The Staggering Costs of New England's Green Energy Policies

Isaac Orr, Mitch Rolling, and Trevor Lewis
Always On Energy Research

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September 2024 Authors' Note: This report is a continuation of the work performed by authors at Always On Energy Research (AOER) modeling the cost of energy portfolios in states throughout the country. Portions of this report have been repurposed and modified to reflect the result of state Decarbonization Plans in the Independent System Operator of New England.

Executive Summary

The six New England states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont) are anticipating seismic changes to their electricity generating system in the coming decades. All but New Hampshire have committed to reducing their carbon dioxide emissions by at least 80% by 2050 (Net Zero policies), prompting ongoing changes in the grid's resource mix and the increased electrification of the heating and transportation sectors.[1,2]

If these Decarbonization Plans are realized, New England will go from generating about 6% of its electricity from renewable energy (solar, wind and batteries) in 2023 to generating 71% in 2050.

Our analysis anticipates that New England's demand for electricity is expected to increase 106% by 2050, driven by the home heating and transportation sectors. The growth of electricity demand in the winter will be particularly pronounced, causing New England's peak electricity usage to change from a summer peaking system in 2023 to the winter by 2035.

ISO-NE (New England's regional electricity transmission organization, which schedules electricity supply so that it meets demand) estimates that 97 GW of new utility-grade renewables will be needed to "decarbonize" the grid by 2050, an exponential increase over the currently installed 4 GW. However, to meet forecasted demand for electricity 24/7/365, we calculate that 225 GW of new renewables would be needed if the wind and solar energy output for 2050 follows the patterns of 2023 output. The most economically efficient mix of renewable buildout would require over 6,600 offshore wind turbines, over 5,600 onshore wind turbines, and over 129 million solar panels. The solar panels alone would cover over 200 square miles.[3]

Building out "only" 97 GW of renewables puts the grid at risk for extraordinarily long blackouts, of around 18 hours long.

But choosing the more reliable 225 GW option is likely to be cost prohibitive. Our analysis found that this resource mix would cost New England ratepayers $815 billion through 2050, excluding the impact of federal subsidies. This is approximately a little more than half of the region's entire economic output in a single year.[4] Ratepayers can expect a corresponding doubling (above inflation) increase in the price of electricity by 2050 versus 2023 prices. This means the average residential ratepayer can expect to see their electricity prices increase nearly $99 each year. Meanwhile, the average commercial and industrial ratepayers can expect price increases of $489 and $5,280, respectively.

Despite this massive investment, even 225 GW of new renewables will likely not be enough to fully meet electricity demand by 2050, especially in light of 2023 wind and solar output patterns. (During some weekly stretches in 2019, solar and wind power was lower than in 2023.) In which case, our resource adequacy analysis shows that the 225 GW will prove inadequate for meeting the hourly electricity demand data, based on ISO-NE projections for 2050 demand. A capacity shortfall for the region is likely to result in rolling blackouts during the winter months. This is not to suggest that New England will be spared blackouts until 2050. Shorter blackouts may occur in the meantime.

The return benefits for Net Zero are miniscule. Even the 'Social Cost of Carbon' figure taken from the Biden Administration shows that the anticipated global benefits for these Net Zero policies fall well short of spiraling costs to New England.

To make matters worse, many states and utility companies are considering new Environmental, Social, and Governance (ESG) proposals. Anticipating this, the region's companies are exploring the introduction of gaseous hydrogen into pipelines, which could increase the cost of natural gas heating by up to $1,588 a year for every New England ratepayer by 2050. For households already dealing with electricity price increases, this will prove a significant hardship.

ESG policies are also reducing the potential investment returns for public pension funds, which are struggling to reach full funding. The Paris Climate Accords, closely associated with ESG policies, are being prioritized over the retirements of thousands of New England state employees and teachers. Maine, Vermont and Rhode Island already have some form of ESG pension legislation on their books, forcing pension investors to bypass the most promising pension investments and divest from others. Nearly a dozen bills have been introduced in Massachusetts and Connecticut with a similar goal in mind.

Net Zero and ESG policies will end up restricting economic growth by refusing businesses and households the most efficient means of meeting their energy needs. Resources that could have gone toward innovation and production will be diverted toward meeting mandates that have few tangible benefits. Worst of all, rolling blackouts will leave New England's most vulnerable populations dependent on a finicky electric grid to survive. Respiratory problems, kidney disease and deaths tend to spike during blackouts, as the hospital instruments needed to keep sickly people alive power down.[5]

These policies, when fully explored, cannot be rationalized. If New England's net-zero policies are fully enacted, the region is likely to see a mass exodus of businesses and workers to other regions of the United States. There is still time to alter course, to demand that the skyrocketing costs for such draconian policies be counted alongside their (meager) benefits. By doing so, we can return New England to the days when it successfully balanced environmental conservation and economic productivity.

Introduction

The *Economic Planning for the Clean Energy Transition* report released by ISO-New England (ISO-NE) in August of 2024 estimated a "vast renewable build-out" of 97 GW of new onshore wind, offshore wind, solar and battery storage to meet the 2050 state decarbonization goals. But *Economic Planning* only sought to estimate the amount of capacity needed to meet a target of reducing 1 million tons of carbon from fossil resources.

It did not attempt to answer the question of whether this new resource mix would be adequate for meeting the electricity needs of New England residents 24/7/365, in terms of cost and reliability. We believe this is the far more important question, given that New England is responsible for less than 0.4% of global emissions (related to heating, transportation *and* electricity).[6] Any attempts to affect the global climate through changes in the types of energy used to generate electricity in New England is difficult to justify

Driven largely by statewide commitments, the grid continues its shift toward non-dispatchable generation resources like offshore wind, onshore wind and solar photovoltaic (PV) systems.[7] Over the next few decades, these renewable resources are expected to substantially displace natural gas-fired generation as the region's primary resource type.

At the same time, increased electrification is expected to significantly increase overall consumer demand for electricity and drive changes in usage patterns that include seasonal and daily shifts in peak demand.[8] ISO-NE projects that increased electrification will shift the region from a summer peaking system to a winter peaking system with significantly larger peak demands than currently observed.

Meeting the challenges of providing reliable, affordable energy without generating greenhouse gas emissions will be made more difficult by the anti-nuclear policies in five of the six New England states. Each of these states, except for New Hampshire, has prohibitions or impediments to the construction of new nuclear power plants.[9,10]

As a result, state mandates to reduce carbon dioxide emissions will rely primarily on solar, offshore wind, onshore wind, battery storage and imports from neighboring regions. This resource mix will impose significant costs on New England families and businesses.

Policy Recommendations

1. **Reconsider emission-reductions goals** in the context of affordability and reliability of electricity. Legislators should prioritize affordability and reliability before emissions reductions goals. If emissions reduction goals cannot be reduced without compromising affordability and/or reliability of electricity, they should be abandoned.

2. **Lift state nuclear moratoriums.** Lifting moratoriums and impediments to building new nuclear power generators will be the most reliable and affordable way to decarbonize the New England grid. Connecticut, Maine, Massachusetts, Rhode Island and Vermont each have substantial barriers to nuclear energy.

3. **Purchase Power Agreement transparency.** Any state that mandates contracts for certain types of energy should clearly detail the cost of those contracts for the public. These reports should provide ratepayers with the expected increases (or decreases) in their monthly bills.

4. **Allow nuclear to compete with renewables**. Net Zero mandates treat renewable energy as more desirable than nuclear energy, despite both producing no carbon emissions. Allowing nuclear energy to be included toward meeting mandates will lower the costs for businesses and households.

5. **Require investment fee reporting.** Mandatory reporting of investment fees for state governments will allow for more transparency around the cost and benefit of generally higher-risk alternative investments like private equity and hedge funds, which are often used for ESG investments.

SECTION I

New England State Policies

Five of the six New England states have enacted a series of policies that require the grid to greatly reduce carbon dioxide emissions from the electricity sector, and many of these states have also enacted policies designed to electrify the transportation and home heating sectors. These electrification policies will result in large increases in the regional peak electricity demand.

Connecticut

In May 2022, Connecticut Gov. Ned Lamont signed a law establishing a 100 percent carbon-free by 2040 electricity mandate, codifying the standard that the governor established through executive order in 2019.[11] The legislation contained multiple benchmarks requiring emissions to be 45 percent lower than the levels emitted in 2001 by 2030, and 100 percent carbon free by 2040.[12]

To meet these mandates, in 2019, Connecticut authorized the procurement of 2,000 megawatts (MW) of offshore wind by 2030, with the Connecticut Department of Energy and Environmental Protection (DEEP) estimating the state will need 3,745 to 5,710 MW offshore wind by 2040.[13] While a joint offshore wind venture with Rhode Island and Massachusetts is currently up in the air, Gov. Lamont and lawmakers have continued to seek ways to make offshore wind work.[14] Connecticut has also established an energy storage mandate of 1,000 megawatts (MW) by the end of 2030.[15]

Several ESG bills have been introduced into the Connecticut legislature. In 2023, S.B. 1115 sought to leverage Connecticut's position as a national insurance provider and levy a 5% surcharge on policies insuring real estate and assets owned by fossil fuel companies.

While S.B. 1115 died in committee, the fossil-fuel surcharge was revived as a provision in S.B. 11, which implements Gov. Lamont's budget recommendations. Smuggling the surcharge into a larger omnibus bill assures other recent ESG bills will get their second wind.

Maine

In 2019, Maine Gov. Janet Mills signed legislation that increased Maine's Renewable Portfolio Standard (RPS), a law requiring a specified percentage of the electricity utilities sell comes from renewable resources, from 40 percent by 2030 to 80 percent by 2030 and 100 percent renewable by 2050.[16] However, in 2023, Gov. Mills announced her plan for accelerating Maine's trajectory to using 100 percent clean electricity from 2050 to 2040.[17] Maine is also seeking to reduce its economy-wide emissions by 45 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050.[18]

The Brattle Group, a consulting firm, is currently conducting modeling on behalf of the Governor's Energy Office in Maine to create a roadmap to enact these policies, including 80 percent renewable electricity by 2030, 100 percent "clean" electricity by 2040, adding 3,000 MW of offshore wind by 2040, adding 400 MW of storage by 2030, and installing heat pumps in 100,000 homes by 2025 and more than 175,000 homes by 2027.[19]

In 2021, Maine became the first state in New England to successfully require its state pensions to divest from fossil fuel companies. Similar legislation has been introduced in Vermont, Connecticut and Massachusetts' legislatures in recent years. As more states require their pension funds to liquidate and ban future investment in fossil fuel companies, energy companies will struggle to build new and maintain old natural gas pipelines. Without local funding for projects, the natural gas pipelines New England needs to achieve energy security may never be built.

Massachusetts

On March 26, 2021, then-Massachusetts Gov. Charlie Baker signed legislation called "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy" ("the Act"). The Act amends the state's Global Warming Solutions Act (GWSA) and requires Massachusetts to reduce economy-wide emissions by 50 percent compared to the 1990 baseline by 2030, 75 percent below the 1990 baseline by 2040, and achieving net-zero economy-wide greenhouse gas emissions by 2050.[20]

The Act also increased the state's offshore wind procurement target to 5,600 MW by June 30, 2027, and increased the required percentage of renewable electricity generated in Massachusetts to 39 percent by 2029, with the standard increasing by one percent per year thereafter.[21,22] Massachusetts also has a Clean Energy Standard (CES), requiring 80 percent of the electricity sold in the state to be carbon free by 2050.[23] Due to the heavy emphasis on the electrification of the transportation and home heating sectors, Massachusetts will likely need to exceed these goals in order to meet their economy-wide decarbonization targets.

The General Court of Massachusetts has also introduced legislation establishing ESG investing principles for state pension funds. Taken as a group, these bills would require fiduciaries to appraise companies' climate impact and require Massachusetts pension funds to divest all holdings in fossil fuel companies.

New Hampshire

New Hampshire's renewable energy mandates were established in 2007 and require the state's electricity providers, with the exception of municipal utilities, to acquire renewable energy certificates equal to 25.2 percent of retail electricity sold to end-user customers by 2025. The law contains subcategories requiring that 15.7 percent of this total must come from new renewable energy sources, such as wind or solar. Existing biomass, landfill gas and small hydroelectric resources make up the remaining percent of the Renewable Energy Mandate (REM) requirements.[24]

Although New Hampshire has no laws or targets for offshore wind, the New Hampshire Department of Energy released a report in September of 2023 to study the feasibility of offshore wind turbines in the Gulf of Maine.[25]

New Hampshire is the only state in New England that has not updated its Renewable Portfolio Standard (RPS) to align with the new net-zero push. New Hampshire has not passed any ESG policies. New Hampshire's legislature nearly passed a bill banning fiduciaries from investing state pension fund dollars in accordance with ESG metrics.[26] In 2021, under pressure from student activists, Dartmouth College pledged to divest the endowment from all fossil fuel companies.[27]

Rhode Island

In June of 2022, Rhode Island passed legislation requiring that 100 percent of Rhode Island's electricity be offset by renewable energy production in 2033. Under the legislation, the 2022 REM target of 19% would increase by an additional 4 percent in 2023, 5 percent in 2024, 6 percent in 2025, 7 percent in 2026 and 2027, 7.5 percent in 2028, 8 percent in 2029, 8.5 percent in 2030, 9 percent in 2031, and 9.5 percent in 2032 in 2033 to achieve the goal of 100 percent of Rhode Island's electricity demand being offset by renewable energy by 2033 and thereafter.[28]

On July 6, 2022, Gov. Dan McKee signed a bill into law mandating that Rhode Island's primary utility, Rhode Island Power, procure between 600 to 1,000 MW of additional offshore wind to Rhode Island's clean energy portfolio standard.[29]

This legislation was seen as pivotal to achieving the mandates set forth in the 2021 Act on Climate, which set mandatory, enforceable climate emissions reduction goals of 45 percent below 1990 levels by 2030, 80 percent below 1990 levels by 2050, and net-zero emissions by 2050.[30,31]

To further the state's commitment to climate goals, in June 2024, Rhode Island passed H.B. 7127 which established ESG metrics to guide fiduciaries charged with investing state pension funds. [32]

Vermont

In June of 2024, the Vermont legislature overrode Gov. Phil Scott's veto to enact more-stringent renewable energy mandates for the state.[33] These mandates would require Green Mountain Power, the state's largest electric utility, to obtain 100 percent of its electricity sales from renewable energy by 2030. All other providers would be required to meet this mandate by 2035.

The updated mandates effectively limit or prohibit new biomass plants from meeting the standards; prevent power from new Canadian hydroelectric dams in newly flooded areas from qualification; and establish in-state and in-region mandates for the location of new renewable resources.[34]

For Vermont, "new renewable energy" means renewable energy capable of delivery in New England and produced by a specific and identifiable plant coming into service on or after January 1, 2010, but excluding energy generated by a hydroelectric generation plant with a capacity of 200 MW or greater.

In June 2024, Vermont lawmakers followed Maine's example and passed a bill directing the state pension fund to divest from fossil fuels.[35] Vermont's Climate Change Cost Recovery Act seeks remuneration from oil and natural gas companies for their past emissions.[36]

Vehicle Electrification Policies

In addition to mandates for renewable or carbon free electricity, Massachusetts, Rhode Island and Vermont have adopted California's Advanced Clean Cars II regulations that ban the sale of new internal combustion vehicles by 2035.[37]

Connecticut and Maine have not adopted these regulations due to overwhelming opposition by the public. Instead, lawmakers in Connecticut are considering legislation that would create a "Zero-Emissions Vehicle Roadmap," and Maine has established a goal of putting 41,000 light-duty electric vehicles (EVs) on the road by 2025 and 219,000 EVs, constituting 18 percent of the total vehicle fleet, on the road by 2030.[38,39,40]

Meanwhile, New Hampshire currently has no regulations requiring the sale of electric vehicles in the state.[41]

Are the New England Decarbonization Plans Realistic?

These state Decarbonization Plans will require a massive buildout of new power plant capacity, costly transmission, electric vehicle infrastructure and the widespread deployment of heat pumps and other electric heating equipment on an aggressive timeline that may not even be possible.

