels consistent with the study's GHG target.

Figure 11. Energy-related CO2 Emissions by Scenario in 2050



Emissions reductions in the Base DDP Case follow the suite of strategies deployed across the energy supply and demand sectors, including: (a) energy efficiency; (b) switching end-uses from fossil fuels to electricity; (c) decarbonizing electricity generation; and (d) reducing the carbon intensity of liquid fuels with bioenergy. These strategies are apparent in Figure 12, which shows CO_2 emissions in the Northeast by energy type over time. In the Base DDP Case, electricity-related emissions decrease as onshore wind, offshore wind, solar PV and hydroelectric resources are deployed at scale and integrated into New York and New England's electricity systems. Electrifying space and water heating in buildings results in a decrease in pipeline gas emissions, while the large decline in gasoline emissions by 2050 is a result of light-duty vehicles running almost entirely on electricity. Emissions from diesel are eliminated by 2050 through a combination of: (a) switching fuel oil for space heating to electricity; (b) adopting diesel hybrid heavy-duty vehicles; and (c) using renewable diesel to supply the remaining demand for diesel fuel.

Figure 12. Northeast Energy-related CO2 Emissions by Fuel Type



Energy Demand

Reference Case final energy demand is projected to increase from approximately 5,800 TBtu today to 6,100 TBtu in 2050, a 6 percent increase, as shown in Figure 13. Drivers of energy use, such as population economic activity, all grow through 2050, but their impact on energy consumption is moderated through baseline efficiency improvements. Final energy demand in the Base DDP Case is 3,700 TBtu by 2050, which is 35 percent below today's level, and this reduction is a result of energy efficiency and fuel switching strategies deployed across all sectors of the economy.

Figure 13. Northeast Final Energy Demand

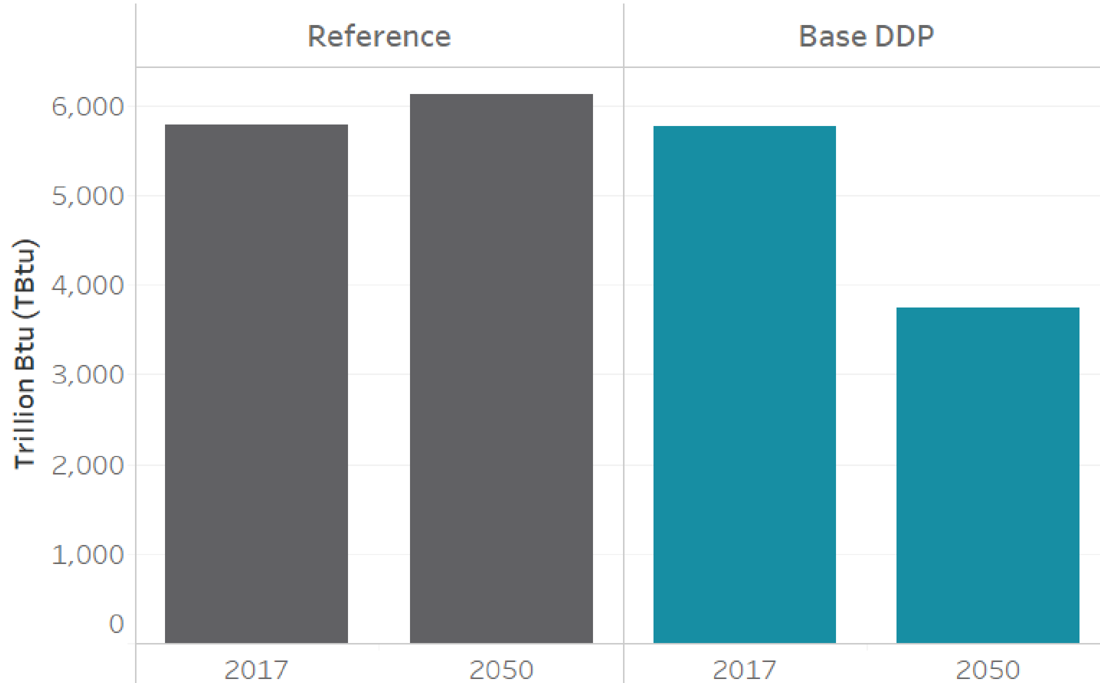
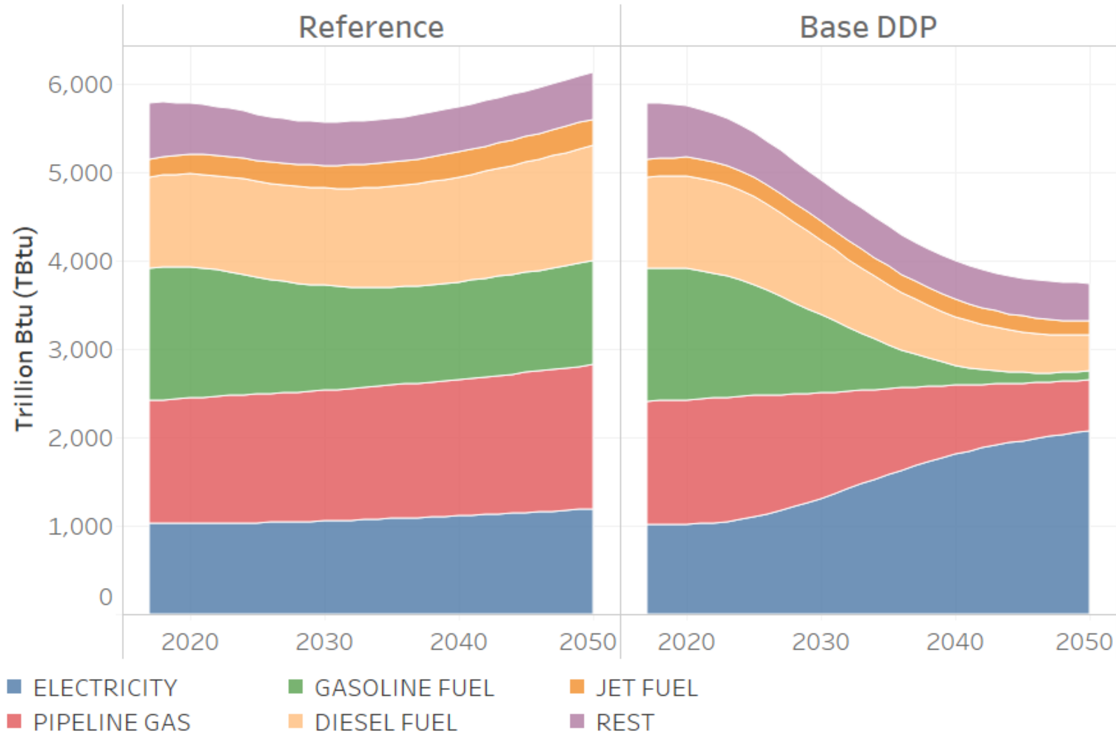


Figure 14 shows energy demand disaggregated by final energy type, including electricity, pipeline gas and various petroleum products. In the Reference Case, gasoline consumption decreases over time due to fuel economy improvements, which helps offset growth in demand for other fuels. Electricity consumption doubles by 2050 relative to today's level in the Base DDP Case largely due to the electrification of: (a) passenger transportation; and (b) space and water heating in residential and commercial buildings. As a result, gasoline and pipeline gas consumption decreases by approximately 90 and 60 percent respectively by 2050. Demand for diesel, a liquid fuel primarily used for residential space heating and freight transportation, declines by 60 percent by 2050 relative to today.

Figure 14. Northeast Final Energy Demand by Fuel Type



Changes to the total and composition of energy demand over time are a result of the physical stock of demand-side equipment in the Northeast turning over to low-carbon and efficient equipment. The figures below illustrate the evolution of the equipment stock (left-hand side) and energy demand (right-hand side) for residential space heating and light-duty vehicles in the deep decarbonization cases. Figure 15 shows the transition for residential space heating, where today's equipment stock is largely gas- and distillate-fired furnaces and radiators. The primary decarbonization strategy is to switch from fossil fuel-fired equipment to electric air- and ground-source heat pumps, which currently have relatively low penetrations in the Northeast. The total residential heating stock is approximately one-quarter electric by 2030, two-thirds by 2040 and nearly 90 percent by 2050. Overall energy demand for space heating declines due to the higher efficiency of heat pumps relative to furnaces and radiators.

Figure 15 Base DDP Case Residential Space Heating Transition

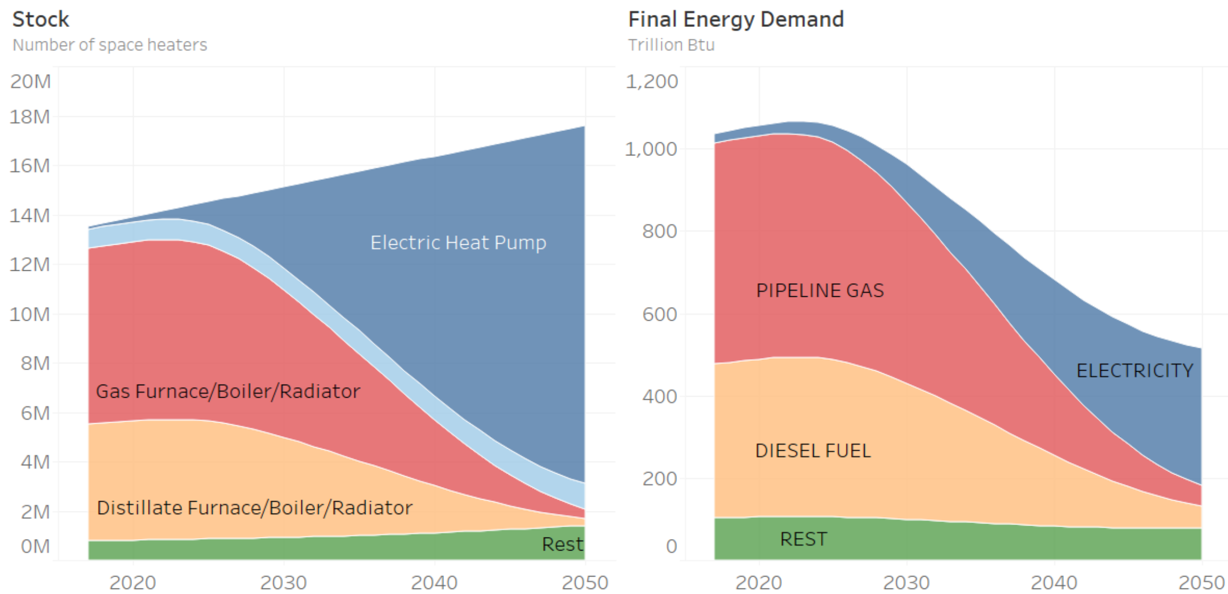
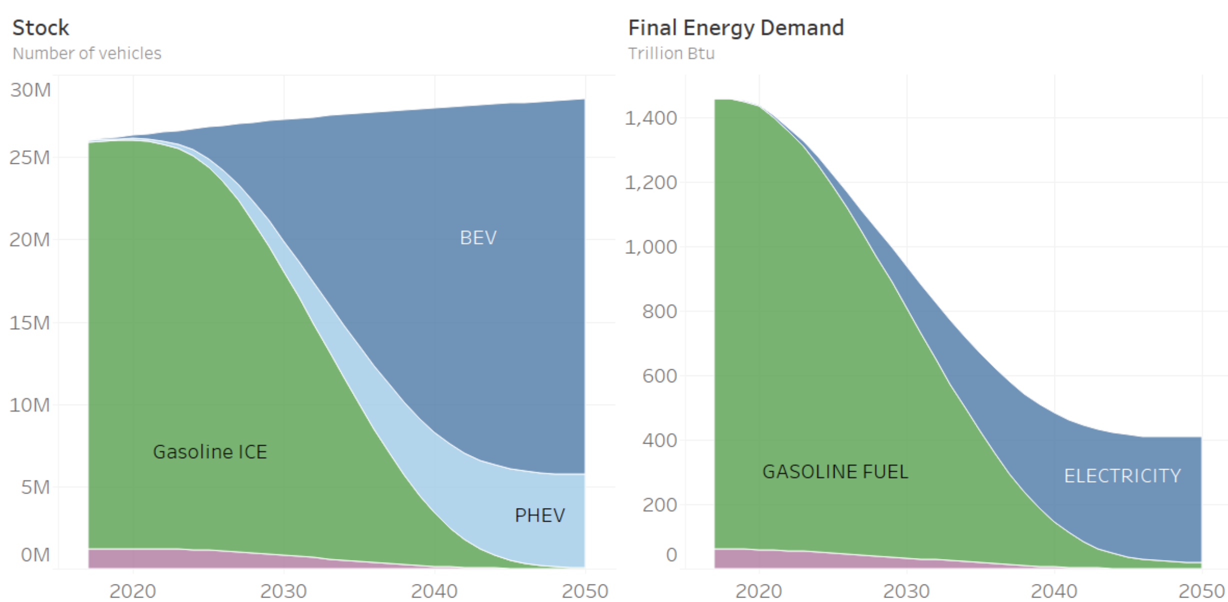


Figure 16 shows the transition for the light-duty vehicle fleet, which today is overwhelmingly gasoline internal combustion engine vehicles. By the mid-2030s, 80 percent of light-duty vehicle sales are battery electric vehicle (BEV) and 20 percent are plug-in hybrid electric vehicle (PHEV). However, there is a lag between vehicle sales and the composition of vehicles on the road, and the stock of light-duty vehicles is not entirely BEV/PHEV until 2050. Electrifying passenger transportation results in almost zero petroleum consumption by 2050, and overall energy demand is less than one-third of today due to the efficiency of battery electric powertrains relative to an internal combustion engine.