Our analysis shows that these plans would require New England states to operate 66 gigawatts (GW) of offshore wind capacity, 19.2 GW of onshore wind, 68.4 GW of solar capacity, and 43 GW of four-hour battery storage capacity by 2050. In 2022, New England states had just 4.07 GW of renewables: 0.03 GW of offshore wind, 1.5 GW of onshore wind, 2.24 GW of utility-scale solar, and 0.30 GW of battery storage.[42]

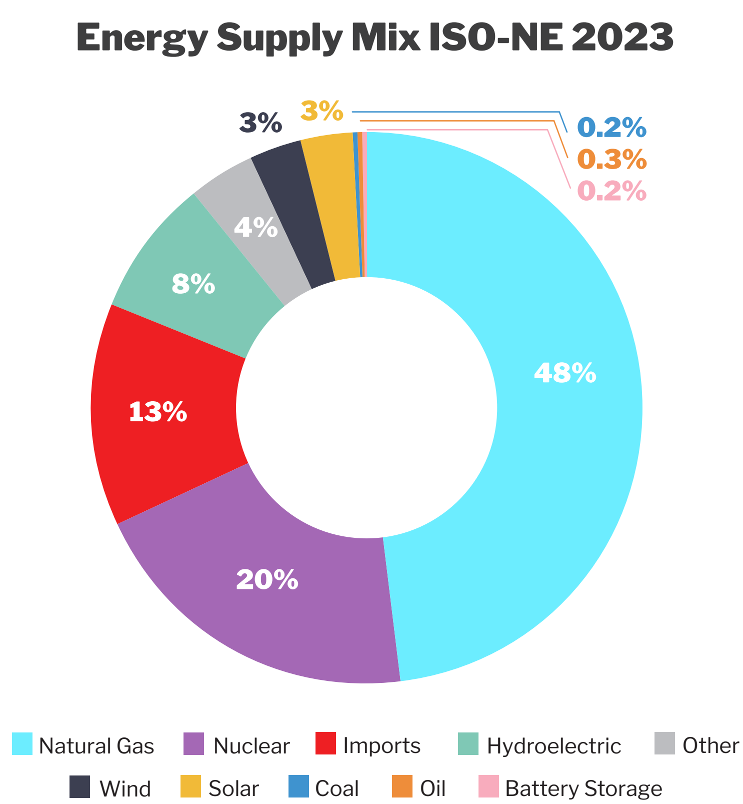
For context, there are 1,000 MW in one GW, meaning New England will need 2,277 times more offshore wind capacity, 12.4 times more onshore wind capacity, 30.5 times more solar capacity, and 142 times more battery storage in the next 26 years than were in operation on the grid in 2022.

SECTION II

Impacts of Decarbonization Policies on ISO-NE Electricity Production

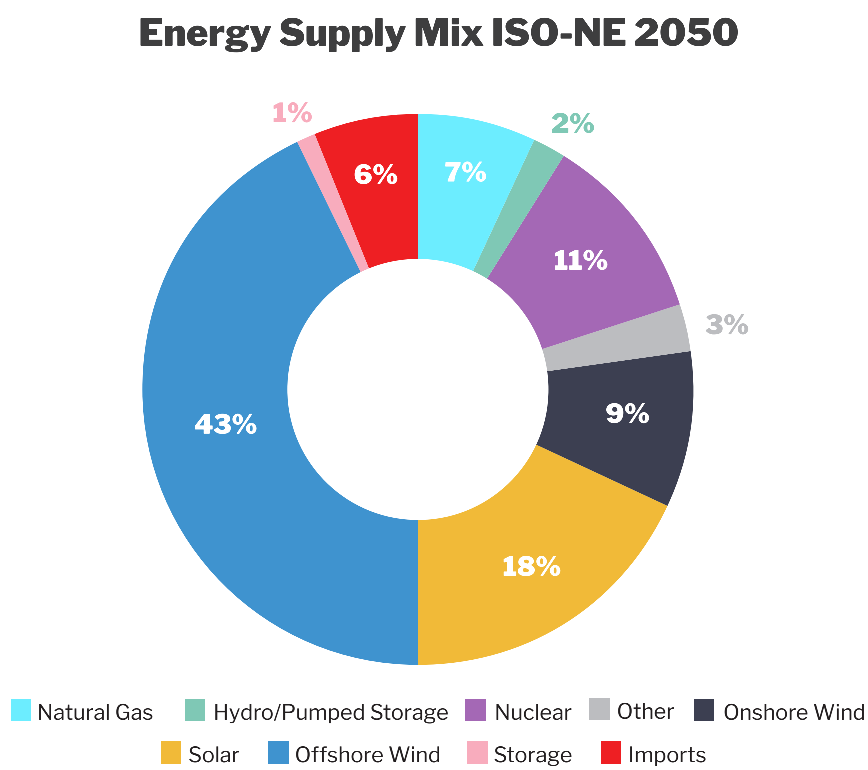
The policies designed to decarbonize the power grid will have a profound impact on the way New Englanders produce their electricity.

In 2023, ISO-NE sold 114.7 million megawatt hours (MWh) of electricity.[43] According to the Internal Market Monitor (IMM) for ISO-NE, 48 percent of the region's electricity was generated at natural gas fired power plants in 2023, 20 percent from nuclear power, 13 percent from net imports (New England exported some generation) — largely hydro imports from Hydro Quebec— 8 percent was from in-region hydroelectric power; 4 percent was "other"; 3 percent was wind; 3 percent solar; and



SOURCE: ISO-NE Internal Market Monitor

FIGURE 1. Natural gas and nuclear power produce the largest share of electricity in New England, followed by imports and hydroelectric power. Wind and solar each produced 3 percent of the total electricity consumed in the region.



SOURCE: ISO-NE Internal Market Monitor

FIGURE 2. Offshore wind becomes the largest source of electricity in New England.

coal, oil and battery storage constituted 0.2, 0.3, and 0.2 percent of the region's electricity supply, respectively. (See Figure 1)[44]

This resource mix will change substantially due to the policies of the five decarbonizing states. Our modeling indicates total electricity consumption will explode from 114.7 million MWh in 2023 to 244.4 million MWh by 2050.

Figure 2 shows the ISO-NE resource mix in 2050, when the decarbonization mandates go into full effect. Our modeling indicates that in 2050, the energy mix will consist of 43 percent offshore wind, 18 percent solar, 11 percent nuclear, 9 percent onshore wind, 7 percent natural gas, 6 percent imports, 1 percent battery storage, 2 percent hydroelectric and pumped storage, and 3 percent other.

The natural gas remaining on the system serves electricity demand in New Hampshire, which will see an increase in natural gas capacity to meet any future increases in demand. Figure 3 shows the change in electricity generation over time.

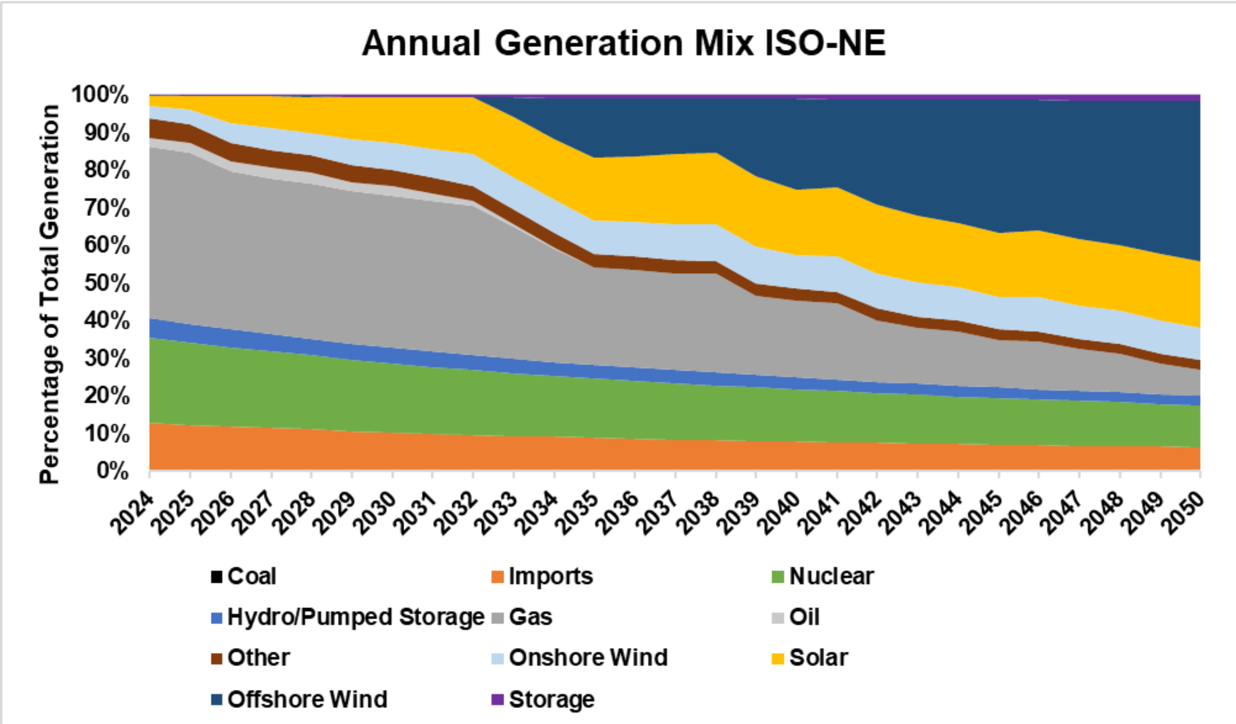


FIGURE 3. Offshore wind and solar have become the largest energy sources under the energy policies of the New England states. Existing nuclear plants continue to operate but constitute a smaller share of overall generation as demand for power increases due to the electrification of transportation and home heating.


24.106
26.789
38.295
67.901
26.789
93.095
40.381
56.297
24.106

SECTION III

Energy Demand

ISO-NE expects a substantial increase in the total amount of electricity consumed in the coming decades due to the economy-wide decarbonization mandates in the five decarbonizing states. Our analysis finds that electrifying the transportation and home heating sectors will cause ISO-NE's annual electricity consumption to grow by 106 percent by 2050. Furthermore, ISO-NE's *2050 Transmission Study* estimates the region will become a winter-peaking system in 2035.[45]

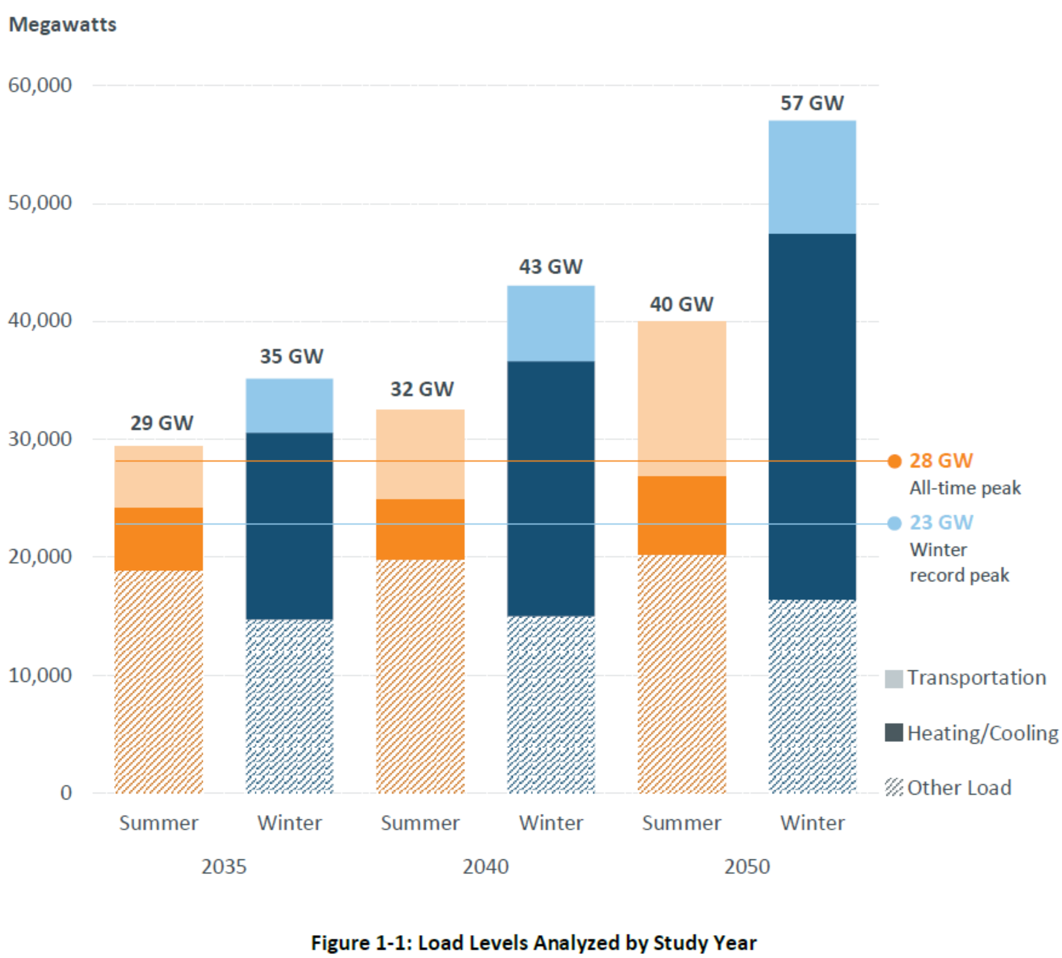


FIGURE 4. This figure shows peak electricity demand in Gigawatts(GW).

However, the increase in electricity use for transportation and home heating will drive peak electricity demand substantially higher than it is today. According to the Internal Market Monitor, the average hourly electricity demand in 2023 was 13 GW, with a peak demand of 24 GW.[46] By 2050, winter peak demand could hit 57 GW, more than doubling the current winter peak record of 23 GW.[47] (See Figure 4)

Our analysis adopts many of the same assumptions as the *2050 Transmission Study* by assuming the five states with decarbonization policies will completely adopt electric vehicles and electric home heating systems. However, our modeling assumes New Hampshire residents will continue to use natural gas power plants as well as conventional home heating systems and internal combustion engines. This results in reducing peak electricity demand by 4,457 MW on the ISO-NE system for a new total peak demand of 52.5 GW.

Meeting these new peak electricity demands will require a massive increase in the amount of power plant capacity on the ISO-New England power system.

SECTION IV

Calculating the Cost of the New England Decarbonization Plans

New England residents already pay some of the highest electricity prices in the country. The region's state Decarbonization Plans would cause these prices to rise significantly.[48]

Our modeling indicates that complying with the New England Decarbonization Plans will cost an additional $815 billion over the next 26 years (in constant, inflation adjusted, 2023 dollars) compared to operating the current electric grid.[49] This figure does not include federal subsidies This would more than double electricity prices, with all-sectors electricity rates rising from 22.78 cents per kilowatt hour (kWh) in 2023 to 51.58 cents per kWh in 2050 — an increase of 28.79 cents per kWh.

As a result, the average annual electricity cost for each New England utility customer — a total including residential, commercial, and industrial customers — would increase by $4,218 from 2024-50, an average of $162.23 every year (see Figure 5).