Figure 16. Base DDP Case Light-Duty Vehicle Transition

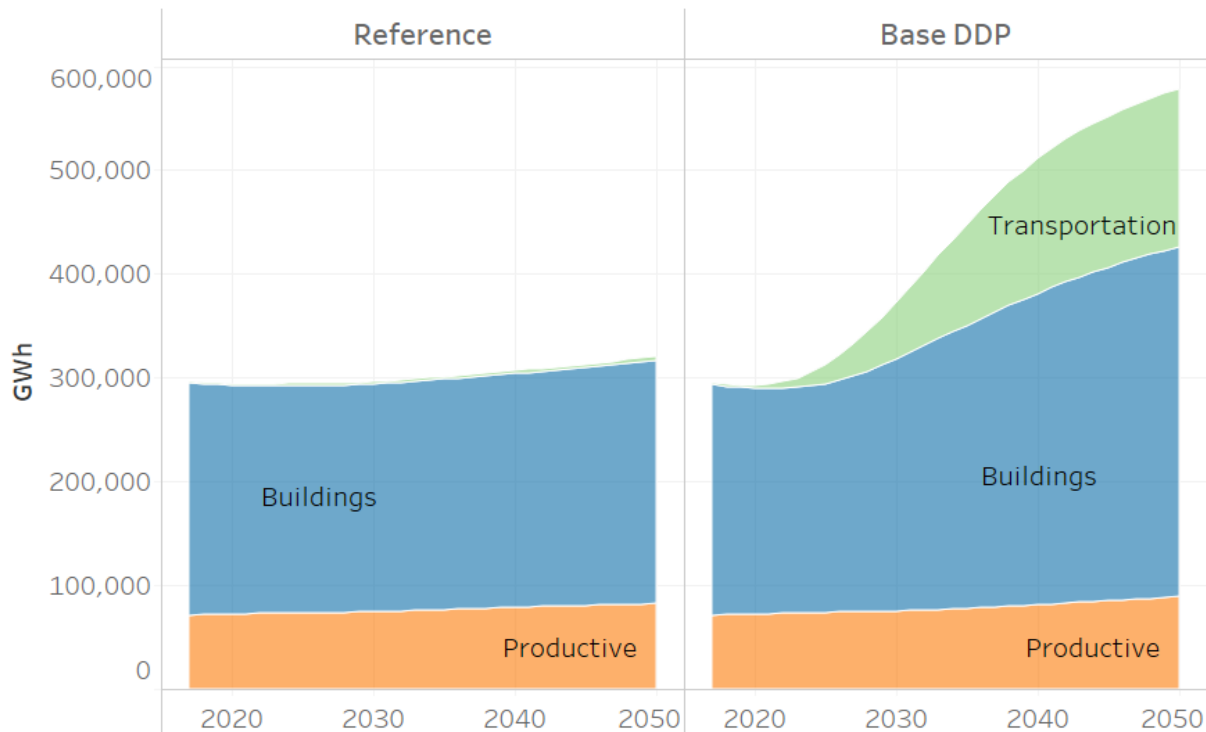


Electricity

Load

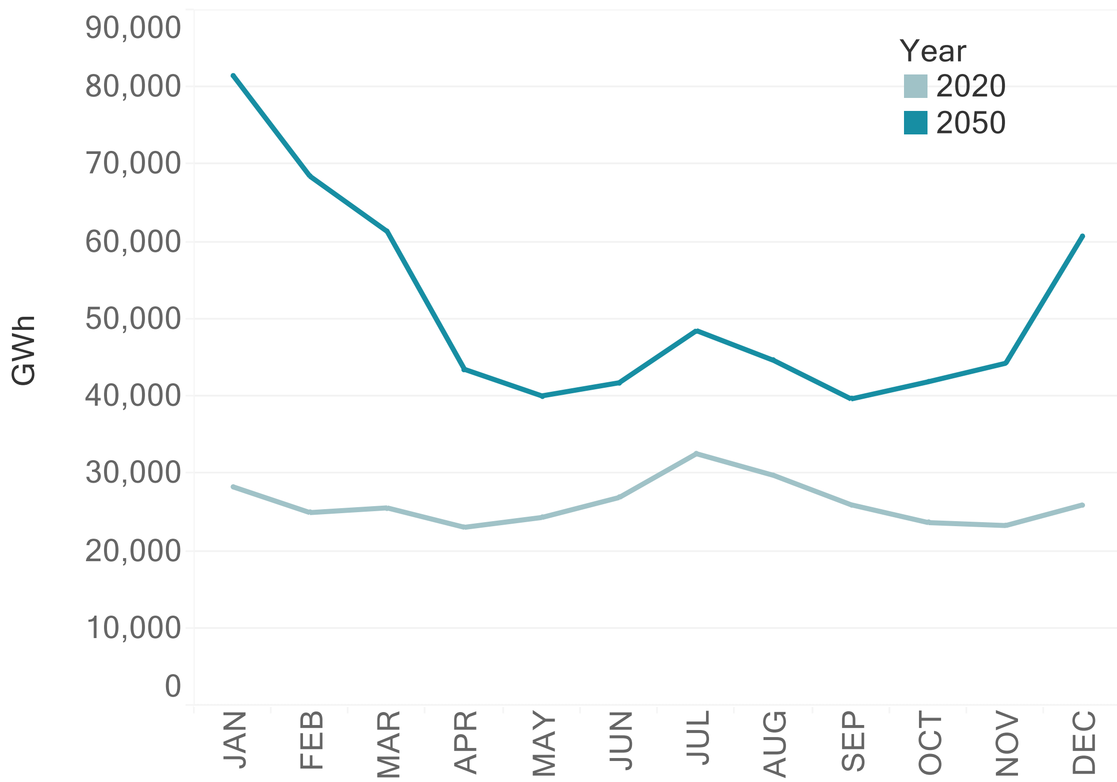
Figure 17 compares the trajectory of retail electricity scales for the Reference Case against the Base DDP Case. Retail electricity sales in this figure are shown by demand sector (buildings, industrial and transportation) and they account for electrification, energy efficiency and behind-the-meter generation. Reference Case electricity sales grow by approximately 0.2 percent per year from 2017 to 2050, reflecting a continuation of stagnant load growth experienced in recent years. In contrast, electricity sales grow by more than 2.0 percent per year in the Base DDP Case due to the electrification of transportation and space and water heating in buildings.

Figure 17. Northeast Retail Electricity Sales



In addition to increasing overall load requirements, electrification in the Base DDP Case changes the seasonal characteristics of electricity consumption. Figure 18 shows monthly electricity consumption for the years 2020 and 2050 in the Northeast. Today, electricity consumption is highest during the summer due to air conditioning loads, but the transition from natural gas- and fuel oil-fired furnaces to electric heat pumps results in a dramatic increase in wintertime electricity consumption. Other uses of electrification, particularly electric vehicle adoption, increase overall load requirements, but they do not have as strong a seasonal effect as space heating. By 2050, the seasonal shape of electricity consumption in the Northeast mirrors that of Québec, which already relies largely on electricity for heating.

Figure 18. Base DDP Case Monthly Electricity Consumption for the Northeast



Peak demand for the ISO-NE and NYISO electricity systems substantially increases by 2050 in the Base DDP Case, as shown in Figure 19. The 2050 system peak is more than twice today's peak demand, and the season where the highest load hours occur shifts from the summer to the winter (see Figure 20). The growth in annual energy and peak demand in the Northeast highlights several electricity system planning dynamics in pursuit of realizing deep decarbonization goals. First, annual energy requirements require carbon-free electricity supply beyond what is needed under a business-as-usual load forecast. Second, growth in peak demand requires additional resources to achieve resource adequacy. Third, the shift in the season where peak demand is realized emphasizes the need for resources that are available to generate during winter cold spells.

Figure 19. Annual Peak Demand

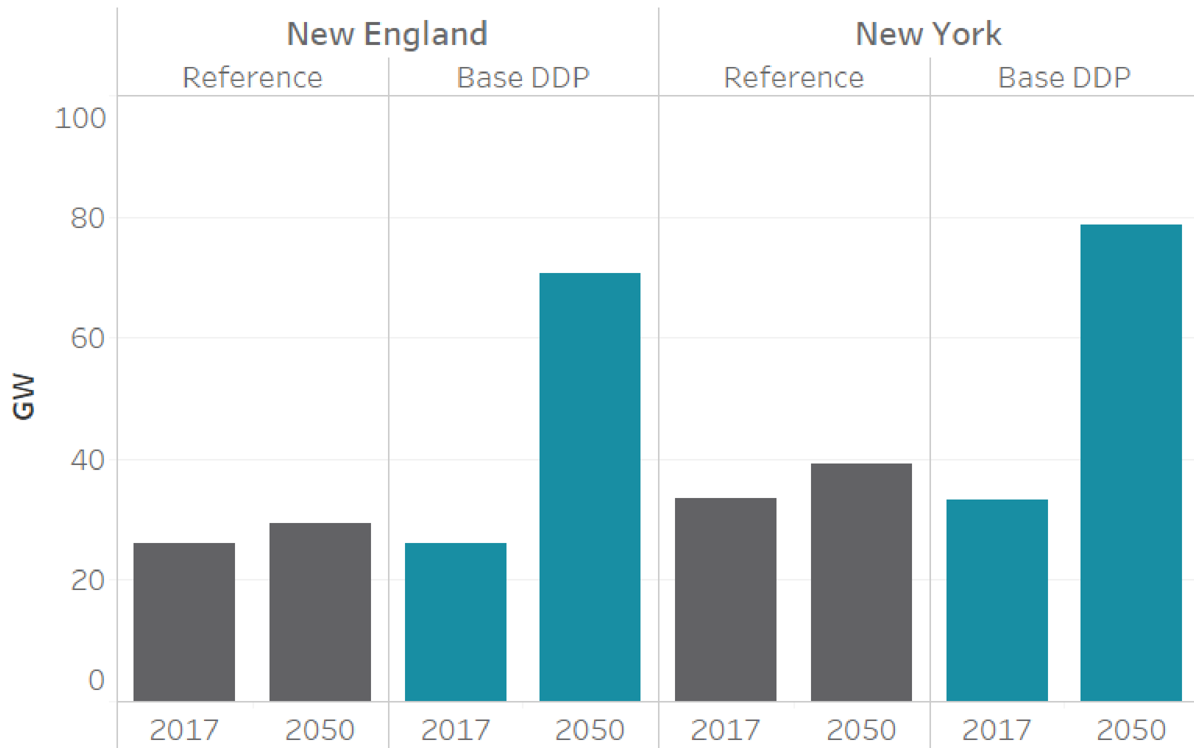
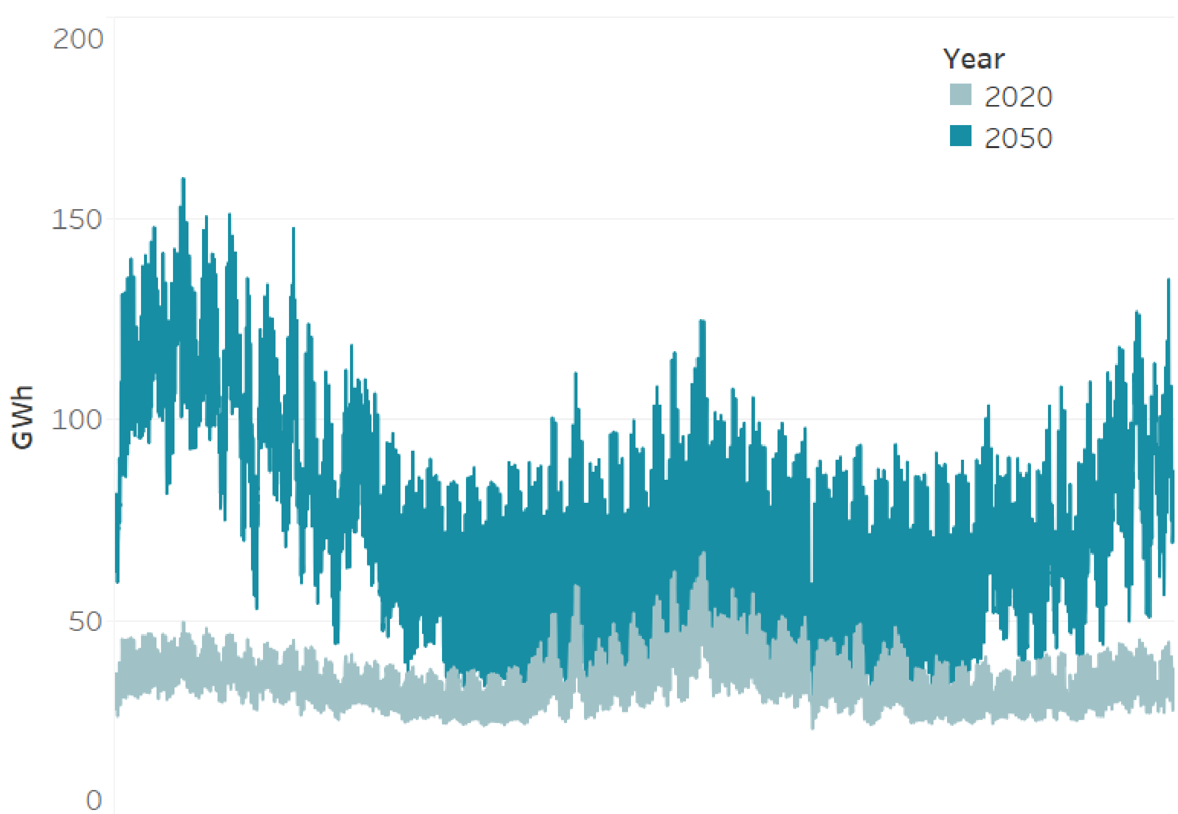


Figure 20. Northeast Hourly Load, Primary DDP



Resources

Figure 21 shows the 2050 generation mix by technology, including: (a) generation from supply-side resources located in the Northeast; (b) discharge from pumped hydro and battery energy storage resources ("storage discharge") in the Northeast; and (c) gross imports from neighboring interconnected regions (HQ, IESO and PJM). The Base DDP Case's generation requirement is approximately double Reference Case levels primarily due to aggressive electrification described above. In addition, generation exceeds transmission-level load, because a portion of generation is eventually curtailed due to the very high levels of inflexible resources (wind, solar, nuclear). Approximately eighty-five percent of the generation mix is completely carbon-free, but, since half of the fuel input for thermal generation is renewable natural gas (RNG), more than 90 percent of generation produces zero-net-CO_2 emissions.

Figure 21. Northeast Electricity Generation by Technology in 2050

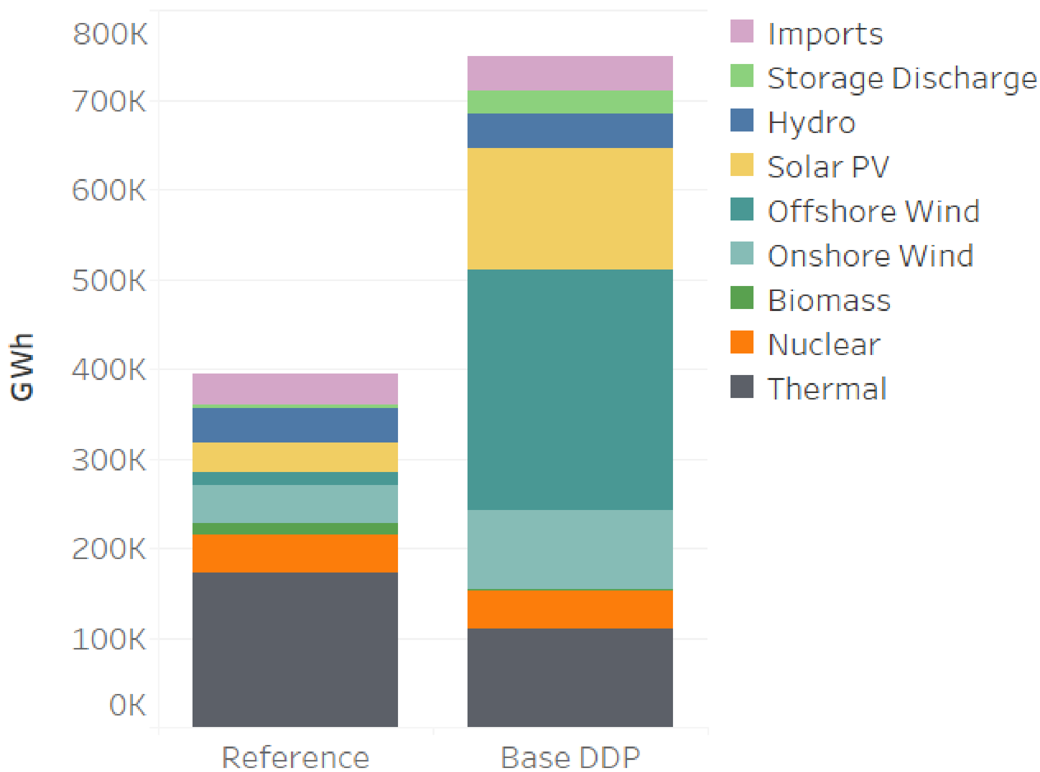
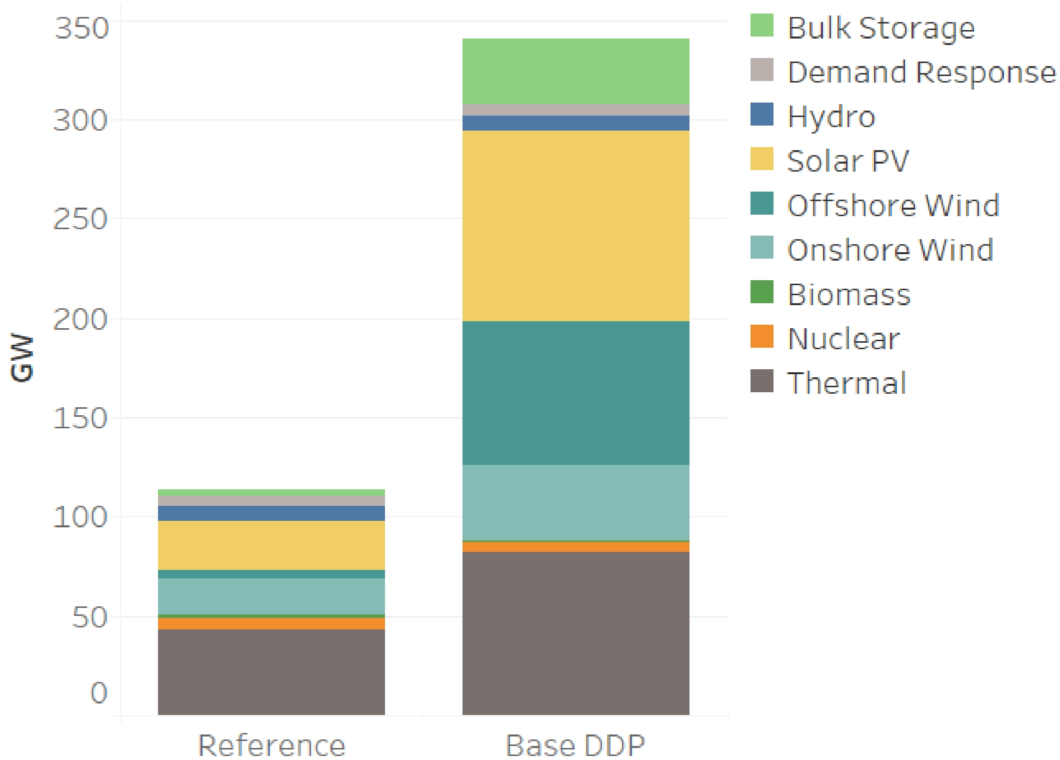


Figure 22 summarizes the Northeast's installed capacity mix by technology in 2050. Installed capacity requirements are three times higher in the Base DDP Case relative to the Reference Case due to: (a) increased energy demand from electrification; (b) growth in peak demand, which requires additional peaking thermal capacity that operates infrequently; (c) relatively low capacity factors for renewable resources, particularly solar PV (i.e., less than 20 percent); and (d) battery energy storage resources to integrate generation from inflexible resources. Offshore wind capacity is more than 72 GW by 2050, while the installed capacity of utility-scale and rooftop solar PV resources increases to nearly 100 GW.

Figure 22. Northeast Installed Generation Capacity, 2050



Operations

Figure 23 to Figure 25 shows dispatch profiles by season and hour for the Base DDP Case in 2050, where the top panel of each figure shows the average electricity consumption and the bottom panel shows average generation.[8] These figures illustrate how electricity demand and generation vary across seasons, and periods where inflexible generation exceeds load, resulting in curtailment. In New England and New York, loads are highest during the winter due to the electrification of space heating, but generation from wind, solar and hydro resources during the season is insufficient to meet demand in all hours, resulting in thermal resources operating during most hours. In contrast, thermal resources operate infrequently during the spring and fall, because load is relatively low and renewable output is high, which results in pervasive curtailment of renewable generation (red portion in the top panel) even after accounting for the flexibility provided by various balancing resources, such as 30 GW of energy storage across New England and New York.

[8] Seasons are defined as: Winter is December – February; Spring is March – May; Summer is June – August; and Fall is September – November.