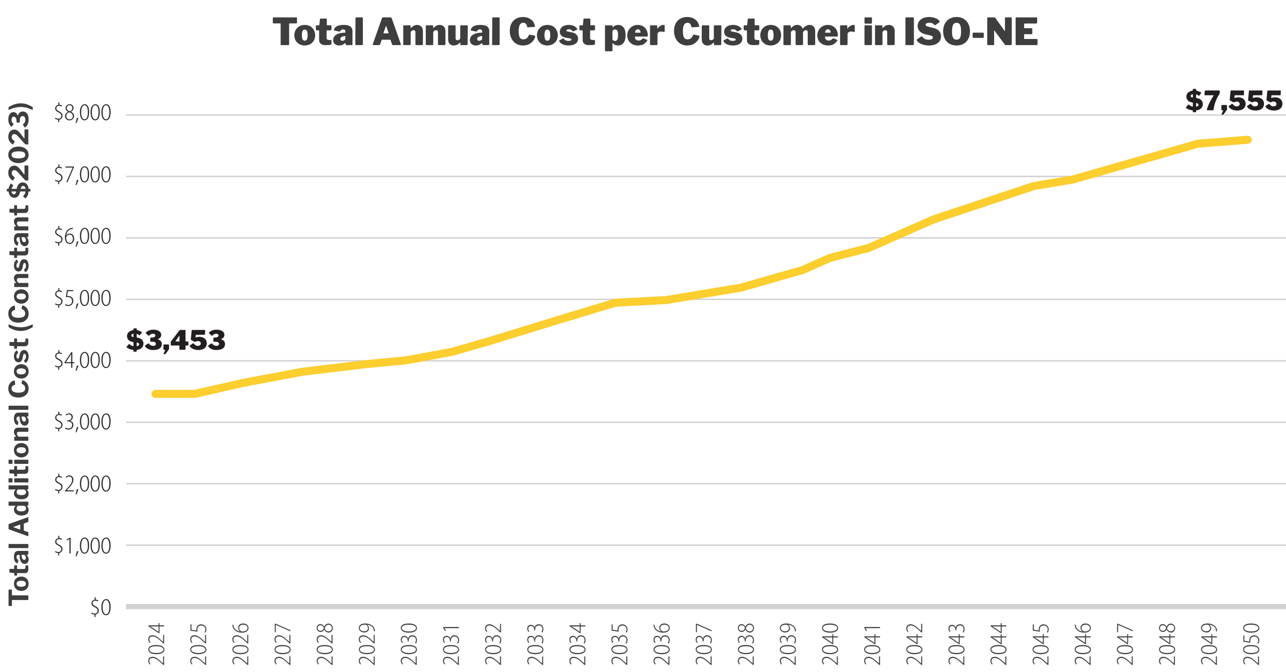


FIGURE 5. Costs for New Englanders increase by an average of $162 annually under the New England Decarbonization Plans. Total costs peak at $4,218 above the 2024 level in 2050.

Figure 5 shows the average additional cost of complying with the New England Decarbonization Plans from 2024 through 2050, compared to the current cost of electricity. This number is obtained by dividing the overall costs of the mandates among all New England utility customers, including residential, commercial, and industrial electricity users by the number of years examined. The New England Decarbonization Plans immediately increase electricity costs as offshore wind, onshore wind, solar, battery storage and transmission projects are built.

It is important to note that these rate analyses do not calculate the cost savings that would accrue to New Hampshire residents by continuing to use natural gas for power generation.

Generating more electricity is relatively easy with dispatchable power plants — plants that can be turned up or down on command — like those powered with coal, natural gas, nuclear fuel, or hydroelectric plants. But adjusting to second-by-second fluctuations in electricity demand is much more difficult with wind and solar, whose electricity production is subject to second-by-second fluctuations in the weather. As a result, it is much more difficult to provide reliable power as regions become more reliant upon wind and solar to meet their energy needs.

It is possible to mitigate some of the inherent unreliability of wind and solar by vastly increasing the amount of wind and solar capacity on the grid (known as "overbuilding" wind and solar installations) to allow electricity demand to be met even on cloudy or low-wind days, and curtailing, or turning off, much of this capacity when wind and solar production is higher. Other mitigation strategies include building more transmission lines and battery storage facilities. Each of these mitigation strategies, however, is a major cost driver for the entire electric system.

These mitigations come with other additional costs, including higher profits for transmission and distribution companies and higher state and federal taxes. Each of these additional costs will be discussed in greater detail in the ensuing sections.

Residential Customers

Under the New England Decarbonization Plans, residential electricity prices would more than double by 2050, causing New England families to see their annual electricity costs increase by $2,574 above 2024 costs, an increase of $214 per month (see Figure 6). While these costs are projected to increase in some years more than others, New England households can expect to see their electric bills increase $99.04 every year from 2025 to 2050.

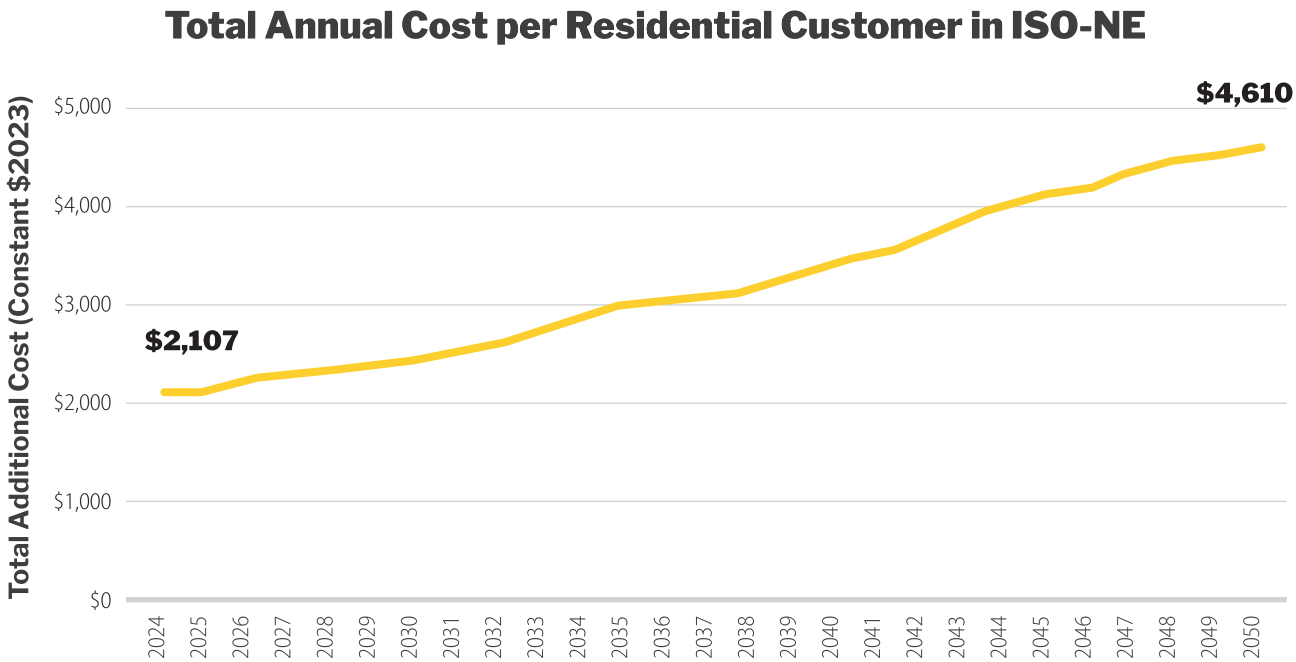


FIGURE 6. New England families would see their electric bills increase by an average of $99 per year.

Commercial Customers

New England's commercial customers currently use about 45% of its electricity. Under the New England Decarbonization Plans, small businesses, grocery stores and other retailers would see their electricity costs increase $12,726 by 2050 — or an average of $489.46 per year from 2025 to 2050. (see Figure 7).

These higher electricity costs would likely be passed on to consumers in the form of higher prices for goods and services.

Industrial Customers

Industrial companies in New England, such as manufacturers, used roughly 13% of the electricity consumed in the region in 2023.[50] Under the New England Decarbonization Plans, electricity costs for these firms would rise by an average of $5,280 every year, with costs reaching $137,275 above 2024 costs in 2050 (see Figure 8).

Meanwhile, academic research suggests that high electricity costs play a role in investment decisions made by companies to relocate their facil-

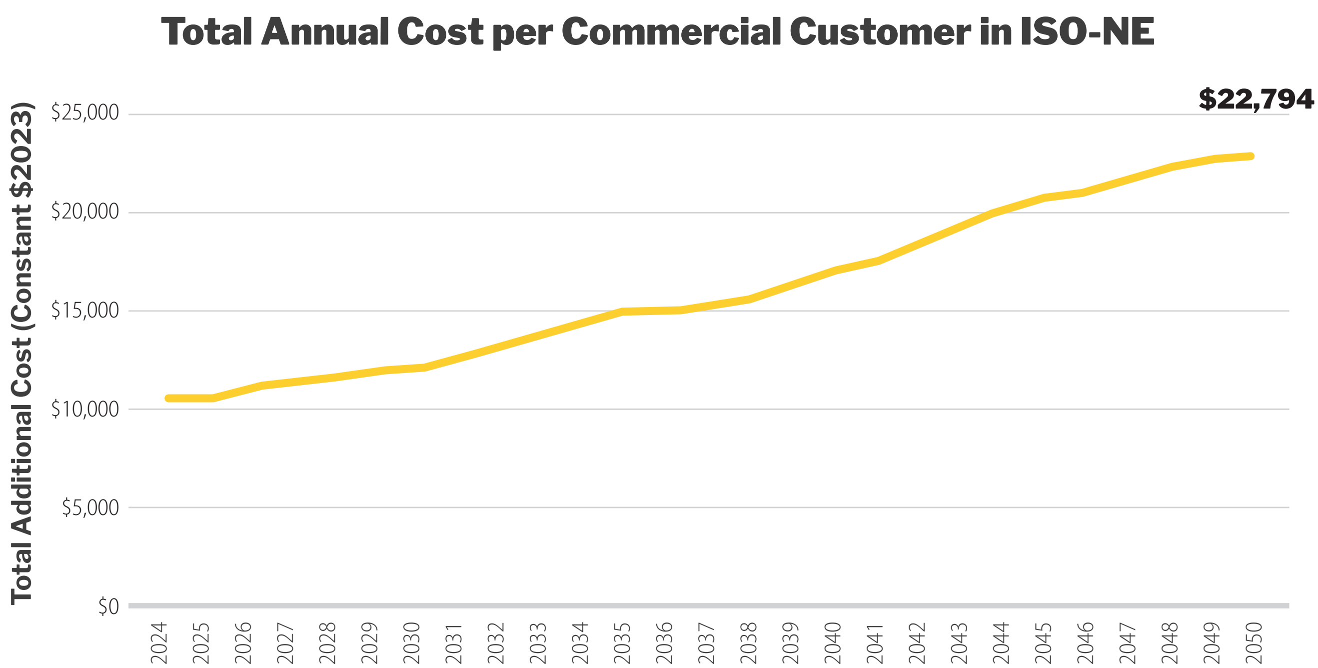


FIGURE 7. Costs for commercial customers, such as small businesses, rise quickly, at $490 every year, peaking at $12,726 in 2050.

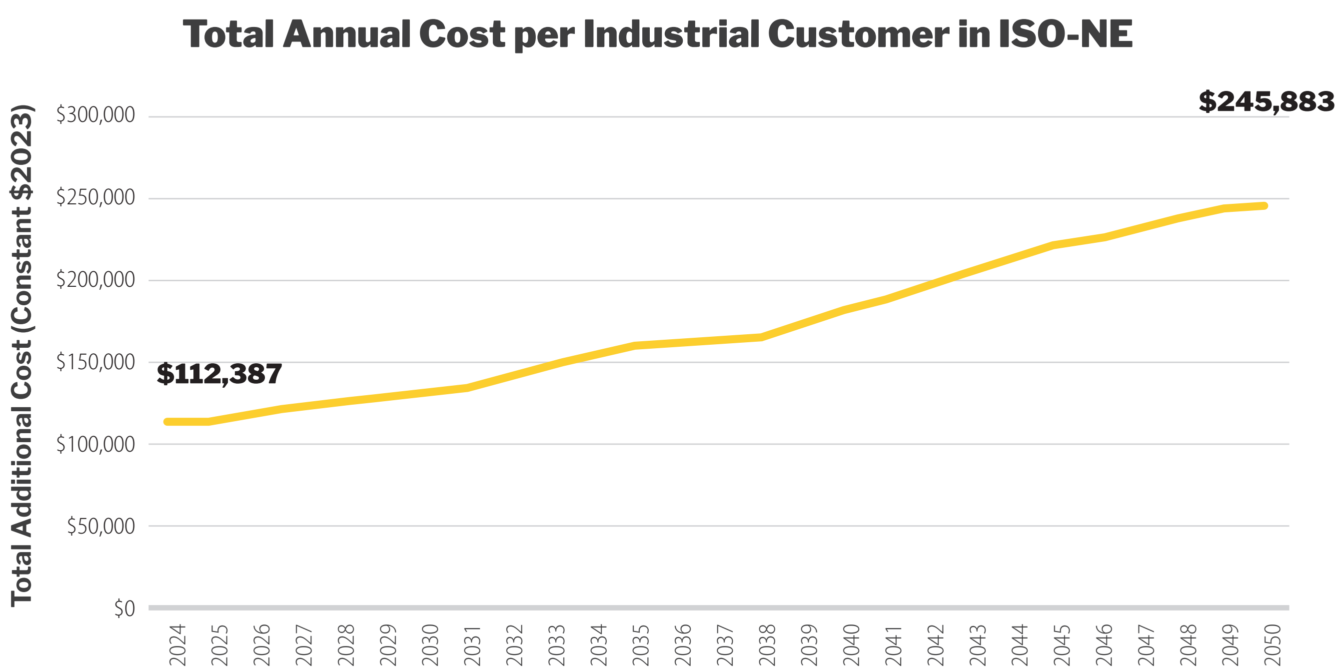


FIGURE 8. Industrial electricity consumers would experience cost increases of $137,275 over the next 26 years, averaging $5,280 per year under the New England Decarbonization Plans.

ities.[51] If electricity prices for businesses in New England become overly burdensome, it may incentivize these companies to relocate to lower-cost locations.

Additionally, New England Decarbonization Plans compliance costs are driven by the need to build enough offshore wind turbines, onshore wind turbines, solar panels, battery storage facilities and transmission lines to meet the emissions requirements stipulated in the decarbonization policies enacted by the five states.

Other factors that increase costs include the cost of building new generation assets. Figure 9 shows that on a per-capita basis, the cumulative cost of the plans increases expenses for each person in New England by an additional $2,061 in 2030, $15,552 in 2040, and an additional $51,914 in 2050.

Using these per-capita figures, we can estimate how much each state can expect to pay of the $815 billion total cost, as seen in Figure 10. Using state-level population forecasts for 2030, 2040 and 2050 from the non-partisan Weldon Cooper Center, the premier organization in charge

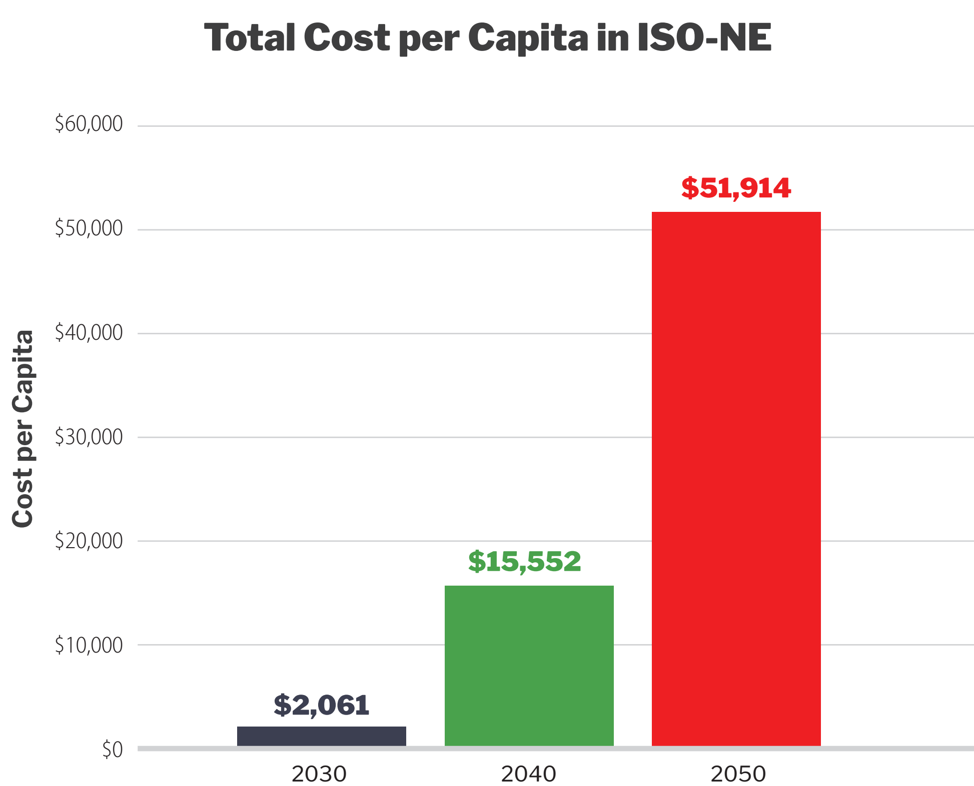


FIGURE 9. Total Cost per Capita in ISO-NE

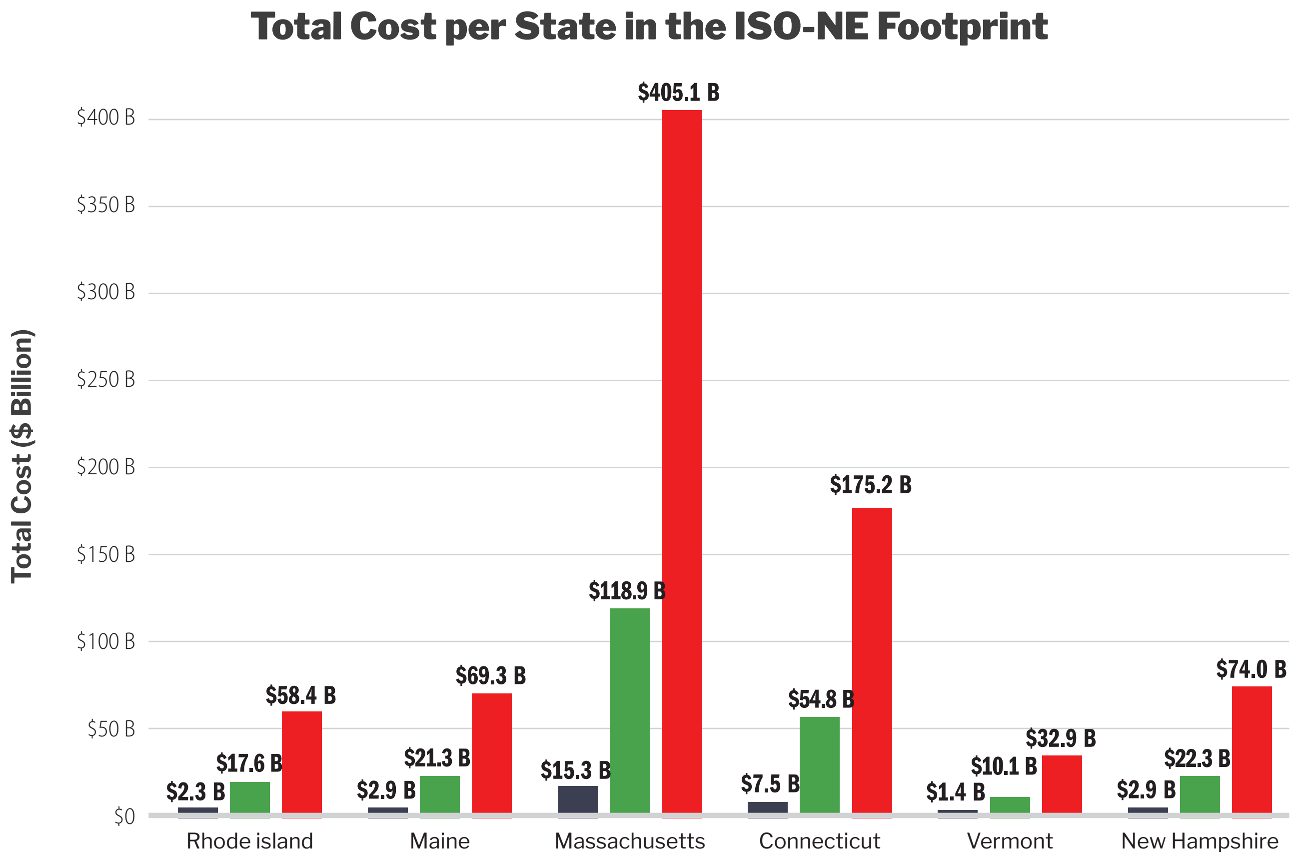


FIGURE 10. Total costs per state under 225 GW buildout scenario.

of population projects based on US Census data, we estimated that Massachusetts would pay the most: $405.1 billion in imposed costs by 2050.[52] Connecticut comes in second, with $175.2 billion in imposed costs. New Hampshire ($74 billion), Maine ($69 billion), Rhode Island ($58.4 billion) and Vermont ($32.9 billion) account for the remaining estimate.

Of course, the costs for a resident of an individual state will vary beyond per-capita cost calculations due to several factors. States that serve more rural customers may have to build more transmission lines and pass those costs on to ratepayers. States with more aggressive emission reductions goals will incur higher costs on behalf of ratepayers (such as Massachusetts and Vermont), while states with less aggressive reduction goals will incur lower costs for ratepayers (New Hampshire).

SECTION V

How Offshore Wind, Onshore Wind, Solar, and Battery Storage Facilities Drive Up Costs Compared to Reliable Power Plants

Thus far, this report has summarized the cost difference between the New England Decarbonization Plans and using New England's existing power plants. In this section, we will discuss how attempting to run a reliable electric grid using mostly offshore wind, onshore wind, solar, imports and battery storage drives up costs to a much greater extent than building a grid using reliable power plants.

The most important thing to know about the electric grid is that the supply of electricity must be in perfect balance with demand at every second of every day.[53] If demand rises as New Englanders turn on their air conditioners, heaters or charge their electric vehicles, an electric company must increase the supply of power to meet that demand. If companies are unable to increase supply to meet demand, grid operators are forced to cut power to consumers — i.e., initiate brownouts, a temporary reduction in voltage levels that causes lights to dim and appliances to malfunction or shut down. In a worst-case scenario, an electric company could resort to blackouts, a complete loss of power that can cause all lights and appliances to shut down, to keep the entire grid from crashing.

It is possible to mitigate some of the inherent unreliability of wind and solar by vastly increasing the amount of wind and solar capacity on the grid (known as "overbuilding" wind and solar installations) to allow electricity demand to be met even on cloudy or low-wind days, and curtailing, or turning off, much of this capacity when wind and solar production is higher. Other mitigation strategies include building more transmission lines and battery storage facilities. Each of these mitigation strategies, however, is a major driver of cost for the entire electric system.

These mitigations come with other additional costs, including higher profits for transmission and distribution companies and higher state and federal taxes. Each of these additional costs will be discussed in greater detail in the ensuing sections.

Increasing Electricity Generation Capacity

Building and operating new power plants is expensive. The New England Decarbonization Plans would greatly increase the amount of new

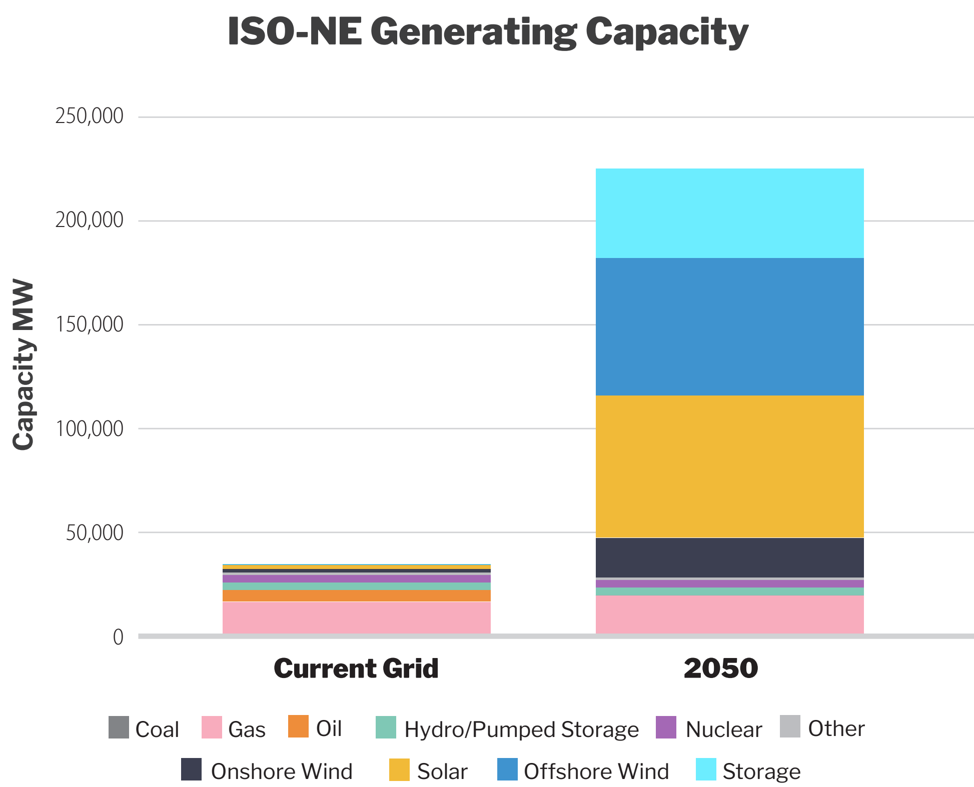


FIGURE 11. According to our analysis, complying with the New England Decarbonization Plans would require almost 6.4 times more installed capacity on the New England electric grid to maintain a reliable system, based on 2023 wind and solar output. This massive buildout of capacity would drive significant cost increases for families and businesses.

power plant capacity on the New England electric grid, which is why the plans are so costly.

In 2022, New England had roughly 35,500 MW of installed power plant capacity on the grid and could draw from 4,475 MW of import capacity — supplying 13 percent of electricity in ISO-NE — to meet electricity demand. These imports come from neighboring control areas like New York and even Canada.54

Under the New England Decarbonization Plans, our modeling indicates that the amount of installed power plant capacity in New England would need to increase from 35,500 MW in 2022 to 225,400 MW by 2050 (not including imports). This means the New England Decarbonization Plans would require nearly 6.4 times more power plant capacity than is currently used to meet New England's electricity demand. (See Figure 11)

Offshore wind installations under the New England Decarbonization Plans would increase from 30 MW of installed capacity in 2022 to 66 GW of capacity in 2050. Onshore wind would increase from 1,546 MW to 19.2 GW. Solar capacity would grow from 2,242 MW to 68.4 GW, and battery storage would increase from 303 MW to 43 GW, with four hours of storage per MW (See FIGURE 11). Additionally, transmission capacity to neighboring regions would grow from 4,475 MW to 6,675 MW, but these figures are not reflected in Figure 11.55

A portion of the extra wind and solar power must be used to charge the batteries. Once the batteries are fully charged, any additional solar or wind power that is generated is curtailed or turned off. Curtailment is expected to become increasingly common in New England and the nation as more wind and solar facilities are placed into service on the grid.56,57

It is important to note that our model selected these quantities of solar, offshore wind, onshore wind and battery storage resources because they were the most cost-effective portfolio for meeting the carbon-free energy mandates proposed by New England states, while also maintaining grid reliability under 2023 wind and solar generation conditions and future hourly load profiles derived from data obtained from ISO-NE's website58

Building these solar panels, offshore wind turbines, onshore wind turbines and battery storage facilities would cost \$104 billion, \$334 billion, \$35 billion, and \$78 billion, respectively, while repowering these facilities at the end of their 20- to 25-year useful lives would cost an additional \$51.8 billion. The additional transmission lines would cost \$23.5 billion, but have a useful service life beyond the scope of this analysis and would not need to be rebuilt.

Our analysis finds that the ISO-NE grid would require substantially more capacity than shown in the Economic Planning for the Clean Energy Transition report released by ISO-NE in August 2024. That analysis estimated a need for 97 GW of onshore wind, offshore wind, solar and battery storage and 30 GW of existing dispatchable resources, such as natural gas or nuclear power, to meet future decarbonization goals.

It is important to note that Economic Planning did not perform a resource adequacy analysis. It was a report designed to estimate the amount of capacity needed to meet a target of reducing 1 million tons of CO2 from fossil resources.

Based on the hourly load profiles used in our analysis, this resource portfolio would not be sufficient to maintain reliability during periods of low wind and solar output, even when 20,454 MW of natural gas are retained (See Figure 12). Not shown in the graph are the 6,675 MW of "firm transmission" resources.

ISO-NE Generating Capacity: ISO-NE EPCET Report vs. Modeled Capacity Requirement

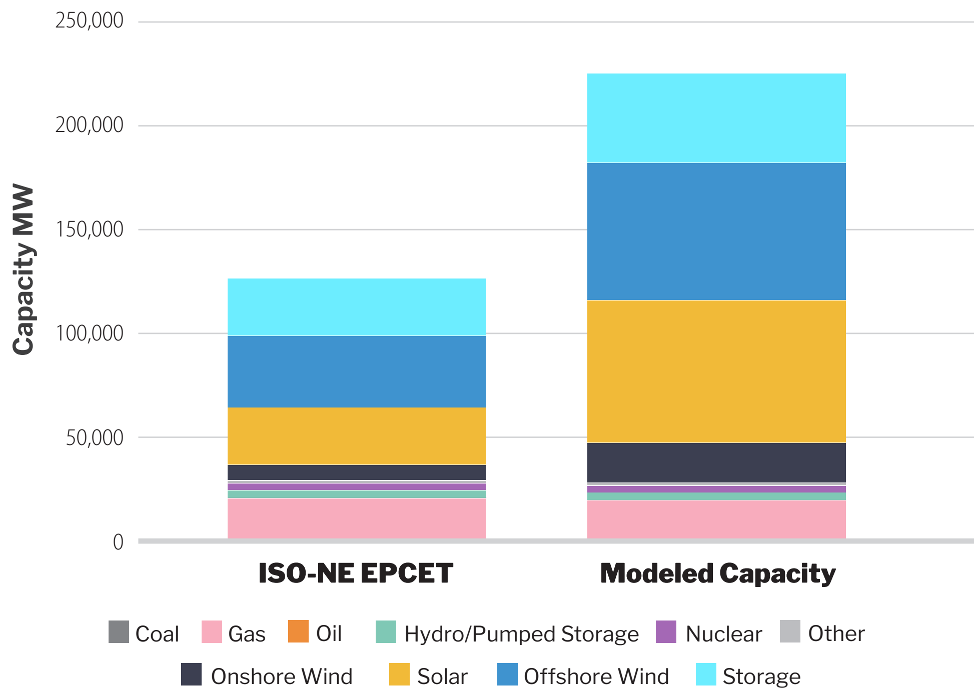


FIGURE 12. The ISO-NE study has less total installed capacity than our modeling indicate will be necessary to maintain reliability based on historical wind and solar output and projected future hourly load shapes.

Figure 13 shows the electricity provided by each resource from December 15 through December 19 in 2050, at a period in time when electricity demand is expected to be the highest, based on the data from ISO-NE. This is commonly referred to as "peak electricity demand." Electric grids must be built to accommodate this demand plus a margin of safety — called a "reserve margin" — much in the same way a bridge must be built to handle its maximum capacity plus a factor of safety, making it stronger than its expected maximum load.