Figure 23. New England, Base DDP Case, 2050

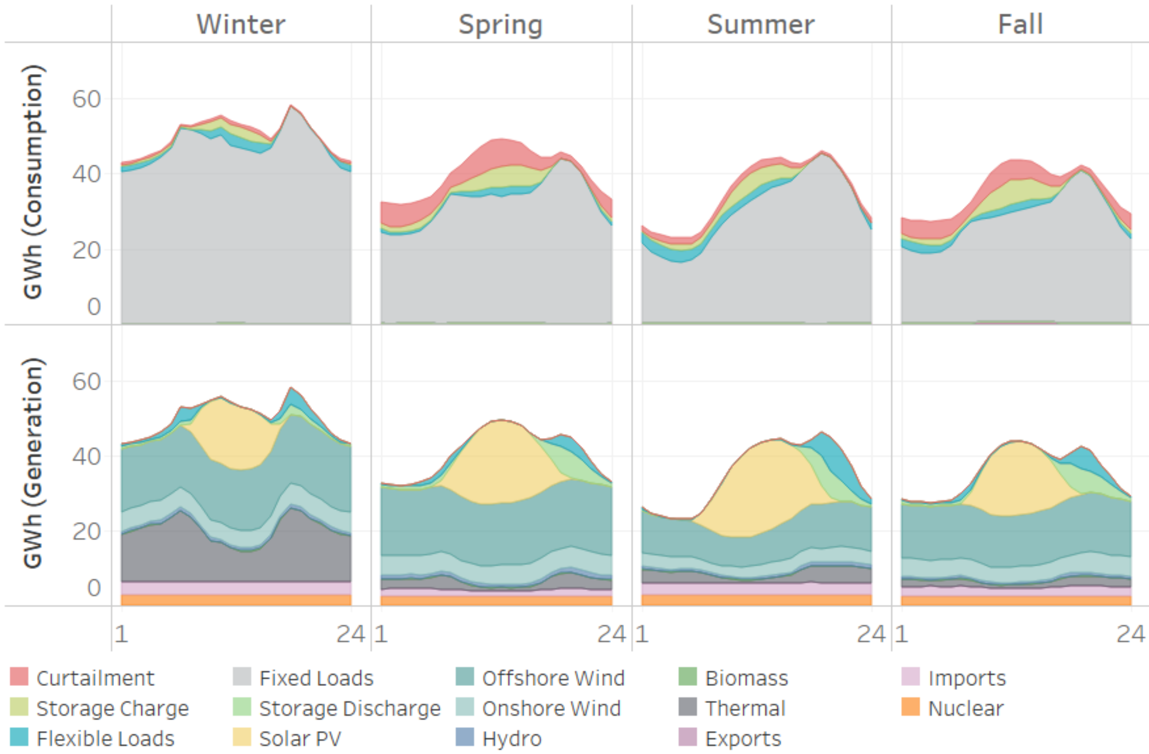


Figure 24. New York, Base DDP Case, 2050

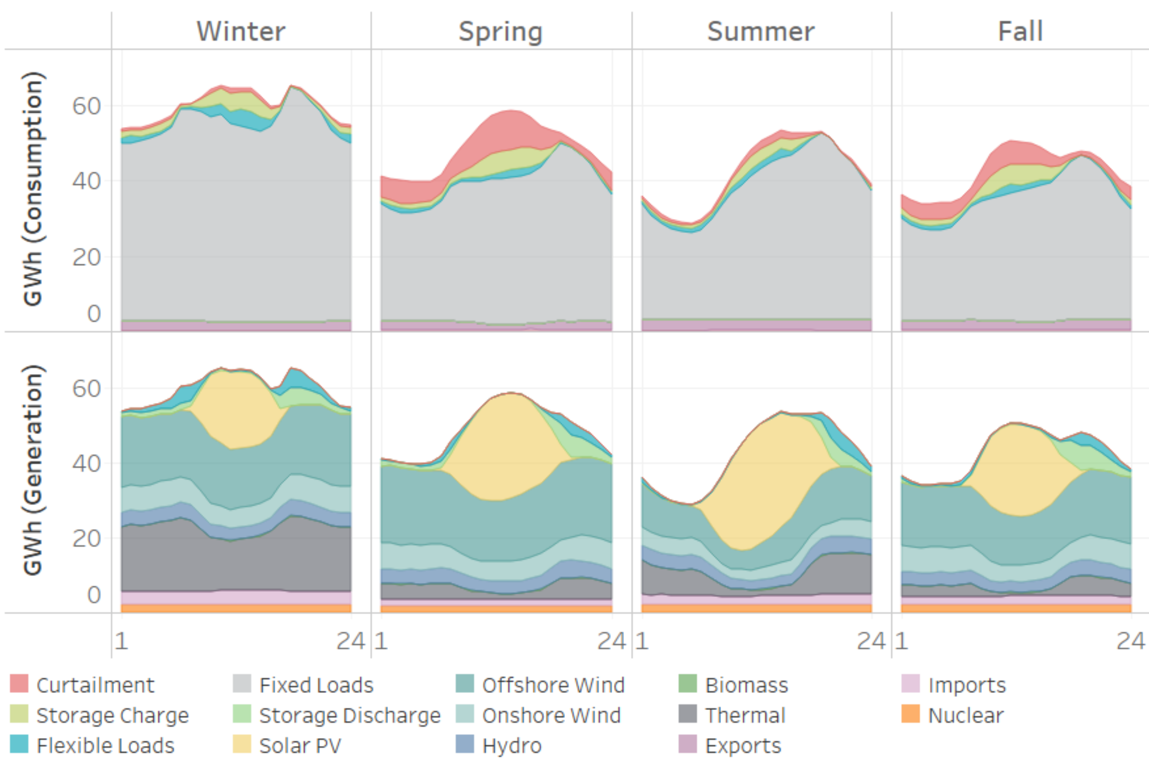
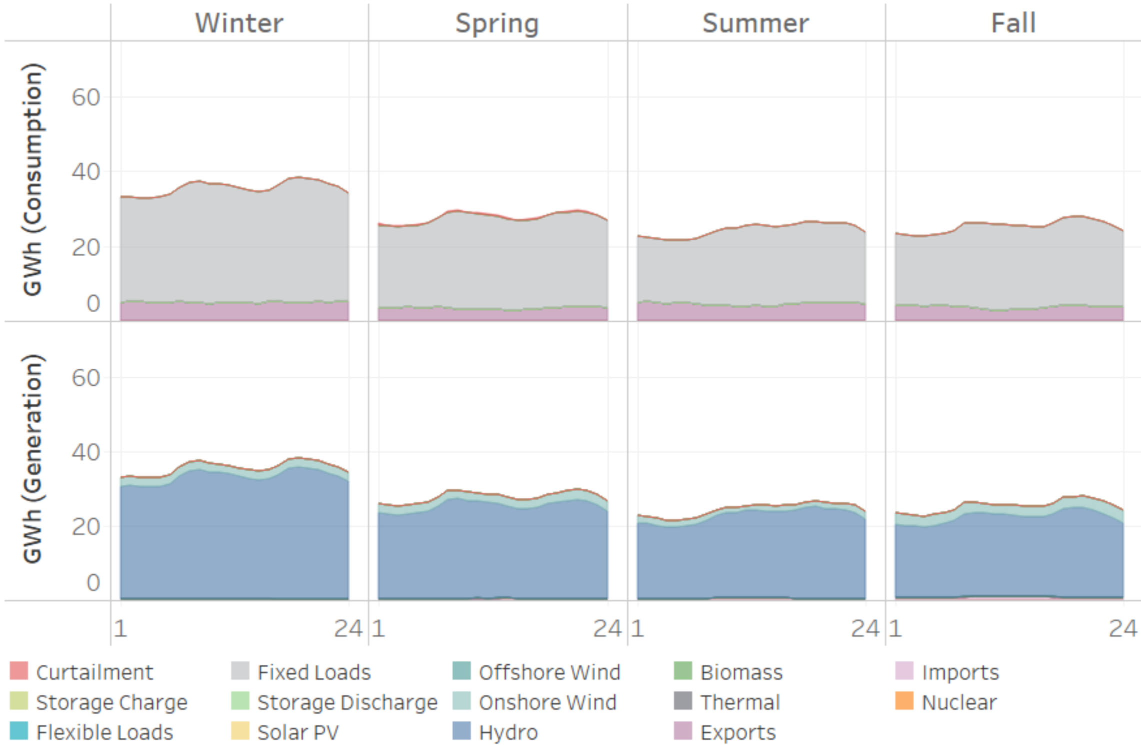


Figure 25. Québec, Base DDP Case, 2050



Expanded Coordination Scenario Results

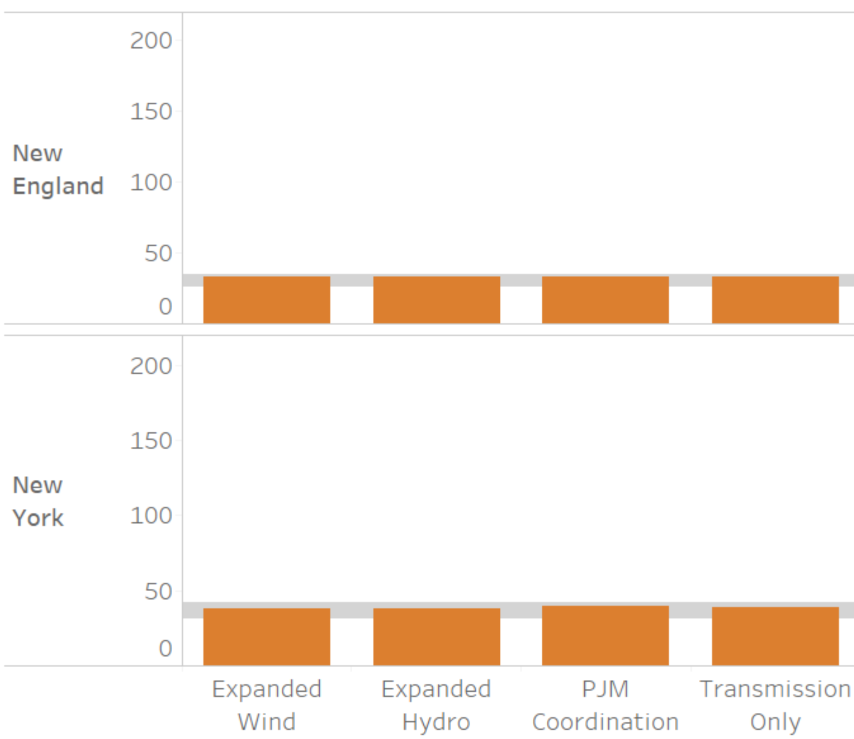
Overview

This section summarizes results for scenarios with expanded coordination between HQ and the Northeast. We report results for the electricity system, as well as economic cost and benefits results for four deep decarbonization cases that incorporate expanded transmission and/or resources, including:

- **Expanded Wind Case**: 30 TWh of new onshore wind resources are developed in Québec;
- **Expanded Hydro Case**: 30 TWh of new hydro resources are developed in Québec;
- **Transmission Only Case**: only transmission capacity is expanded without any corresponding new, clean electricity generation on the Québec side; and
- **PJM Coordination Case**: 30 TWh of new hydro resources are developed in Québec, and the Northeast similarly pursues coordination with PJM through an additional 3,000 MW of transmission capacity

All four scenarios reduce emissions in New England and New York to levels consistent with the study's GHG target, as shown in Figure 26. Outside of the electricity sector, energy-related CO_2 emissions are equivalent in the increased coordination scenarios as the Base DDP Case, and energy demand across all fuel types reported in the section above is also the same. The scenarios are differentiated by their impacts on electricity supply, system operations and economic outcomes, which are described in detail below.

Figure 26. Energy-related CO2 Emissions in 2050 (MMTCO2)

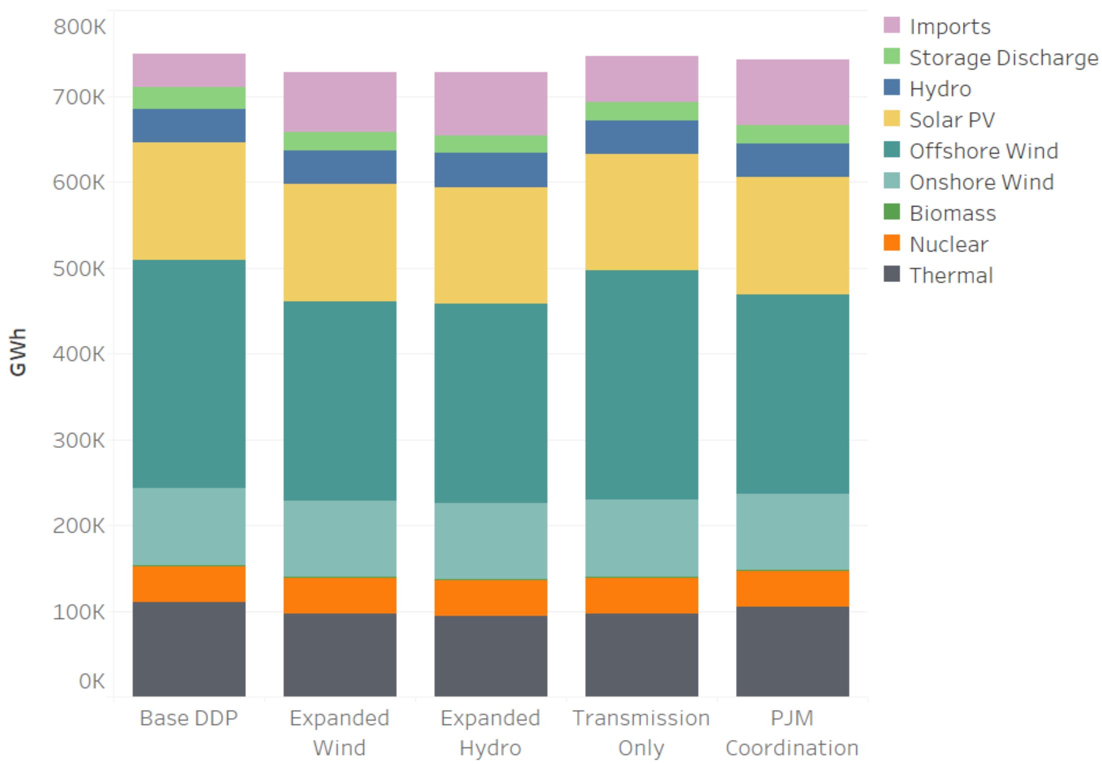


Notes: in million metric tons CO_2 ($MMTCO_2$). Grey band refers to 80 to 85 percent reduction below 1990 levels.