This graph, which is based on 2023 real-world output data for onshore wind and solar in the ISO-NE region and variable energy resource data from ISO-NE for 2019 for offshore wind, shows a hypothetical week in 2050 under the New England Decarbonization Plans.[59] Hourly electricity demand profiles were obtained from the 2024-2033 NE Region hourly load forecast, and values were adjusted upward to meet a projected peak demand of 52.5 GW in this report.[60]

ISO-NE Hourly Electricity Supply During Peak Demand in 2050 Using 2019 Wind and Solar Output

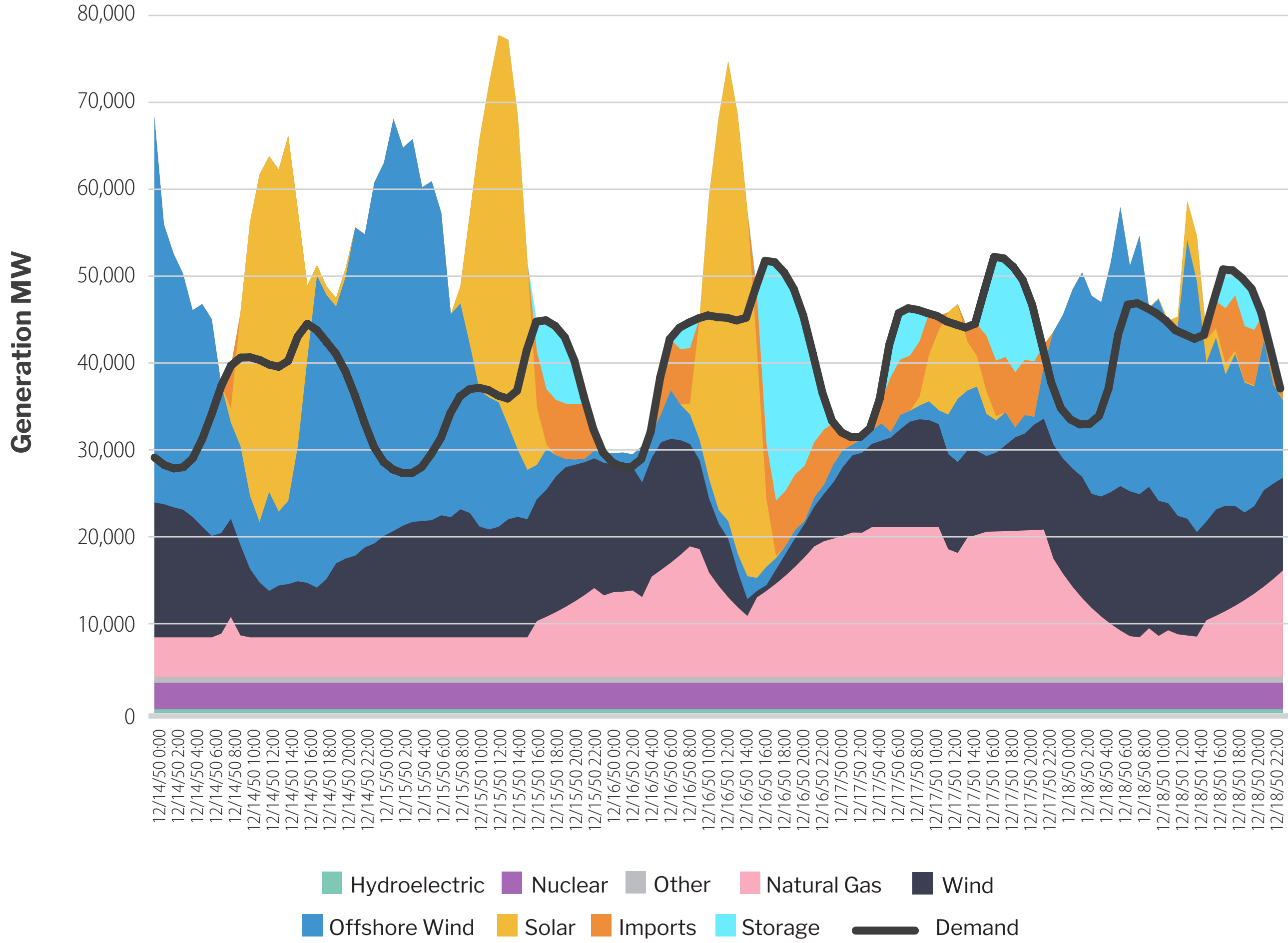


FIGURE 13. Battery storage is needed to help meet electricity needs during periods where wind and solar generation is insufficient to meet demand. The batteries are charged by the solar panels and wind turbines when their generation exceeds the black demand line and discharged when wind and solar are unavailable. This analysis uses data from the ISO-NE Variable Energy Database. 2023 hourly generation data for onshore wind and solar were used and 2019 data were used for offshore wind because more recent data was not available.

The black line shows hourly electricity demand throughout the week. Solar generation, shown in yellow, increases in the morning, peaking in mid-afternoon, before falling off in the early evening. Offshore wind generation is shown in dark blue, and onshore wind is shown in light blue. Generation from these resources varies considerably based on wind speeds. Battery storage, shown in purple, provides electricity during the hours when wind and solar generation is insufficient to meet electricity

Capacity Factors for Wind and Solar and Charge of Battery Storage During 2023 Peak Demand

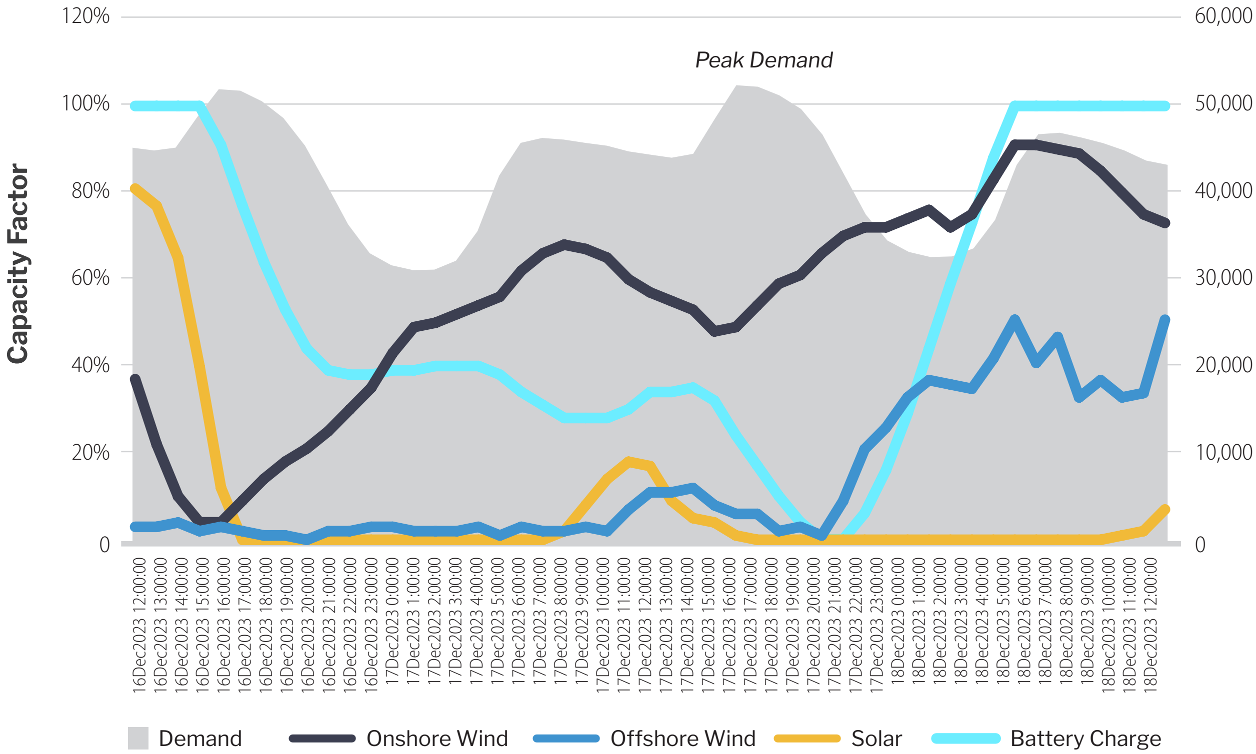


FIGURE 14. During a 36-hour period stretching from noon on December 16 until midnight on December 17, 2023, the offshore wind on the ISO-NE system performs at an average capacity factor of 4.9 percent.

demand, with imports, shown in orange, also filling in the gaps.

Our modeling determined 225.4 GW of total capacity would be necessary to meet electricity demand during this period because the region experiences low solar and offshore wind production during the peak demand period.

Figure 14 shows electricity demand, capacity factors for solar, onshore wind, offshore wind and the charge percentage of battery resources from 12:00 p.m. on December 16 through 12:00 p.m. on December 18 in 2023.

From 12:00 p.m. to 6:00 p.m. (18:00), onshore wind, offshore wind, and solar generation fall substantially, leading the battery charge to fall from 100 percent on to 80 percent, and the battery charge falls further in the ensuing hours as solar and offshore wind generation — which constitute 60 percent of the total installed capacity in our modeled system — are effectively zero until 8:00 a.m. on December 17.

ISO-NE EPCET Report Capacity Buildout During Peak Demand in 2050 Using 2023 Wind and Solar Output

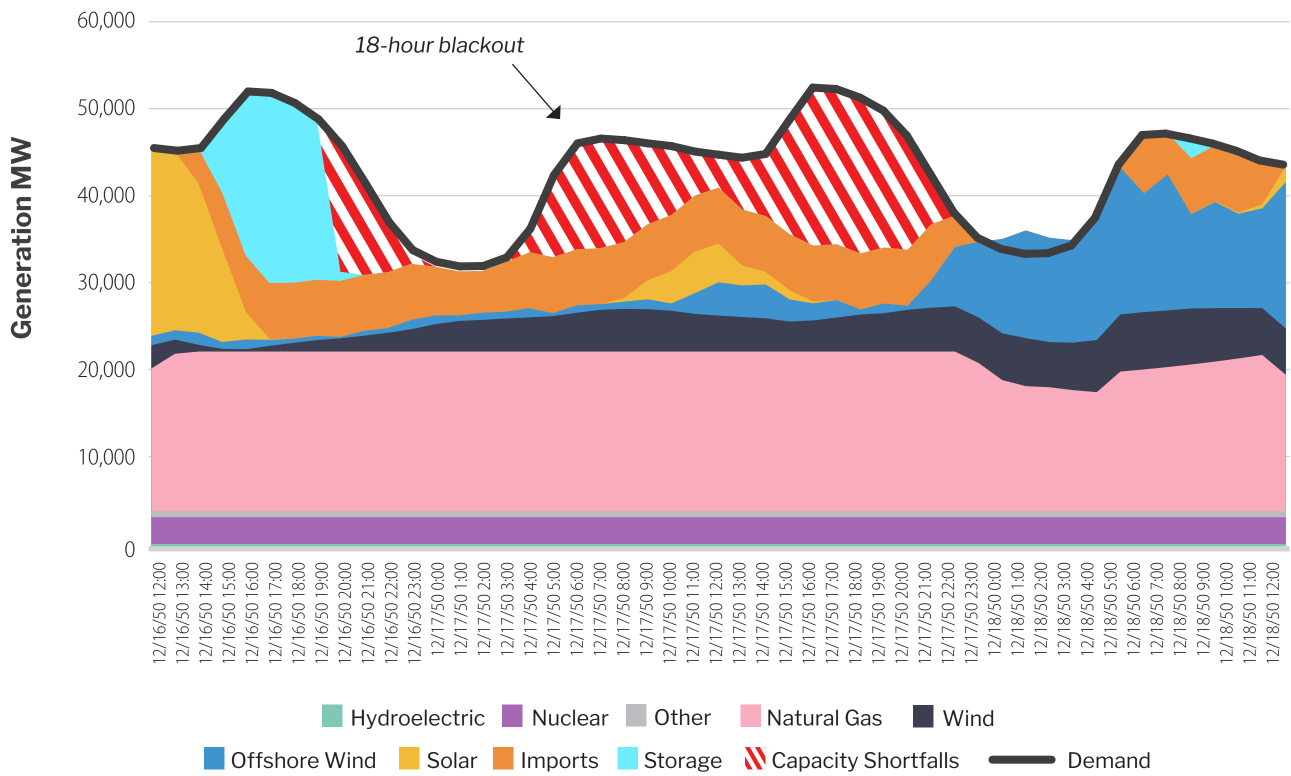


FIGURE 15. The capacity buildout in the EPCET report is insufficient to maintain reliability during peak demand.

The battery storage is drained further as solar generation on December 17 reaches a capacity factor of just 18 percent, which is 4.4 times less than the solar output observed on December 16. Additionally, electricity demand increases to 52.5 GW at 4:00 PM (16:00) on December 17, resulting in a situation where demand is highest but offshore wind and solar resources are producing almost no electricity. It should be noted that onshore wind performs well during this stretch, which is why our model selects more onshore wind for the resource portfolio to add operational diversity.

Using these same hourly electricity demand and capacity factors, the grid in ISO-NE's Economic Planning for the Clean Energy Transition report would be unable to meet the hourly electricity demand. Figure 15 uses battery storage assumptions provided by ISO-NE (14,664 MW four-hour storage and 13,000 MW eight-hour storage), but the low offshore wind and solar output during the time period studied results in massive capacity shortfalls (i.e., significantly more capacity will be necessary to decarbonize the ISO-New England system).

As you can see, offshore wind experiences a large drought where it produces, on average, 4.9 percent of its total capacity, and solar experiences a dramatic reduction in output on December 17 compared to the day before. Due to the lack of dispatchable capacity to charge the batteries, available storage is fully depleted and is unable to recharge because all available resources, including imports, are being used to meet demand. As a result, an 18-hour capacity shortfall event occurs starting at 3:00 a.m. on December 17 and lasting until 9:00 p.m. on December 17. The maximum hourly shortfall reaches as high as 18,125 MW right as peak demand occurs at 4:00 PM, representing 35 percent of the system demand.

Transmission Costs

Transmission lines are important. It does no good to generate electricity if it cannot be transported to the homes and businesses that rely upon it.

Transmission costs are driven by the need to build new infrastructure to connect ISO-NE to Hydro Quebec, connect new offshore and onshore wind turbines and solar panels to the rest of the electric grid, and allow for greater interregional connectivity within New England.

The ISO-NE *2050 Transmission Study* estimates the region will require extensive upgrades to the regional transmission network to accommodate the state Decarbonization Plans. In addition to making upgrades to the network of existing transmission lines, the *2050 Transmission Study* estimates the completion of two additional international transmission lines, including the completion of the 1,200 MW New England Clean Energy Connect High Voltage Direct Current (HVDC) line, and a hypothetical 1,000 MW HVDC line connecting Quebec and Vermont.[61]

ISO-NE estimates rising peak demand will cost roughly $750 million per gigawatt (GW) of load added from 28 GW to 51 GW, and roughly $1.5 billion per GW from 51 GW to 57 GW. (See Figure 16)[62]

ISO-NE notes the New England grid with 100 percent heating and transportation electrification is expected to result in a peak load of around 57 GW, but a lower peak load could be achieved with less electrification of the transportation and home heating sectors.

In our analysis, New Hampshire serves to reduce peak load by nearly 4.5 GW by continuing to heat homes with natural gas and fuel oil and by continuing to use internal combustion engines.[63,64] As a result, the necessary increase in transmission spending grows to $22.8 billion by 2050.

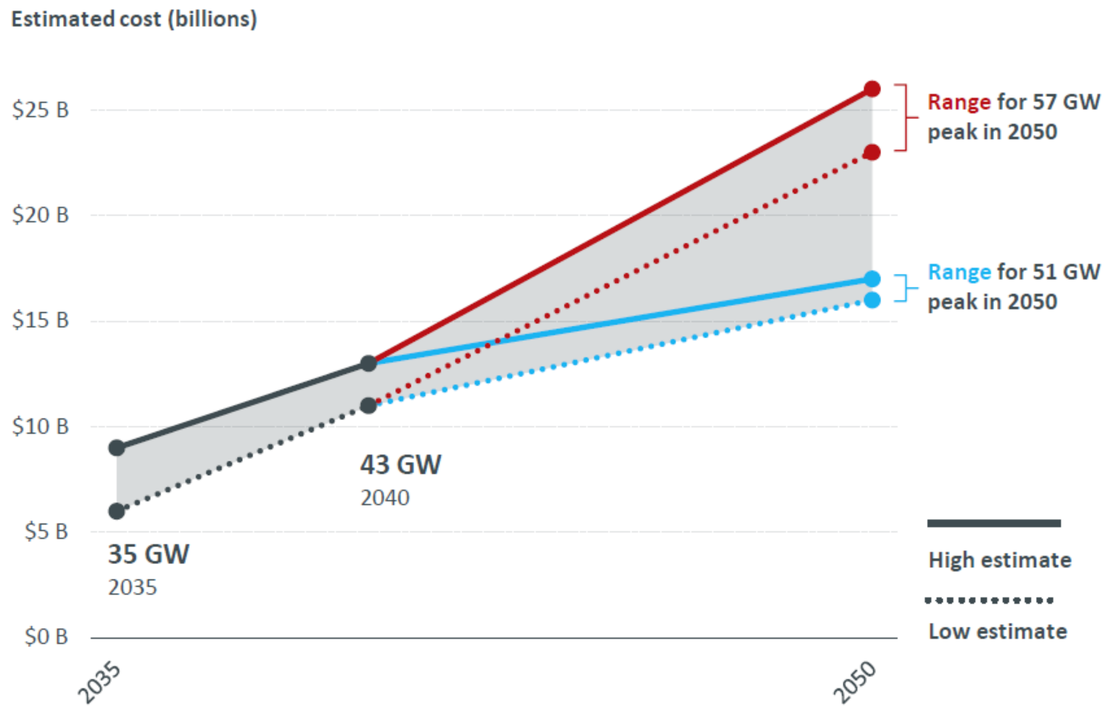


FIGURE 16. Transmission costs would increase substantially to accommodate a peak load of 57 GW.

Generator Profits

Unlike other areas of the country where monopoly utilities own generation, transmission, and distribution of electricity, power generators in ISO-NE are not monopolies and therefore they are not entitled to recover the cost of providing service to ratepayers with a government-approved return on investment. Instead, generators sell their power and reliability attributes into the wholesale energy, capacity and ancillary service markets.

However, according to ISO-NE, several states have established public policies that direct electric power companies to enter ratepayer-funded, long-term contracts for large-scale carbon-free energy that would cover most, if not all, of the resource's costs.[65] These contracts must be lucrative enough to attract investment to the industry and allow companies to recover the upfront capital cost of the generators with a reasonable rate of return for shareholders.

As these carbon-free resources produce increasing amounts of electricity on the grid, they are expected to reduce the wholesale clearing prices for all generators, including new wind and solar generators[66,67] While there are advantages to lower wholesale energy costs, the trend toward lower, and potentially negative, clearing prices will deprive dispatchable generators of some of the revenue needed to remain on the system for the important periods when there is low wind or solar generation, which can collapse the competitive energy market.

This is why the *Economic Planning for the Clean Energy Transition* document released by ISO-NE stated that dispatchable units that are infrequently run may result in these generators receiving more of the revenues needed to operate the plant through capacity and ancillary service markets. These generators may also obtain separate contracts to remain on the system to generate electricity when it is needed, as was the case for the Mystic Generating Station.[68,69]

ISO-NE notes: "During the final years of analysis, the majority of revenue for all generators is earned through either the capacity market or out-of-market PPAs."[70] Therefore, we at Always On Energy assumed that all generation assets built in our model would be able to recover their upfront capital costs, with a 7.05 percent return on investment.

As a result, additional generator profits stemming from the New England Decarbonization Plans are $323 billion through 2050.

Additional Property, State and Federal Taxes

Property tax collections increase under the New England Decarbonization Plans because compared to the current grid, there is much more property to tax. While the property taxes assessed on power plants are often a crucial revenue stream for local communities that host power plants, these taxes also effectively increase the cost of producing and providing electricity for everyone.

Some New England states exempt renewable energy facilities from property taxes entirely, while others assess a "payment in lieu of tax" payment on these facilities, and in some jurisdictions these facilities are taxed at normal rates. To simplify these differences, this model assumes a property tax rate of 1 percent of net capital investment (gross plant value minus depreciation).

Additionally, state and federal income taxes increase due to the growth in income for power producers in the region. As a result, additional taxes are $115 billion through 2050.

Summary of Costs

While New England will experience modest declines in fossil fuel expenditures through 2050, $14.8 billion through the model run, these savings are far outweighed by the additional capital costs, fixed operations

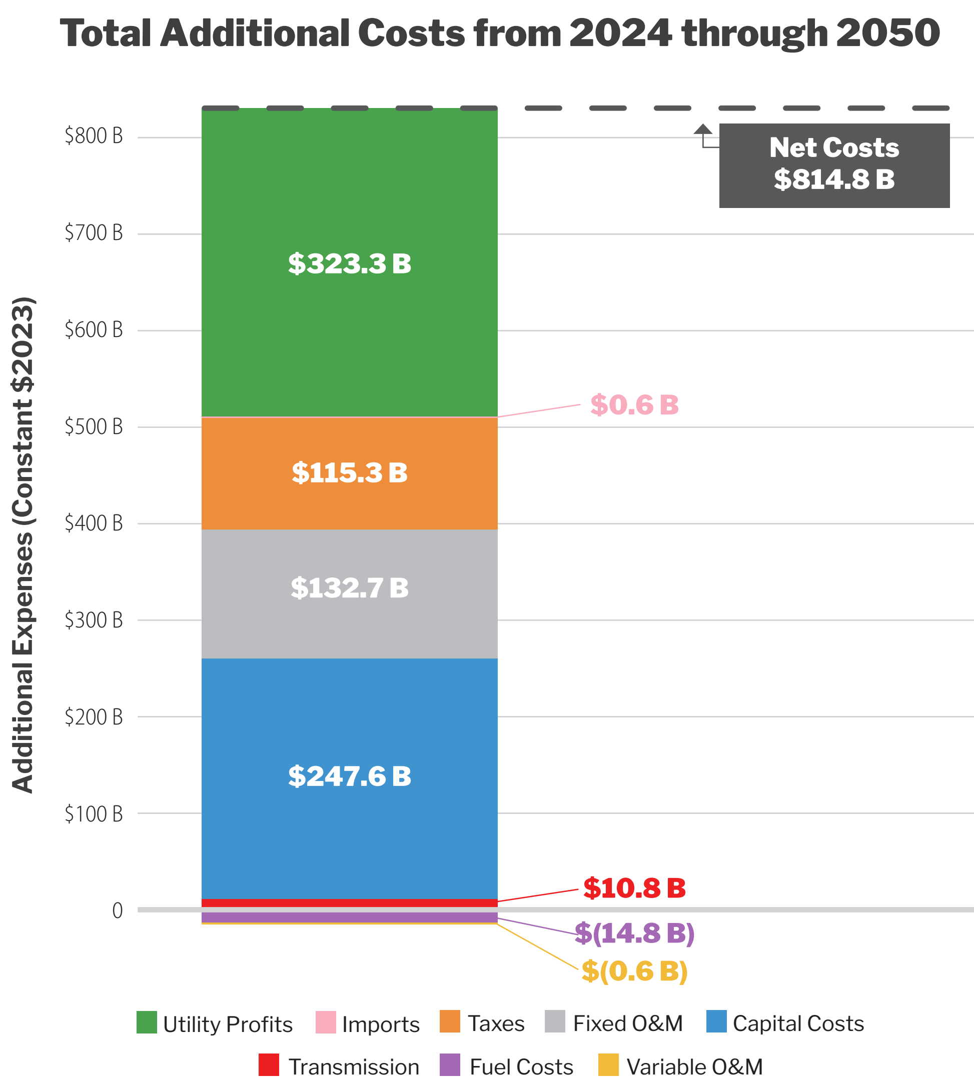


FIGURE 17. The total cost would be $814.8 billion through 2050.

and maintenance costs, taxes, and the need for out-of-market purchase power agreements (utility profits). These costs result in a net expenditure of $814.8 billion through 2050. (See Figure 17)

What's the Cost to ISO-NE if New Hampshire Pursues Net Zero?

In this analysis, New Hampshire's energy policies produce substantial benefits for the entire ISO-NE region. The Granite State's lack of electrification mandates for transportation and home heating reduces the pro-

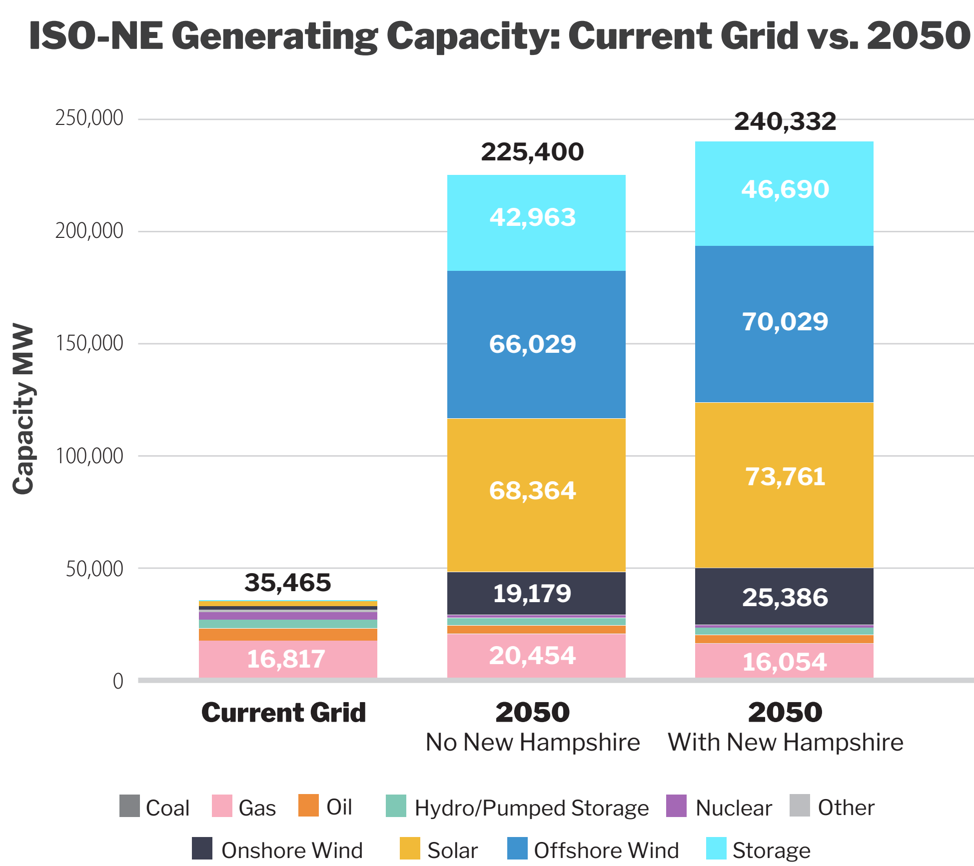


FIGURE 18. No New Hampshire shows the capacity needed if New Hampshire does not decarbonize its grid, and Including New Hampshire shows the capacity needed if New Hampshire also pursues decarbonization of its economy.

jected peak system demand from 57 GW to 52.5 GW, and the continued use of natural gas provides critical dispatchable capacity for the system, allowing it to perform better during periods of low wind and solar output.

Our initial analysis assumed that New Hampshire would add new natural gas capacity to meet rising demand for electricity. Under a scenario where New Hampshire also pursues decarbonization of its economy, demand will peak at 57 GW, and these new natural gas facilities would not be constructed.

As a result, the installed capacity on the ISO-NE system would need to increase by 15 GW to meet the new peak electricity demand and replace the lost generation of potential new natural gas power plants. This would require an additional 4 GW of offshore wind capacity, 4.6 GW of onshore wind capacity, 3.2 GW of solar capacity, and 3.4 GW of battery storage. (See Figure 18)

Constructing and operating these additional facilities, and paying the additional taxes, transmission expenses and generator profits would cost $871 billion through 2050, meaning New Hampshire's current energy policies would save all New Englanders $56.5 billion during the time period studied.


NATURAL GAS

SECTION VI

The Levelized Cost of Energy for Different Generating Resources

Almost all studies that examine the cost of renewable energy use a methodology called the Levelized Cost of Energy (LCOE) to assess the cost of offshore wind, onshore wind and solar compared to different technologies.[71] LCOE estimates reflect the cost of generating electricity from different types of power plants, on a per-unit of electricity basis (generally megawatt hours), over an assumed lifetime and quantity of electricity generated by the plant.

In other words, LCOE estimates are essentially like calculating the cost of your car on a per-mile-driven basis after accounting for expenses like initial capital investment, loan and insurance payments, fuel costs and maintenance.

Wind and solar advocates often misquote LCOE estimates from Lazard, a financial advisory firm, or the US Energy Information Administration (EIA) to claim that wind and solar are now lower cost than other sources of energy. However, Lazard and EIA show the cost of operating a single wind or solar facility at its maximum reasonable output; they do not convey the cost of reliably operating an entire electricity system with high penetrations of wind and solar, which costs exponentially more.[72]

For example, Lazard and EIA do not account for the expenses incurred to build new transmission lines, additional taxes, or the cost of providing backup electricity with battery storage when the wind is not blowing or the sun is not shining, referred to as a battery storage cost in this report. [73]

Even more importantly, the LCOE estimates generated by Lazard and EIA do not account for the massive overbuilding and curtailment that must occur to ensure that grids with high reliance on wind, solar and battery storage meet electricity demand.[74]

It is important to understand that the costs associated with load balancing, overbuilding and curtailment increase dramatically because the amount of wind, solar and battery storage must be "overbuilt" to account for the intermittency of wind and solar, which is why the New England Decarbonization Plans require an installed capacity of 225 GW to meet the projected peak demand of 52.5 GW.

Our model accounts for all these additional expenses and attributes them to the cost of wind and solar to get an 'All-In' LCOE value for these energy sources. Our 'All-In' LCOE represents the cost of delivering the same reliability value of other generating technologies, allowing for an

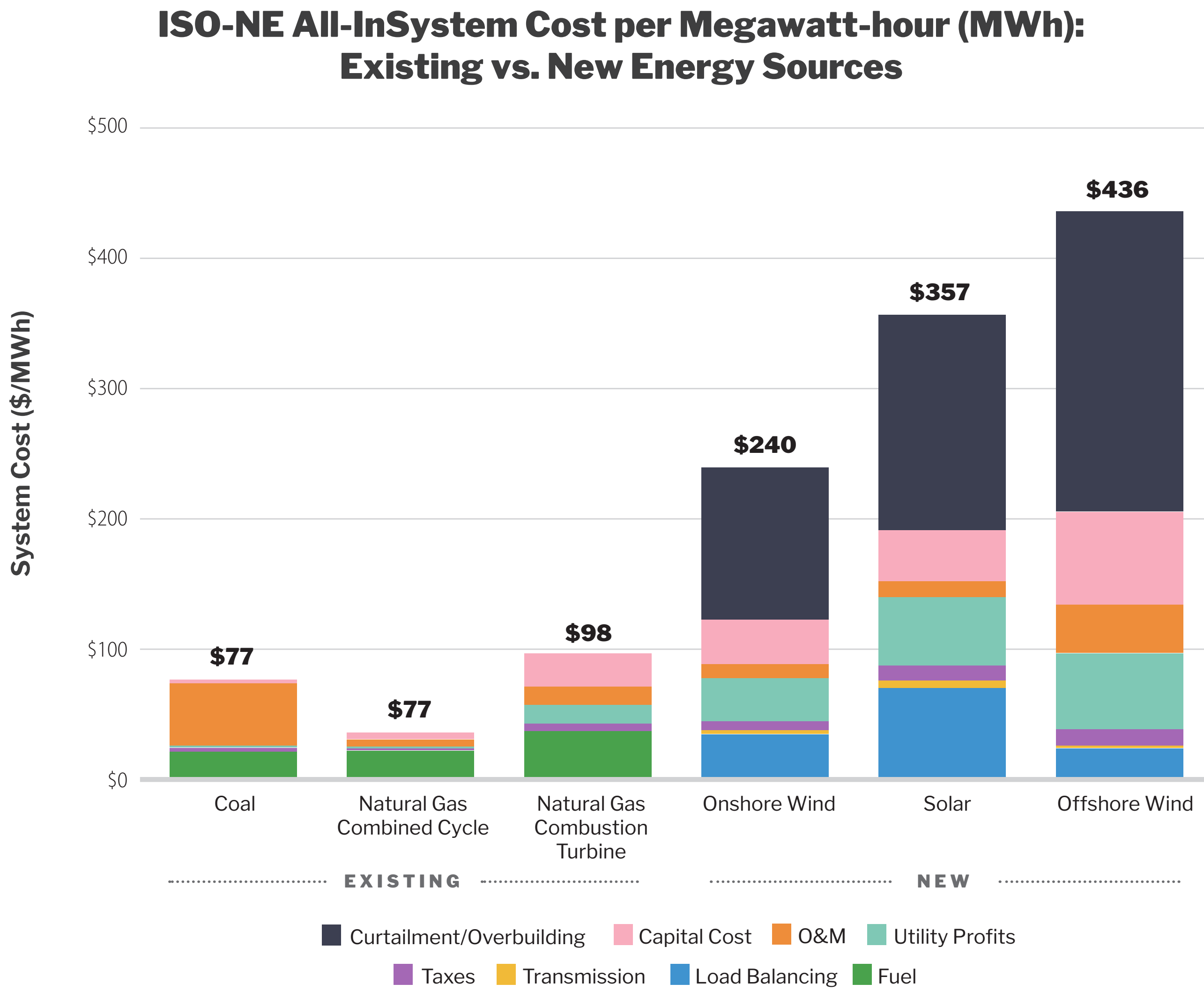


FIGURE 19. New offshore wind facilities are the most expensive form of new electricity generation built under the New England Decarbonization Plans. Once costs such as state taxes, transmission, utility returns, battery storage, and overbuilding and curtailment, are accounted for new offshore wind costs $436 per MWh, onshore wind costs $240 per MWh, and new solar costs $357 per MWh.

apples-to-apples comparison of the cost of reliably meeting electricity demand with existing nuclear, natural gas and coal plants operating in New England, with new plants built under the New England Decarbonization Plans.