Electricity Sector

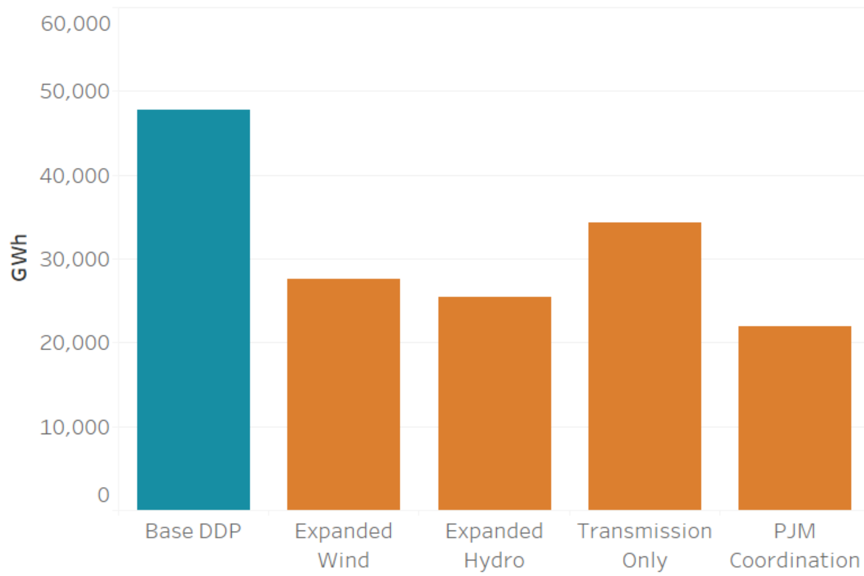
Figure 27 compares electricity generation in the increased coordination cases against the Base DDP Case. As the figure shows, total generation in the increased coordination cases is lower than the Base DDP Case despite the increase in imports due to lower curtailment. For example, generation in the Expanded Wind Case is approximately 20,000 GWh less, and the other scenarios with resource expansion in Québec (i.e., Expanded Hydro (e) and PJM Coordination (g) cases) show the largest decrease in overall generation, driven by less offshore wind and thermal generation.

Figure 27. Northeast Electricity Generation by Technology in 2050



The decrease in overall generation requirements mirrors the change in total curtailment, as shown in Figure 28. Scenarios where both transmission and generation resources are expanded translate into lower curtailment relative to transmission-only expansion, because the additional resources in Québec provide both resource diversity (i.e., tradeoff between offshore wind in the Atlantic and onshore wind in Québec) and system flexibility (i.e., dispatchable hydro resources), which allows for the Northeast to decrease the supply of inflexible generation.

Figure 28. Northeast Curtailment in 2050



The decrease in generation requirements and curtailment contributes towards lower installed capacity in the Northeast, as shown in Figure 29. Increased transmission and generation resources in the Expanded Wind, Expanded Hydro and PJM Coordination cases avoids the need to develop nearly 20 GW of resources within the Northeast. Approximately half of the avoided resources are offshore wind, while the remaining half are thermal resources which are no longer required, because the Northeast can rely on HQ resources across expanded interties during peak load hours.

Figure 29. Northeast Installed Capacity in 2050

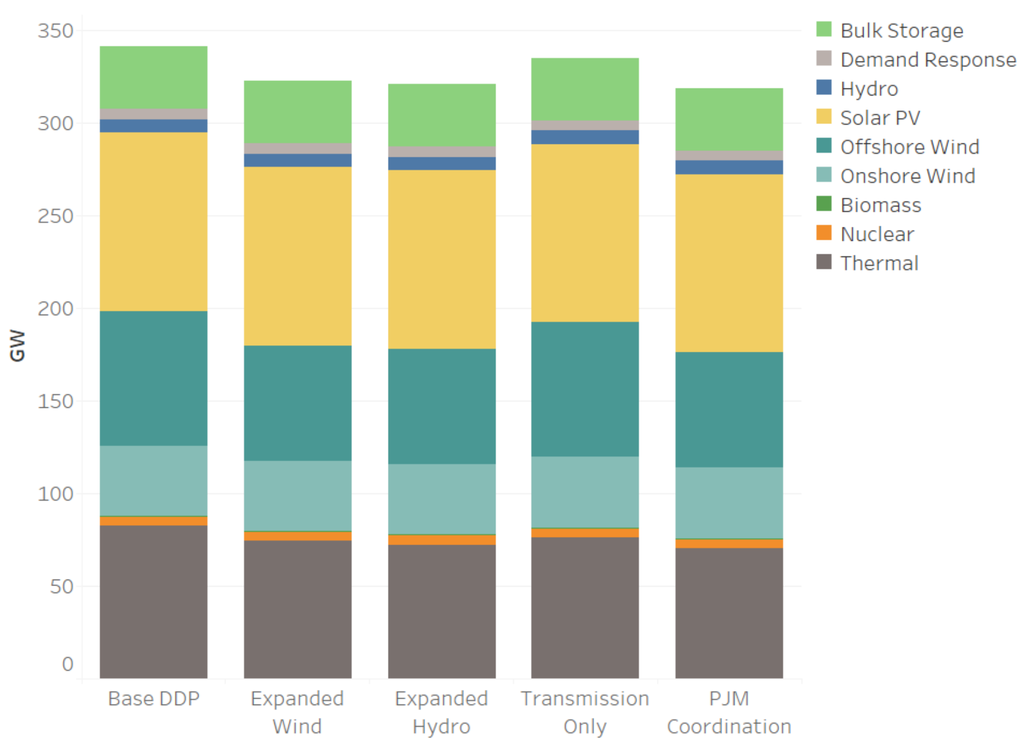


Figure 30 through Figure 32 illustrate the impacts of increased coordination through seasonal operating profiles for New England, New York and Québec in the Expanded Wind Case. Expanding transmission capacity between the two regions, as well as developing onshore wind in Québec and reducing offshore wind in the Northeast allows for: (a) higher HQ imports into the Northeast during the winter, which avoids high marginal-cost thermal generation; and (b) during other seasons, increased HQ imports in the morning and evening shoulder hours, as well as exports from the Northeast to HQ during the daytime, which both contribute towards reducing curtailment. This produces a more efficient electricity system with a reduced capacity building and curtailment of renewable generation (40 percent lower).