The cost of existing natural gas generators was estimated using historical construction costs based on the average plant life of each energy source and current variable and fixed operation and maintenance (O&M)

expenses obtained from the U.S. Energy Information Administration.[75] This method was chosen in the absence of relevant FERC Form 1 filings in the ISO-NE region and similar data for Independent Power Producers (IPP). All other existing generators were estimated using the U.S. average cost for power plants in FERC Form 1 filings.

Under the New England Decarbonization Plans, these low-cost, reliable natural gas plants would be largely replaced with offshore wind, onshore wind, solar, and battery storage, by 2050. Figure 19 shows the 'All-In' LCOE of new offshore wind, onshore wind, and solar reaches approximately $436, $240 and $357 per MWh, respectively, in 2050.

Because curtailment rates reach 64 percent by 2050, overbuilding and curtailment costs are the primary drivers of wind and solar due to the need to build nearly 6.4 times more capacity than would be needed to meet peak demand with dispatchable power plants.[76] As a result, the cost of battery storage, overbuilding and curtailing in Figure 19 can be thought of as a levelized cost of intermittency, or unreliability.

Costs are higher for offshore wind, onshore wind and solar facilities because grids powered with large concentrations of intermittent wind and solar resources require greater total capacity and transmission to meet electricity demand than systems consisting largely of dispatchable power systems such as traditional fossil fuel and nuclear plants.

SECTION VII

Implications for Reliability

Reliability is the most crucial function of the electric grid. Our lives have never been more dependent upon electronic devices, and it is highly unlikely that we will be less dependent upon them in the future.

ISO-NE's *2050 Transmission Study*, which found that the modeled resource mix in the All Options Pathway for electricity demand, when combined with the resource availability assumptions made by the ISO, were "insufficient to meet the snapshot loads for the Summer Evening and Winter Evening Peaks of 2035, 2040 and 2050. The largest observed shortfall was roughly 12,000 MW in the 2050 57 GW Winter Peak snapshot."

Thus, within 11 years, ISO-NE may be unable to coordinate electricity to power the region. How bad could it get? If each of the New England states adheres to the same renewable-intensive path, a blackout scenario could be dire indeed.

The New England Decarbonization Plans will seriously undermine the reliability of the electric grid by making it more dependent on fluctuations in the weather. This dependency will end in blackouts. In contrast, the current grid maintains the reliability of New England's electric grid at a much lower cost.

Our modeling determined the amount of offshore wind, onshore wind, solar and battery storage capacity needed for the New England Decarbonization Plans by using hourly electricity demand data based on ISO-NE projections for 2050 demand, and real-world data from the U.S. Energy Information Administration for onshore wind and solar generation output in 2023, and offshore wind output from ISO-NE variable energy resource data for the year 2019.

With these inputs, our model determined that the 66 GW of offshore wind, 19.2 GW of onshore wind, 68.4 GW of solar, 43 GW of four-hour battery storage, along with the existing nuclear capacity of 3,356 MW, 4,400 MW of new natural gas capacity built in New Hampshire, and existing natural gas capacity of 16 GW, and 6,675 MW of electricity imports from neighboring regions, would provide enough electricity to meet demand for every hour of the year in 2023.

Figure 20 shows electricity demand and supply by type for a hypothetical period in the future stretching from December 14, 2050, to December 18, 2050. As you can see, offshore wind, onshore wind, solar, battery storage and New England's existing nuclear and natural gas power plants are able to provide enough electricity to meet demand, shown in the black line.

ISO-NE Hourly Electricity Supply During Peak Demand in 2050 Using 2019 Wind and Solar Output

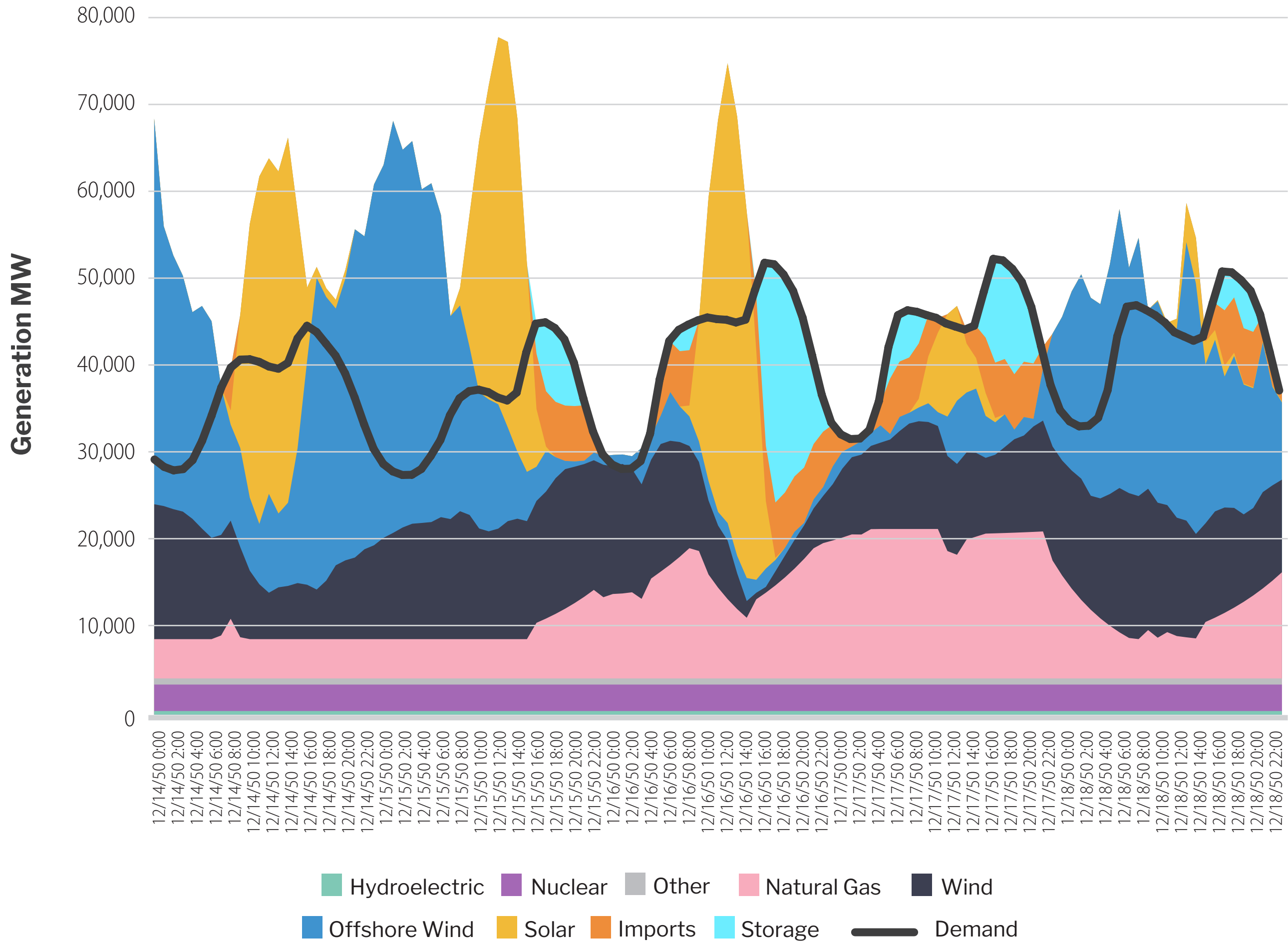


FIGURE 20. Offshore wind, onshore wind, solar, battery storage, nuclear and natural gas are able to meet electricity demand for every hour of the year 2023.

While our model shows there is enough electricity to meet demand for every hour of 2023, it is important to remember that this conclusion is based on just one year's worth of weather-driven wind and solar generation data.[77] Given that wind and solar generation is subject to weather patterns, it is important to evaluate whether changes in the weather would result in a situation where electricity supply could not meet demand — a capacity shortfall — resulting in rolling blackouts.

ISO-NE Hourly Electricity Supply During Peak Demand in 2050 Using 2019 Wind and Solar Output

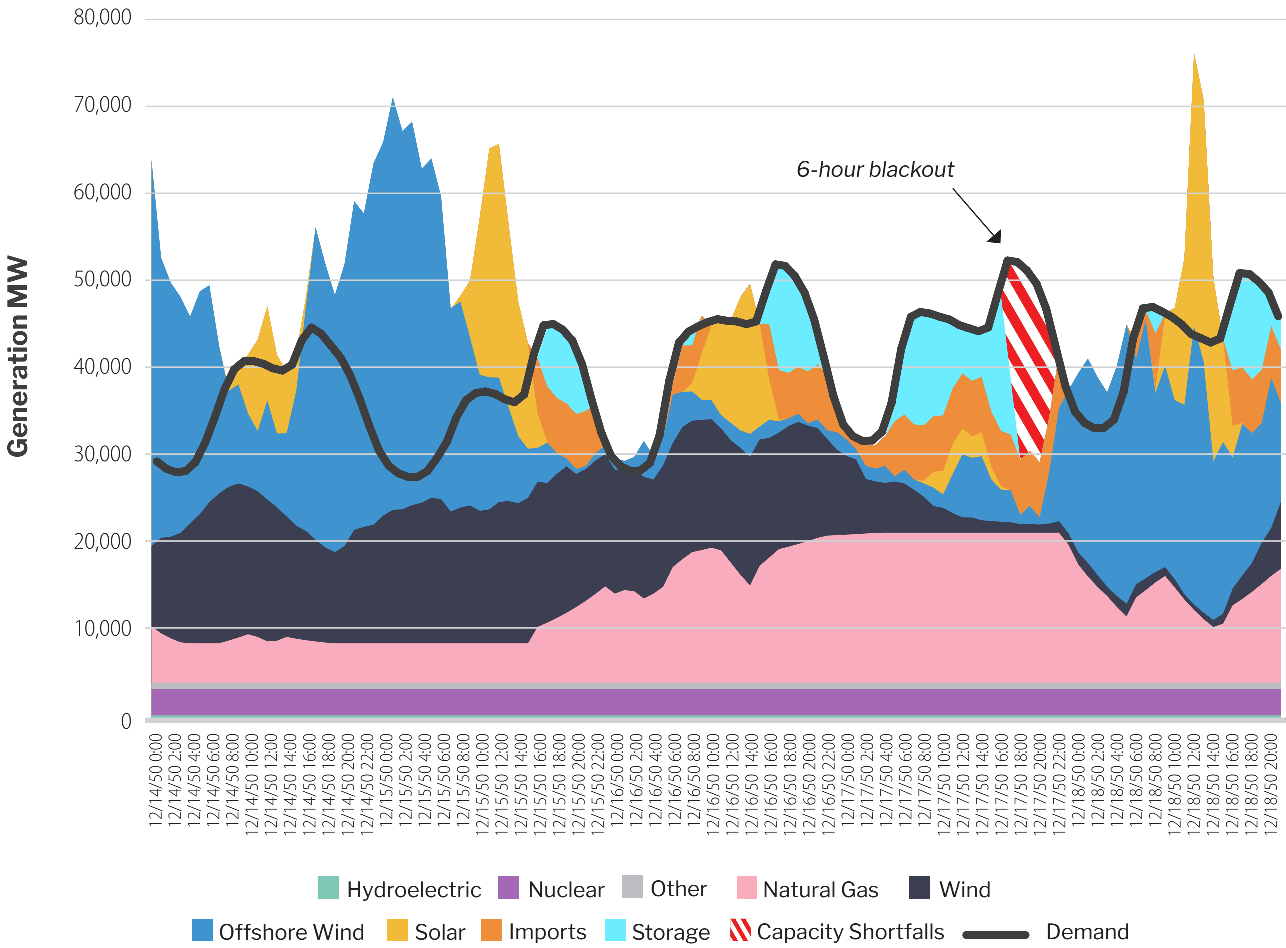


FIGURE 21. The resources on the ISO-NE under the New England Decarbonization Plans are unable to meet electricity demand for every hour of the year, resulting in a 6-hour capacity shortfall in December.

To evaluate the impact of annual changes in wind and solar generation on the reliability of the grid, AOER obtained capacity factors for offshore wind, onshore wind and solar from 2019 through 2022 to see if the amount of installed wind, solar, battery storage, nuclear and natural gas capacity in the New England Decarbonization Plans would be enough to meet electricity demand at all hours of every year, regardless of changes in the weather. The short answer: it would not.

The Reliability of the New England Decarbonization Plans with 2019 Weather

Using 2019 wind and solar generation data from ISO-NE, AOER determined that there would be six total hours of capacity shortfalls throughout the year, with a maximum capacity shortfall of more than 22,500 MW, which is near the current peak of the ISO-NE system.

Figure 21 shows electricity demand and supply during the same hypothetical period in the future stretching from December 14, 2050, to December 18, 2050. As you can see, offshore wind, onshore wind, solar, battery storage and New England's existing nuclear and natural gas power plants are unable to provide enough electricity to meet demand, shown in the black line, resulting in a six-hour blackout.

The capacity shortfall on December 17, 2050, is caused by low wind and solar output and insufficient battery storage capacity to store excess wind generation from previous days — even with more than 170,000 MWh of storage available. During this period, solar capacity factors were just one percent, onshore wind capacity factors were eight percent and offshore wind capacity factors were five percent.

The size of the shortfall is significant, with a maximum shortfall of 22,528 MW occurring at 6:00 p.m. on December 17, which is nearly the current winter peak observed on the ISO-NE system.

These findings are consistent with the ISO-NE *2050 Transmission Study*, which found that the modeled resource mix in the All Options Pathway, when combined with the resource availability assumptions made by the ISO, were "insufficient to meet the snapshot loads for the Summer Evening and Winter Evening Peaks of 2035, 2040 and 2050. The largest observed shortfall was roughly 12,000 MW in the 2050 57 GW Winter Peak snapshot."[78]

Import Uncertainty

A key component of the ISO-NE decarbonization strategy consists of importing electricity from New York and Canada during periods of high demand and low wind and solar output. Our analysis is conservative because it assumes all 6,675 MW of the existing and planned transmission projects to import electricity into New England are firm, meaning they can deliver their full rated capacity at any point when needed.

However, this strategy is fraught with considerable uncertainty because New York — which is also highly dependent upon natural gas — is also seeking to decarbonize its electricity supply using intermittent resources while achieving high levels of electrification in the transportation and home heating sectors.[79,80]

Due to their close proximity, this could mean that New York will experience high demand at a time when its wind and solar resources, especially its offshore wind installations located off the coast of New England, are not producing enough electricity to satisfy its own internal demand, let alone allow for exports to New England.[81]

Canadian imports, meanwhile, could also be subject to interruption. Hydro Quebec (HQ) is the largest exporter into the ISO-NE region, sending significant amounts of power to the New England states in the summertime.[82] This is possible because Quebec, with 71.4 percent of households using electric heating and heat pumps in 2021, is a winter peaking system, and ISO-NE is currently a summer peaking system.[83]

This efficient partnership will face challenges in the years ahead as ISO-NE becomes a winter peaking system.

In February of 2023, a cold snap enveloped Quebec, causing electricity demand to reach new all-time highs. During this period, HQ demand reached 42,472 MW, outstripping the installed capacity of 37,200 MW on the HQ system.[84] As a result, HQ had no power to send to New England. In fact, it was importing power from neighboring regions, including New York, Ontario and ISO-NE.

Increasing transmission capabilities with Hydro Quebec and New Brunswick greatly diminish the chances of rolling blackouts in ISO-NE in the spring, fall and summer months, but the potential for region-wide cold spells that cause electricity demand to surge will present clear and present dangers to grid reliability.

To better understand these future risks, additional study of hourly electricity consumption that reflect observed regional weather patterns will be necessary to create a more holistic picture of regional electricity demand and its impact on import availability in the future.