Figure 30. New England, Expanded Wind Case, 2050

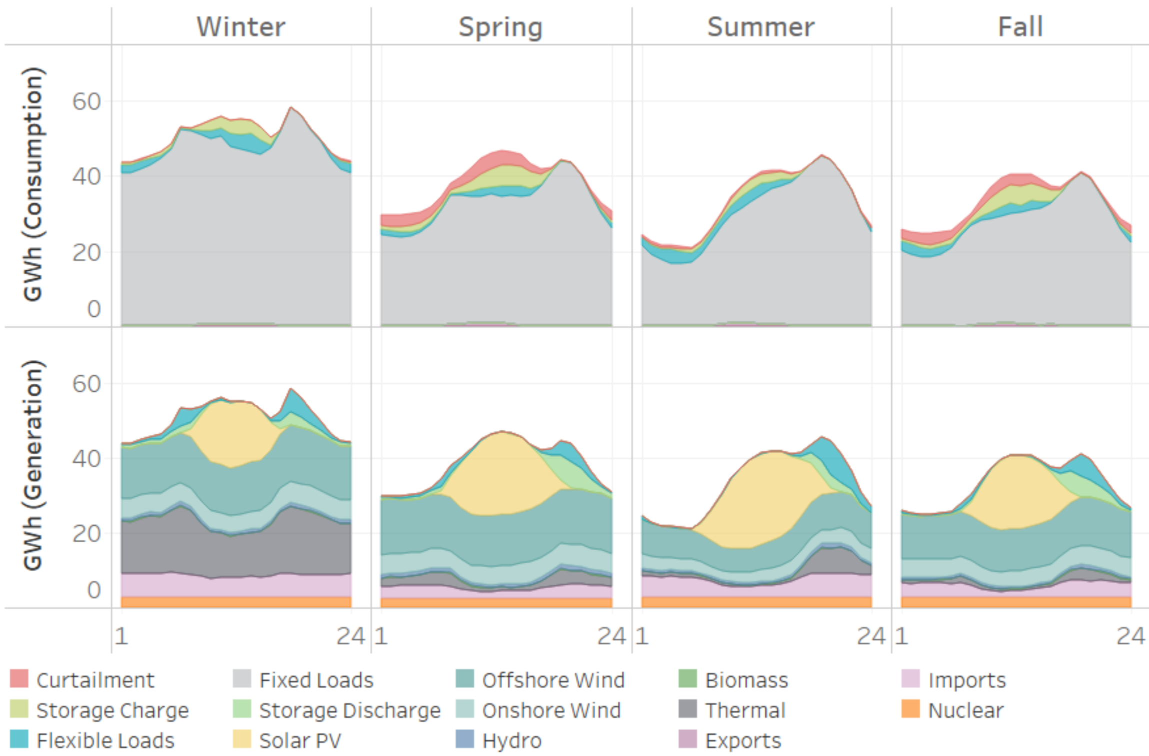


Figure 31. New York, Expanded Wind Case, 2050

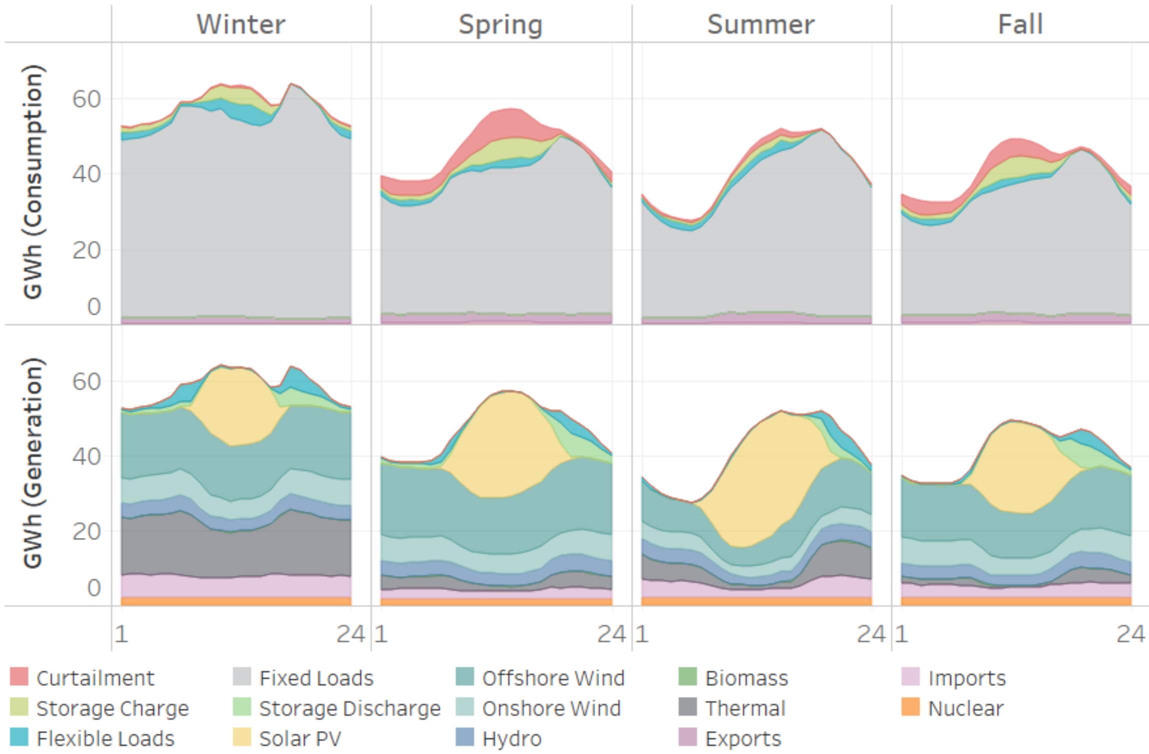


Figure 32. Québec, DDP with Expanded Wind-Hydro, 2050

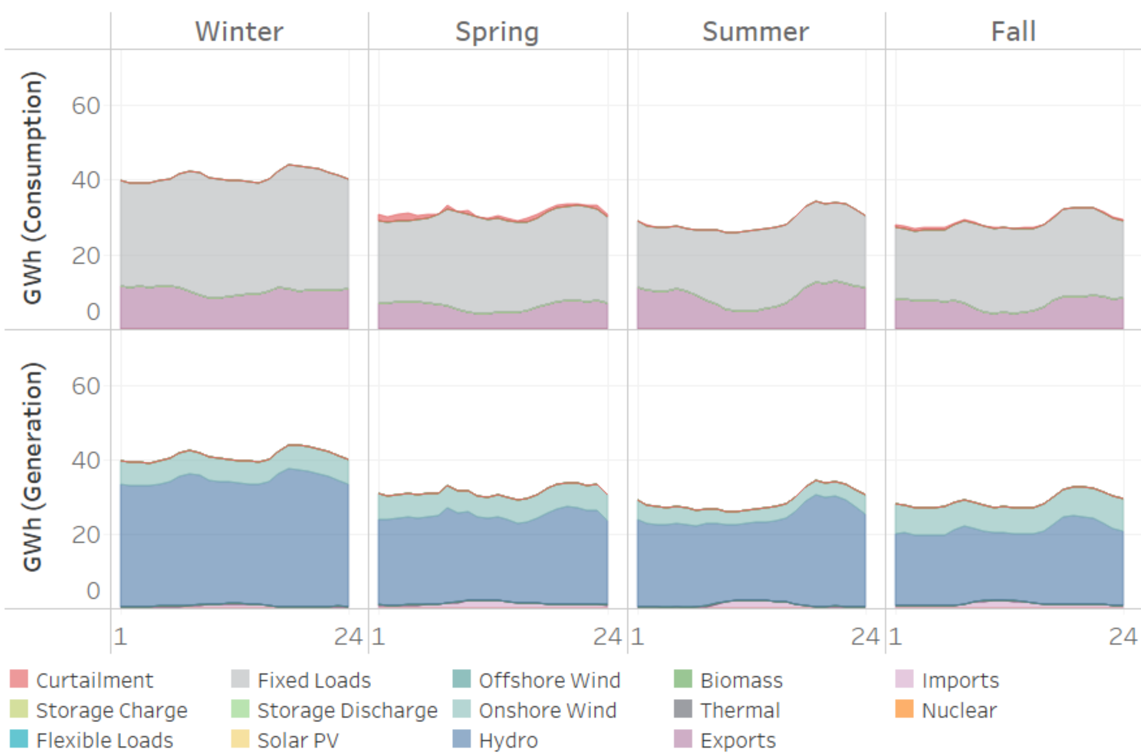
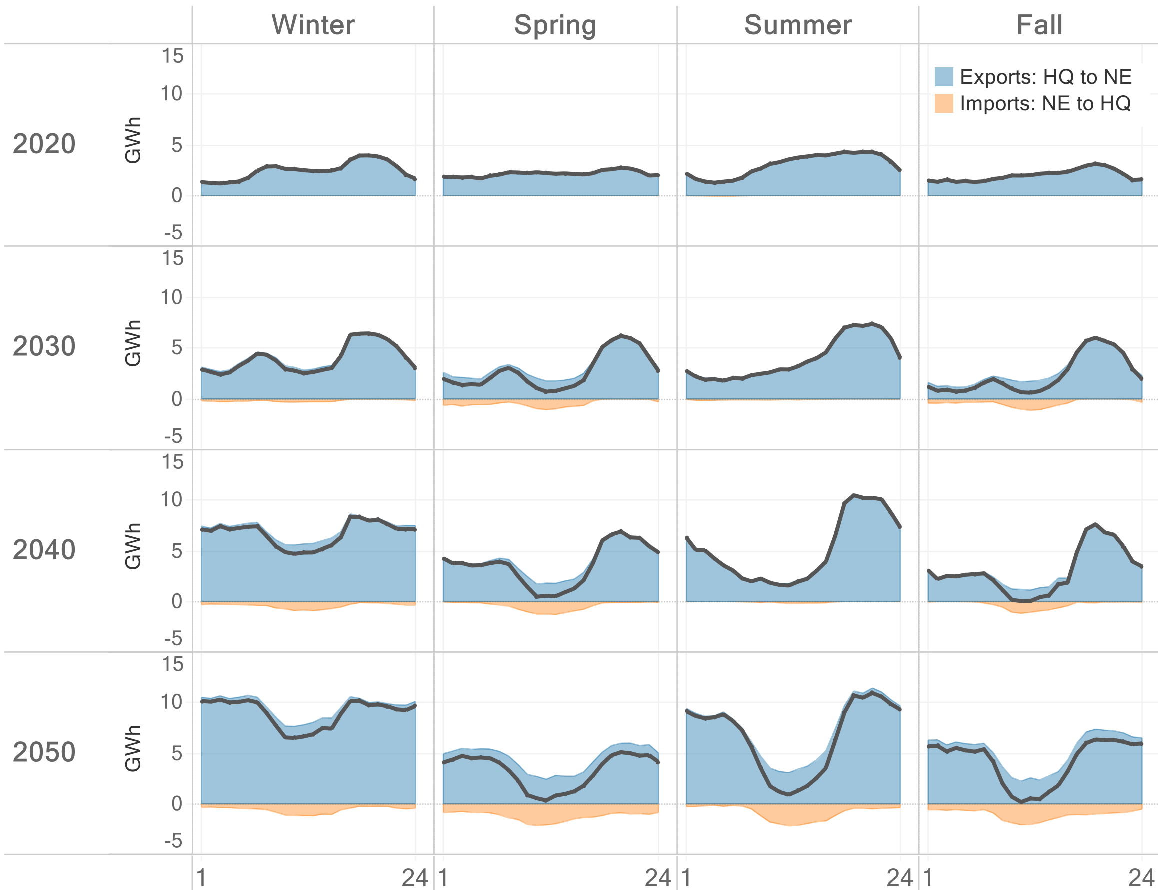


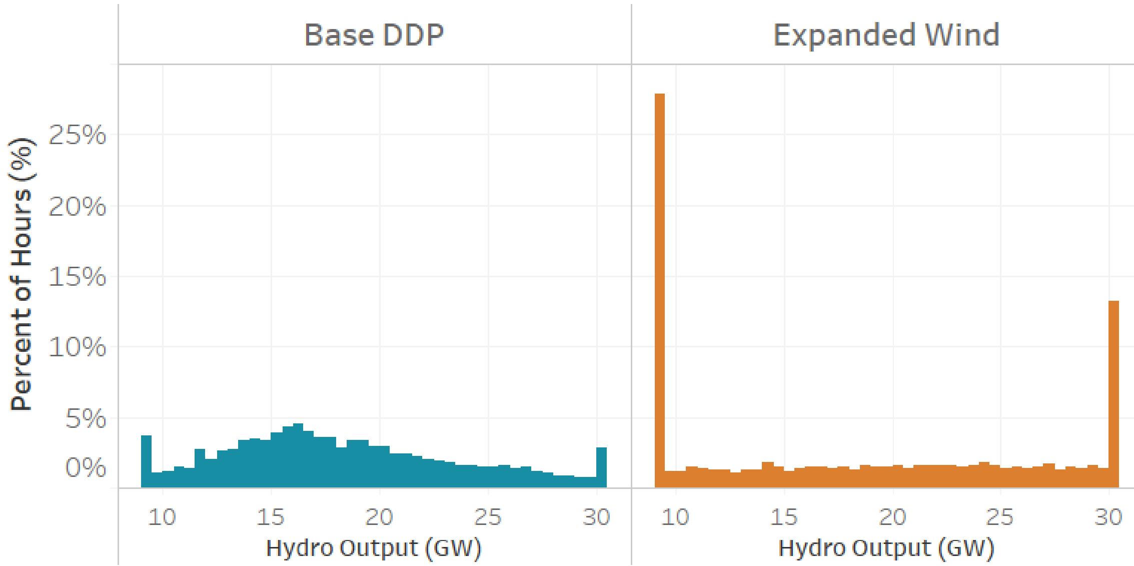
Figure 33 summarizes transmission flows between HQ and Northeast electricity systems and highlights the evolving nature of imports and exports over time as: (a) the Northeast's generation mix becomes increasingly inflexible due to higher wind and solar penetrations; and (b) the transfer capability between the two regions increases. From 2020 to 2050, overall exports from HQ to the Northeast increase, but the daily pattern becomes more dynamic, with exports ramping down during sunrise and ramping up during sunset. This pattern reflects the high levels of solar PV generation within the Northeast, and HQ electricity imports from the Northeast during daylight hours, particularly during the spring and summer.

Figure 33. Expanded Wind Case: HQ-Northeast Net Interchange



Achieving the transmission flows described above is due to both increasing transmission ties as well as changing the output of HQ's flexible hydro resources. Output (generation) from HQ's dispatchable hydro resources in 2050 is presented as histograms in Figure 34. In the Base DDP Case, hydro resources infrequently generate at their minimum or maximum operating capabilities, and instead generate at levels between these two points (approximately 95 percent of the time). In contrast, hydro generates at its minimum capability in almost 30 percent of hours in the Expanded Wind Case and at its maximum capability in nearly 15 percent of hours. Similar patterns are observed in the Expanded Hydro, PJM Coordination and Transmission Only cases, but not in the Reference or Base DDP cases, which suggests that expanded intertie capacity is necessary to realize the full flexibility of HQ's fleet to support balancing across the region.

Figure 34. Distribution of Output from HQ Dispatchable Hydro Fleet in 2050



Economic Costs and Benefits

One of the primary results of this study is the economic costs and benefits of increased coordination between HQ and the Northeast. The net benefits (cost savings) weigh: (1) increasing investment costs for electricity generation located in Québec and transmission costs to expand interties between the two regions; against (2) decreasing costs for renewable and balancing resources in the Northeast that are avoided due to increased coordination. The results in this section focus on net benefits for the Expanded Wind Case, which are estimated relative to the Base DDP Case, and we present summary results for all four increased coordination DDP cases. Cost and benefit results are presented for the region as a whole (i.e., New England, New York and Québec together).

Region-wide Costs

Increased coordination between Québec and the Northeast necessitates additional energy infrastructure beyond what is included in scenarios continuing present-day coordination (i.e., the Base DDP and Reference scenarios). Incremental energy system cost components include:

- **Incremental Transmission Costs** are the annualized fixed costs associated with expanding interties between HQ and the Northeast[9]
- **Incremental HQ Onshore Wind Resource Costs** are the annualized fixed costs of onshore wind power plants developed in Québec with the purpose of exporting the energy to the Northeast
- **Incremental HQ Hydro Resource Costs** are the annualized fixed costs of developing new hydro impoundments in Québec with the purpose of exporting the energy to the Northeast

[9] Transmission costs for incremental ties between HQ and Northeast are based on publicly-available data for the Champlain Hudson Power Express: $2.2 billion for 1000 MW, or $2,200 per kW. We apply an annualized cost of $225/kW-yr. using a capital recovery factor of 10.23% (40 years; 10% discount rate).

Table 9 summarizes the components of region-wide costs for the Expanded Wind Case where total gross costs are $4.08 billion per year. Expanding transmission ties by 9 GW (from 4,115 to 13,205 MW) by 2050 costs approximately $2.05 billion per year and developing more than 11 GW of onshore wind power plants in Québec incurs a cost of $2.03 billion per year. Since there are no new hydro impoundments in this scenario, then incremental HQ hydro resource costs are zero.

Table 9. Summary of Region-Wide Gross Costs in 2050 for Expanded Wind Case

Component	Costs ($mil/yr.)
Incremental Transmission Costs	$2,045
Incremental HQ Onshore Wind Resource Costs	$2,033
Incremental HQ Hydro Resource Costs	$0
Total Costs	**$4,079**

Region-wide Benefits

The development of expanded transmission interties and renewable resources in Québec allows the Northeast to avoid costs associated with generating resources providing energy, capacity and balancing services *while achieving the same level of emissions reductions*. The economic benefits ("avoided costs") that are quantified include:

- **Avoided Offshore Wind Resource Costs** are the annualized fixed costs of offshore wind power plants in the Northeast that are avoided due to increased coordination. Offshore wind is assumed to be the marginal renewable resource technology in the Northeast due to its large resource potential relative to other technologies.
- **Avoided Thermal Capital Costs** are the annualized fixed costs of gas-fired combined cycle and combustion turbines in the Northeast that are avoided due to the capacity benefit of expanding interties.
- **Avoided Thermal Production Costs** are the variable costs from thermal generation in the Northeast that are avoided due to increased imports from HQ. This includes fuel (fossil natural gas and renewable natural gas) and variable O&M costs.

Table 10 summarizes the components of region-wide benefits for the Expanded Wind Case where total gross benefits are $8.3 billion per year in 2050. Expanding intertie capacity and increasing the flow of clean electricity from HQ allows the Northeast to avoid developing 10.4 GW of offshore wind resources and save $5.7 billion per year. It is important to note that more than 60 GW of offshore wind is still developed in the Atlantic in the Expanded Wind Case, and only the most expensive portion (further along the supply curve) is not developed. Increased coordination also facilitates fewer thermal resources while maintaining the same level of resource adequacy, which saves $0.9 billion per year. The thermal resources that are still in service generate less frequently, which saves fuel (production costs) and produces a benefit of $1.6 billion per year. The production cost savings in 2050 are relatively high because: (1) assumed natural gas prices are higher compared to today; and (2) half of the fuel input is from renewable natural gas, which is more expensive to produce than natural gas.

Table 10. Summary of Region-Wide Gross Benefits in 2050 for Expanded Wind Case

Component	Benefits ($mil/yr.)
Avoided Offshore Wind Resource Costs	$5,718
Avoided Thermal Capital Costs	$914
Avoided Thermal Production Costs	$1,655
Total Costs	**$8,287**

Region-wide Net Benefits

Figure 35 summarizes the estimated benefits and costs of increased coordination in 2050 for the Expanded Wind Case. The figure shows gross benefits (in blue) from avoided offshore wind (OSW) and thermal resources of approximately $8.3 billion per year. These benefits are offset by incremental transmission and generation costs (in red) of approximately $4.1 billion per year. Net benefits (in green) are $4.2 billion per year, and this finding shows that increased coordination with HQ can help New York and New England achieve their deep decarbonization goals more cost-effectively.

Figure 35. Annual Net Benefits in 2050: Expanded Wind Case

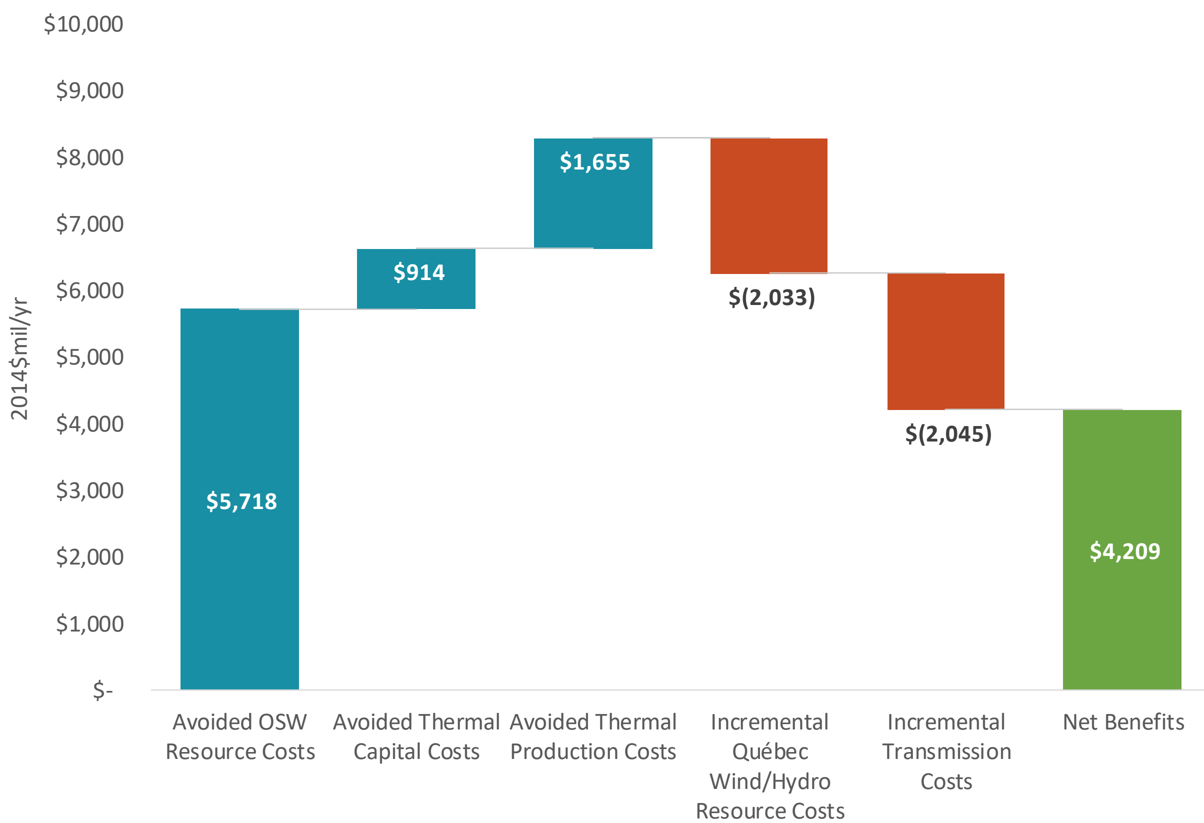


Table 11 summarizes the high-level case assumptions and net benefit results for all of the increased coordination scenarios. As shown in the table, developing new hydro in place of onshore wind in Québec ("Expanded Hydro") results in slightly higher net benefits ($4.38 billion per year compared to $4.21 billion per year), and the additional $170 million per year in benefits is driven by the flexibility of hydro, which can further reduce energy and capacity of thermal resources in the Northeast. However, only expanding transmission ties without new clean electricity supply in Québec results in a relatively small net benefit of $0.13 billion per year. Benefits are depressed in this case since exports are limited to *existing* HQ resources and the Northeast must develop the same level of offshore wind resources as in the Base DDP Case. If the Northeast simultaneously pursues enhanced coordination with PJM, then net benefits are lower relative to the Expanded Wind Case ($3.1 billion per year). However, if production cost savings realized in the PJM region are included with the benefits to New England, New York and Québec, then net benefits are nearly $5.0 billion per year. These finding highlights that enhanced coordination with neighboring systems, whether it's HQ or PJM, is highly beneficial in a deeply decarbonized energy system.

Table 11. 2050 Net Benefits for Deep Decarbonization with Increased Coordination Cases

Scenario	Expanded HQ/Northeast Ties	Expanded NYISO/PJM Ties	New HQ Hydro for Export	New Québec Wind for Export	Net Benefits ($mil/yr.)
Expanded Wind	+9,090 MW	n/a	n/a	+30 TWh	**$4,209**
Expanded Hydro	+9,090 MW	n/a	+30 TWh	n/a	**$4,380**
Transmission Only	+9,090 MW	n/a	n/a	n/a	**$132**
PJM Coordination	+9,090 MW	+3,000 MW	+30 TWh	n/a	**$3,099** ***$4,993**

Notes:
Net benefits relative to Primary DDP Case.
*Inclusive of production cost savings realized in PJM.

Table 12 summarizes a cost sensitivity analysis for the Expanded Wind Case where Northeast offshore wind and HQ onshore wind costs vary as a percentage of their base projected value (50, 100 and 150 percent). If offshore wind is half of its projected cost and HQ wind is 50 percent higher, net benefits are reduced to approximately $300 million per year. The opposite sensitivity (50% lower HQ wind cost, 50% higher offshore wind cost) increases net benefits to $8.4 billion per year. As shown in Table 13, sensitivity results are similar for the Expanded Hydro Case where offshore wind and HQ incremental hydro costs are varied.

Table 12. Cost Sensitivity Table: Expanded Wind Case ($billion/yr.)

		NE Offshore Wind Cost		
		0.5x	**1.0x**	**1.5x**
HQ Wind Cost	**0.5x**	2.4	5.2	8.1
	1.0x	1.3	4.2	7.1
	1.5x	0.3	3.2	6.1

Table 13. Cost Sensitivity Table: Expanded Hydro Case ($billion/yr.)

		NE Offshore Wind Cost		
		0.5x	**1.0x**	**1.5x**
HQ Hydro Cost	**0.5x**	2.7	5.6	8.4
	1.0x	1.5	4.4	7.2
	1.5x	0.3	3.2	6.0

Reference Case with Increased Coordination

The sections above only present the impacts of increased coordination in the context of deep decarbonization in the Northeast. However, transmission capacity and resource development in Québec for export could be pursued under current policy. We estimate the impacts of increased coordination under BAU policy through: (a) 30 TWh of new hydro resources developed in Québec for export to the U.S.; and (b) transmission capacity increases by 9 GW. This Reference with Expanded Hydro Case contains the same level of generation and transmission expansion as modeled in the Expanded Hydro Case, which may be oversized for the carbon reductions considered under current policy.

Figure 36 presents the impact on hourly electricity system operations in New England in 2050 with current coordination (Reference Case) and increased coordination (Reference with Expanded Hydro Case). Higher imports from HQ significantly reduce thermal generation, particularly during the summer where air conditioning loads drive peak demand. In addition to reducing energy from gas-fired resources, higher imports reduce the capacity of these resources by more than 5 GW in 2050. Electricity sector emissions across the Northeast decrease by 11.6 $MMTCO_2$ in 2050, but these emissions reductions fall substantially short of the study's economy-wide GHG targets.

Figure 36. New England Seasonal Dispatch in 2050

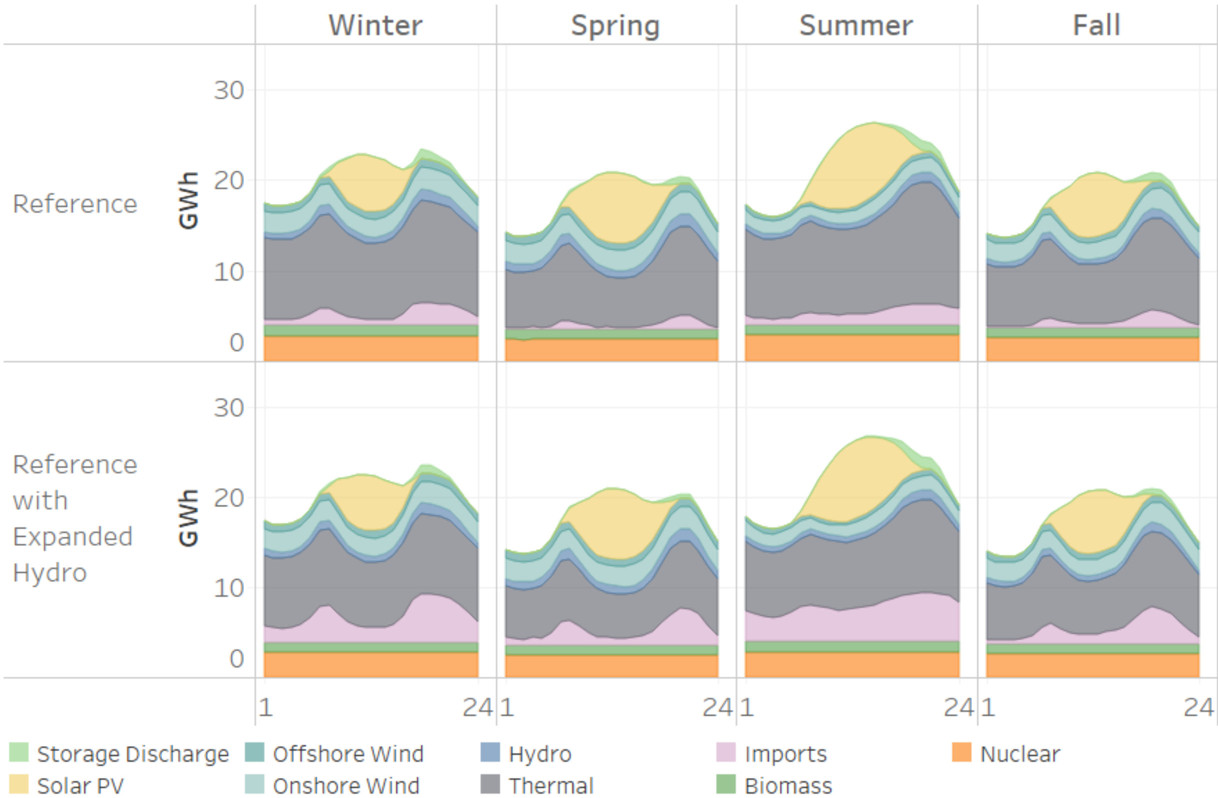


Table 14 summarizes the economic costs and benefits for the Reference with Expanded Hydro Case. In order to value the incremental avoided emissions, net benefits are presented across a range of carbon prices, including \$0/tCO_2, \$20/tCO_2 and \$100/tCO_2. Under our base assumptions (carbon price of zero), gross benefits from avoiding thermal capital and production costs are \$2.0 billion per year. These are offset by \$4.4 billion per year in incremental hydro and transmission costs, resulting in a net cost of \$2.4 billion per year. If incremental CO_2 emissions reductions are valued between \$20 and \$100/tCO_2, then net costs are reduced to \$1.3 to \$2.2 billion per year. In order to reduce net costs to zero (i.e., breakeven), then a CO_2 price of approximately \$200/tCO_2 would be required. Lower levels of transmission and resource expansion may show net benefits under current policy, since the value of carbon-free imports diminishes as the efficiency (heat rate) of the marginal fossil resource improves (i.e., the merit-order effect). The economic results shown here and in prior sections show that the high levels of increased coordination considered in this study (i.e., 9 GW of expanded transmission capacity) provide the most value when the Northeast pursues aggressive carbon reductions that require an electricity system with very high penetrations of inflexible, carbon-free generation.

Table 14. 2050 Net Benefits for Reference with Expanded Hydro Case

	Gross Benefits ($mil/yr.)	**Gross Costs** ($mil/yr.)	**Net Benefit (Cost)** ($mil/yr.)
Base Assumptions ($0/t$CO_2$)	$2,024	-$4,434	-$2,410
Incl. Value of CO_2 Reductions			
Low ($20/t$CO_2$)	$2,256	-$4,434	-$2,179
High ($100/t$CO_2$)	$3,182	-$4,434	-$1,253

Notes: net benefits are relative to Reference Case.

Conclusions

What does deep decarbonization require?

The results show that the deeply decarbonized energy system can provide the same energy services to the economy and daily life as a business-as-usual case, and does not need to be accomplished overnight. It can be achieved through the ongoing deployment of efficient, low-carbon technologies that are already commercial, combined with the steady retirement of low efficiency, high-carbon technologies. While this can be done deliberately, the changes required are not incremental improvements over the *status quo*. They are unprecedented and transformational.

The extent of the transformation is shown by three metrics that represent the three principal measures needed to reach that 80 x 50 target (Table 2). First, greatly increased efficiency of energy end use, as indicated by a 40% decrease in energy use per capita between today and mid-century while maintaining all existing energy services. Second, reaching a very low carbon intensity of electricity, 29 grams of CO_2 per kilowatt-hour, an 87% decrease from current levels. Third, switching of end uses from direct combustion of fossil fuels to electricity, represented by a tripling of the electricity share, to 55% of final energy consumption from 18% today.

Table 2. Metrics for "three pillars" of deep decarbonization, comparing current values to DDP base case

Pillar	Unit	2015 value	2050 DDP	% change
Energy efficiency	Annual per capita energy use (MMBtu/person)	168	101	-40%
Carbon intensity of electricity	Carbon emissions per unit of electricity (kg CO_2/MWh)	228	29	-87%
Electrification of end uses	Electricity share of end use energy consumption (%)	18%	55%	+210%

These changes are sometimes called the *three pillars* of deep decarbonization, because the outcome rests on having all three at the same time. When they occur together, there is a multiplicative effect on emissions reductions, for example in the case of electric vehicles, in which electric drive trains are more energy efficient than those with internal combustion engines, and displace fossil fuels with near-zero carbon electricity. The same logic holds for the replacement of natural gas and oil furnaces and water heaters with efficient electric heat pumps. The most formidable policy challenge on the demand side of the energy system will be attaining the rapid electrification of end uses.

What does deep decarbonization mean for the electricity sector?

For the electricity sector, there are two simultaneous requirements. First, there must be a major increase of electric load, roughly doubling today's by mid-century. In the DDP case for the Northeast, load is 86% higher than the reference case, due primarily to electrification of virtually all light-duty vehicles, plus meeting two-thirds of building space and water heating demand. Second, there must be a vast increase in low carbon generation. Given current policy preferences in the Northeast, the DDP case achieves this with renewable energy rather than nuclear or fossil generation with carbon capture and storage. In 2050, two-thirds of all generation comes from solar PV and wind power.

These requirements pose three serious challenges for electricity provision in a Northeast 80 x 50 scenario. First, electricity systems with very high shares of wind and solar generation can have imbalances between energy supply and demand that are of larger magnitude than can be addressed with natural gas generation constrained by carbon emission limits. These imbalances are also on longer time scales (weekly to seasonal) than can be addressed by hourly-to-diurnal storage technologies such as batteries. Second, an unprecedented buildout of renewable resources is required to decarbonize electricity generation. This includes a high proportion of offshore wind in increasingly remote locations to supplement onshore wind and solar PV, as the best sites for these are utilized or high daytime curtailment makes it difficult to reach higher penetrations. Third, the cost of generation increases steeply for remote offshore wind, as transmission costs exceed generation costs, and the cost of balancing resources also increase steeply when scarce biomass is used as a low-carbon fuel in thermal generation.

What are the potential benefits of expanded Northeast-HQ coordination?

This question is posed as a response to the electricity sector challenges described above. HQ already plays an important role in Northeast electricity, exporting 22 terawatt-hours per year of carbon-free electricity over more than 4000 megawatts of interconnection. This transmission capacity allows south to north exports at certain times during the year to go with the predominantly north to south flow, keeping transmission utilization rates high. Several factors make expanded coordination an option worth investigating. First, within Québec there is significant new resource potential at relatively low cost within close geographic proximity to the Northeast. Second, the HQ system, with its large reservoir capacity, has the latent flexibility to provide balancing on a seasonal scale.

To analyze potential costs and benefits, the DDP base case was compared to four different scenarios of expanded Northeast-HQ coordination that also reach the 80 x 50 target. These scenarios vary along different axes of what "increased coordination" could mean: (i) expanded exports and transmission capacity between Canada and the Northeast, versus no expansion; (ii) incremental hydro resources versus incremental wind resources, in both cases developed within Québec for export; and (iii) including the PJM balancing area as a U.S. participant in expanded coordination, versus including the Northeast only.

These scenarios were compared to the DDP base case in terms of net costs and benefits, investment requirements, transmission requirements, generation mix, and operational changes.

The cases with expanded hydro and expanded wind resources in Québec both show a net benefit of more than $4.2 billion (current US$) per year. The case with expanded hydro plus PJM involvement shows a net benefit of almost $5 billion per year, but $1.9 billion of that accrues to PJM rather than the Northeast as a consequence of avoided renewable curtailment. The case with expanded transmission capacity has a relatively small net benefit of $130 million per year.

The costs and benefits of coordination are illustrated by the expanded wind case. The benefits come from replacement of the costliest offshore wind resources that would otherwise be required with less costly Canadian onshore wind, and from utilization of the HQ system for balancing, allowing south-north flows of excess solar generation that would otherwise be curtailed in the Northeast, and avoiding the high cost thermal biomass balancing resource. The gross benefits of $8.3 billion per year from these savings are partially offset by increased resource costs (in Québec) and transmission costs (between Québec and the Northeast) of $4.1 billion per year, resulting in a net benefit of $4.2 billion per year.

Net benefits of more than $4.2 billion per year represent a reduction of more than 6.5% of the annual incremental cost of electricity generation in the Northeast in the DDP base case. A sensitivity analysis with offshore wind at 50% of its projected cost in the base case, and HQ wind at 50% higher cost, reduces net benefits to $300 million per year, while the opposite sensitivity (50% lower HQ wind cost, 50% higher offshore wind cost) increases them to $8.4 billion per year. For offshore wind and HQ incremental hydro, the sensitivity results are similar.

What are the operational challenges of expanded Northeast-HQ coordination?

The scenario results indicate several potential operational challenges for the HQ system. The economic benefits of expanded coordination derive primarily from operating HQ's system as a regional battery with extensive south-north as well as north-south flows. This takes greater advantage of the flexibility of the HQ reservoir system, but is a departure from the longstanding model of electricity exports in fixed schedules, in business, operational, and hydrological terms. These challenges derive partly from changes in the seasonal timing of peak load in the Northeast under deep decarbonization due to the electrification of heating loads, so that peak loads occur in January, coincident rather than complementary with the HQ system peak.

In addition to a new seasonal operational context, the daily context also changes dramatically. The nature of imports and exports evolves over time as the Northeast's generation mix becomes increasingly inflexible due to higher wind and solar penetrations, and the transfer capability between the two regions increases. From 2020 to 2050, overall exports from HQ to the Northeast increase, but the daily pattern becomes more dynamic, with exports ramping down during sunrise and ramping up during sunset. This pattern reflects the high levels of solar PV generation in the Northeast, with HQ importing electricity from the Northeast during daylight hours, particularly during the spring and summer. A consequence of increased diurnal swings in imports and exports is potentially much faster ramping (the rate of increased or decreased generation in MW per hour) of the HQ system than at present.

Is a Phase 2 study warranted, and if so what should be included in it?

The scale of potential benefits shown by this analysis – greater than 6.5% of the incremental generation cost of deep decarbonization – indicates that a deeper investigation is warranted. The key topics and analytical needs of a prospective Phase 2 study are suggested by the findings, and the limitations, of this initial analysis. The main issues pertain to scenario design, cost, operations, and environment.

(1) The DDP base case used in this study is not the only or best DDP for the Northeast. It was designed to illustrate general features of DDPs that have proven to be robust in similar studies, such as the "three pillars," and provide boundary conditions for the expanded coordination analysis. It reflects current policy preferences in the region, but not necessarily the best possible resource mix. A Phase 2 study should develop a wider set of technology pathways and ranges of assumptions about cost and performance, with inputs from regional stakeholders and experts.

(2) The expanded coordination scenarios developed for this study are not optimized for cost. The resource builds, export levels, and transmission additions were selected to illustrate a range of options for expansion of Northeast-HQ coordination, but were not meant to represent the best possible economic outcome. Potential benefits could be larger than these scenarios show. In addition, stability and contingency assessments are needed to understand the implications of tripling interties between the Northeast and HQ. A follow-on study should feature optimal capacity expansion, and greater transmission representation in production cost and power-flow modeling, accompanied by extensive sensitivity and uncertainty analysis.

(3) The implications of the operational challenges for the hydro system described above – major changes in the seasonal and diurnal timing and ramp rates for the filling and emptying of reservoirs - will require extensive hydrological and hydro system operations modeling. Potential impacts of climate change on hydrologic flows should also be factored in.

(4) The siting and development of new hydro or wind resources and transmission upgrades will require environmental assessment on both sides of the border. Prior to assessment of actual proposed projects, an initial scoping of potential environmental limitations can help provide constraints and cost estimates needed for Phase 2 modeling and scenario design.

A Phase 2 study would aim to inform the discussions among key regional stakeholders that would be required before any concrete steps toward expanded coordination are made. A central issue is how system-wide benefits, costs, and risk would be allocated among the parties, and what changes in current wholesale market and RTO rules and procedures would be necessary to allow greater cross-border integration of planning, procurement, and operations.

It should be acknowledged that the vision of expanded coordination in the present study is narrower than what could be imagined in an urgent mobilization to rapidly reduce greenhouse gas emissions. A larger vision could include fully integrated regional planning and resource markets, and possibly synchronization and full AC interconnection. However, given the limits of historical levels of coordination – including among the states and RTOs of the Northeast, as well as across the national border – the objective of a limited expansion makes sense as an initial

Phase 2 focus. A key to success will be the participation of regional stakeholders and experts from government, utilities, RTOs, labor, and environmental organizations, both in technical discussions and in creating a shared vision of how to achieve a low carbon future.

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