SECTION VIII

Emissions Reductions

When evaluating energy policies aimed at reducing greenhouse gas emissions, it is important to weigh the cost of reducing emissions against the expected benefits of doing so. If the costs of reducing emissions exceed the expected benefits, the policy does not make sense to enact.

To conduct this cost benefit analysis, policymakers often use a tool called the Social Cost of Carbon (SCC) to estimate the economic costs, or damages, of emitting one additional ton of carbon dioxide into the atmosphere.[85] While the SCC has serious shortcomings, it can help illustrate when the costs of a proposed policy obviously outweigh the benefits.[86]

Figure 22 shows the annual decline in carbon dioxide emissions from the power sector under the New England Decarbonization Plans.

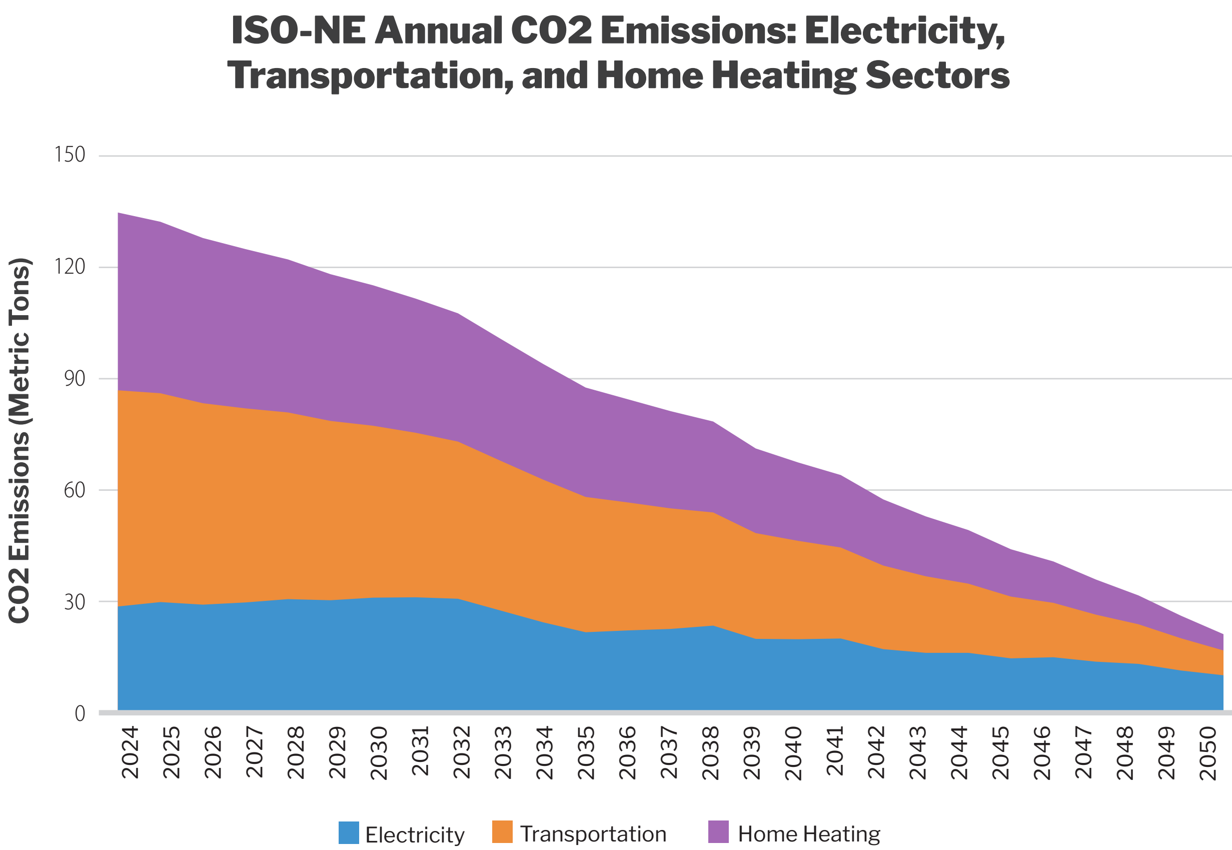


FIGURE 22. Under the energy policies of the New England states, carbon dioxide emissions would drop 84 percent from 2022 levels to 21.1 million metric tons by 2050.

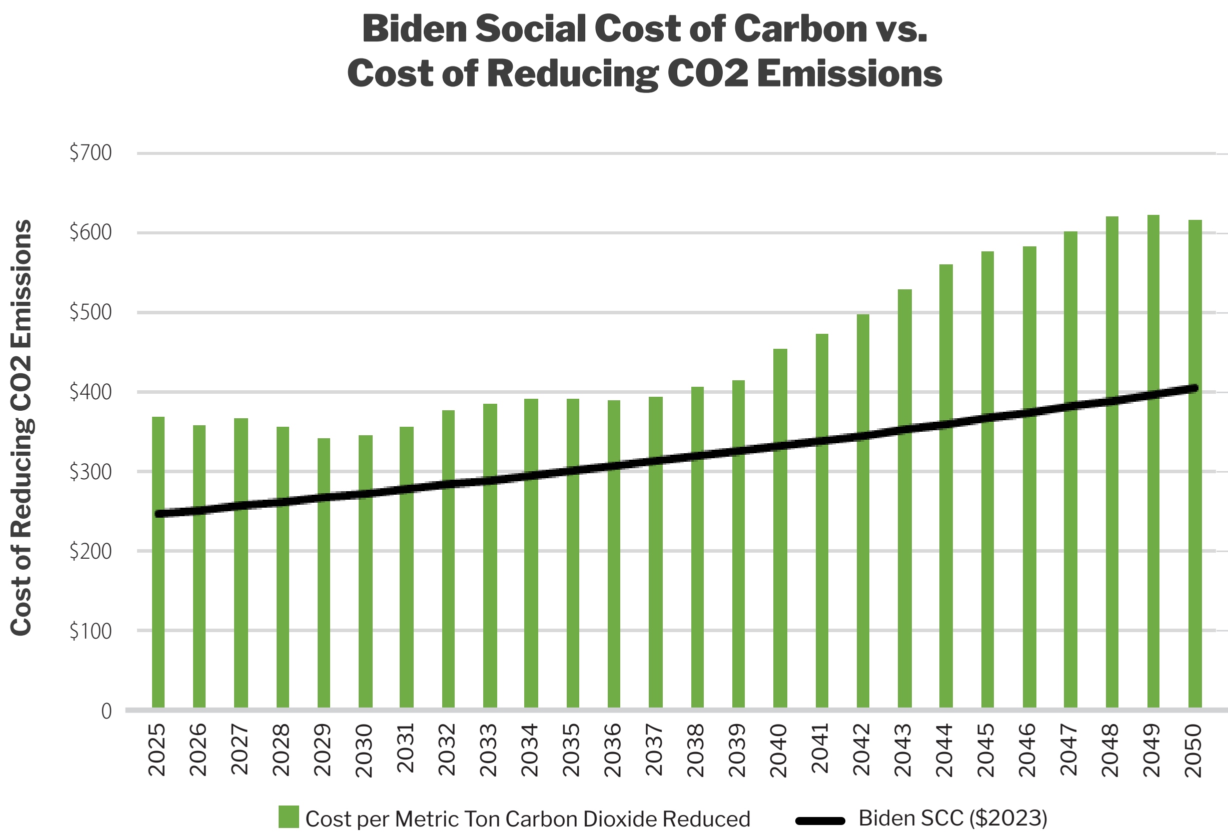


FIGURE 23. The cost of reducing emissions under the New England Decarbonization Plans vastly exceed the Biden SCC estimates in every year studied.

Figure 23 shows the cost of reducing each ton of carbon dioxide each year under the New England Decarbonization Plans and compares it to the SCC estimates established by the Biden administration.

Figure 23 shows that the cost of reducing carbon dioxide emissions in the New England Decarbonization Plans exceeds the Biden administration SCC estimates for every single year. This means the cost of reducing carbon dioxide emissions under these plans exceeds the benefits of doing so. In short, the New England states are imposing a net harm on their economies after accounting for the financial impacts of climate change.

SECTION IX

ESG's Impact on New England Utility Bills and Pension Funds

The Paris Climate Accords bound national governments to emission reduction targets that would help transition the global economy to ensure annual emissions are balanced with nature's annual sequestration capacity — a net-zero state. The European Union, Great Britian and Canada have foisted carbon taxes and emissions quotas on their populations to achieve their net-zero emission reduction obligations. These policies have forced manufacturers, refiners, businesses and farms to close.[87]

To date, while American industries have avoided the most heavy-handed types of climate regulation, activists, companies and state governments have been stepping up the pressure to adopt Environmental Social Governance (ESG) internal policies, which will raise heating costs for consumers and weaken retirement security for state employees.

BlackRock and other climate-focused financial institutions have pressured companies to adopt ESG reporting metrics aiming to harmonize their operations with America's Paris Climate Accord net-zero pledge. In 2021, over 95 percent of large, publicly-traded companies were voluntarily reporting their emissions through ESG reports.[88] These reports contain ESG scores logging total emissions. Low ESG scores brand companies and businesses with climate risk. Activist pension fund managers will avoid investing in industries that produce or heavily utilize fossil fuels. More worryingly, states are beginning to require public pension funds to weigh climate risk and divest from industries with low ESG scores.

Looking to avoid the criticism associated with low ESG scores, New England's major Investor-owned utilities (IOUs) are considering blending hydrogen into natural gas infrastructure to reduce emissions from their residential and commercial natural gas services. Blending hydrogen would render much of the existing natural gas infrastructure obsolete and result in costly replacements to existing infrastructure. By 2050, the natural gas service charge would increase up to $1,588.82 per year for the average New England resident.

State and local pension fund managers are seeing increased pressure from state and municipal politicians to adopt ESG metrics and completely divest from fossil fuel companies. Obliging these demands for arbitrary investment constraints puts pension funds at risk of being unable to make monthly payments to retirees. The decreased diversity exposes the fund to more volatile investments. Which if sold for a loss to meet these obligations, reduces the value of the fund. Maine's pension fund could be losing more than half a billion in cash dividends paid by their investments in fossil fuel companies. If Maine's pension fund serves as a bellwether for other retirement programs, then New England's retirees are facing billions of losses and the potential decline in their pension funds solvency.

ESG Encouraging Premature Regional Hydrogen Rollout

Responding to demands from ESG investors, state politicians and regulators to reduce their greenhouse gas emissions, utility companies across New England such as National Grid, Eversource and Constellation, are considering blending hydrogen with natural gas to reduce emissions from residential service and power plants.[89] Blending hydrogen into the system would ostensibly reduce CO2 emissions while simultaneously preventing billions in stranded assets. However, preparing the natural gas distribution system for hydrogen blending would cost billions of dollars as polyethylene pipes would need to be upgraded to more expensive and inferior steel pipes. The average New England resident could expect service charges to increase between $397 and $1,588 per year.

SEE FIGURE 24. New England Natural Gas Customers[90]

More than 3.1 million New Englanders rely on natural gas to power home appliances and heat their homes in the winter. A significant portion of New England's natural gas infrastructure was laid in the late 19th and early 20th centuries. These pipes carried coal- and oil-manufactured gas to illuminate city streets and businesses in Boston, Hartford, Providence and dozens of other municipalities across New England.[91] When natural gas arrived in the region via new pipelines in the 1950s, utilities pumped it through the existing black-iron pipes.[92]

These century old pipes are causing problems for the New Englanders who depend on them for natural gas. In 2014, it was estimated that 17

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Total
Residential	588,711	35,593	1,790,157	114,313	247,508	48,791	2,825,073
Commercial	62,951	12,524	164,459	19,657	24,636	6,216	290,443
Industrial	2822	171	11,823	191	282	14	15,303

FIGURE 24. New England Natural Gas Customers shows the distribution of New England's 3.1 million Natural Gas customers broken down by classification.

percent of Massachusetts' pipeline network was nearing the end of its useful life. In 2017, Connecticut's corroded pipelines leaked a significant quantity of methane across the state.[93] Most, if not all, of the century old pipes would fail the International Fuel Gas Code (IFGC) standards, which forbid using cast iron pipe, valves, and fittings in systems transporting gaseous hydrogen.[94]

High density polyethylene (HDPE) piping has been the primary choice for utilities replacing cast iron and steel mains since the 1960s. HDPE service mains last longer and offered superior gas retention than metal pipes.[95] Most importantly, polyethylene pipes are typically 50 to 90 percent cheaper than steel pipelines.[96] Funding made available through the federal 2021 Bipartisan Infrastructure Deal has allowed many local distribution companies (LDCs) to replace their aged pipes with HDPE pipes.[97]

Unfortunately, HDPE pipelines are likely unsuitable for transporting blended or gaseous hydrogen. Studies have shown when hydrogen is blended into natural gas, HDPE pipelines leak 1.7 to 5 times more hydrogen than steel piping. Under lab conditions, natural gas leaks from HDPE pipes carrying blending hydrogen doubled. While these losses are economically negligible for the utility, the impact of these leaks on a pipeline's structural integrity and lifespan are unknown. NREL's survey of scientific literature on hydrogen blending concluded that further research needs to determine the impact on pipeline's "physical properties, such as density and degree of crystallinity… [and] the mechanical performance… lifetime of polymer pipes and pipe joints… and effects of hydrogen on specific resin formulations."[98]

If pipelines are weakened by hydrogen blending, the useful life of the pipelines will be reduced and create safety hazards throughout the network. Given the uncertainty of hydrogen's impact on HDPE pipes, utilities would need to replace all HDPE pipelines with costlier and inferior steel plumbing.

AOER estimated the cost of upgrading and replacing 25, 50, 75 and 100 percent of New England's gas transmission network. Given that HDPE pipes comprise the majority of service mains built and a significant portion of vintage infrastructure still in service, the estimated cost of rolling out hydrogen blending would likely fall in the higher end of these estimates.

SEE FIGURE 25. New England Gas Infrastructure[99]

New England has 38,144 miles of natural gas distribution and 26,924 miles of residential service lines spread over six states. Pipelines in Massachusetts and Connecticut account for 77 percent of total pipelines in the

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Total
Interstate Transmission pipelines	591	510	1,133	248	95	74	2651
Distribution mains	7,984	1070	21,600	1,070	3,210	3,210	38,144
Service Mains	5,964	494	15,100	494	2,436	2,436	26,924

FIGURE 25. New England Gas Infrastructure shows the milage of pipeline contained in each state.

region. These pipelines typically range from two to 16 inches wide.[100]

To estimate the cost of replacing natural gas distribution lines, AOER examined the cost per mile of several natural gas distribution mains in New England and compared them to estimates from contractors and other states. Where applicable, these numbers were adjusted for inflation using the producer price index for finished goods.[101]

The survey of natural gas pipeline expansions and replacement projects produced an average per mile cost of $1.851 million/mile (mm/m).[102] Costs ranged from $1,100,000 up to $4,565,805 mm/m. The significant variation was due to the pipeline diameter and materials used.

The estimates for New England projects were in line with the estimates observed. RSP Gas Piping, a company based in Arizona, estimated costs at $1.9 mm/m in 2017 ($2.351 mm/m in 2023).[103] A 2017 report, Natural Gas Infrastructure Modernization Programs at Local Distribution Companies, produced by the U.S. Department of Energy found the cost of replacing natural gas pipelines ranged from one to five million reported in 2017 dollars.[104] Adjusted for inflation, these costs are $1.9 million up to $9.9 million. The higher end of this estimate likely reflects the costs associated with improving natural gas distribution infrastructure within cities. In 2017, New York City had the highest per mile cost of replacing natural gas infrastructure ranging from two to eight million.[105] Adjusted for inflation, these costs are $2.5-$10.2 million. A 2023 report produced by the Building Decarbonization Coalition, a coalition advocating for green energy in buildings, estimated installation cost of natural gas pipeline at $3 mm/m. Salvage costs, taxes and regulated rate of return raised total costs up to $6,177,000 per mile.[106]

The cost of replacing natural gas pipelines in Boston, Hartford and Providence are likely to be higher than replacing aging distribution mains in smaller towns. For this analysis, we present a low-cost estimate assuming an average cost of $1.975 mm/m.

% mains replaced	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Total
25%	$3,943	$528	$10,668	$528	$1,585	$1,585	$18,839
50%	$7,886	$1,057	$21,336	$1,057	$3,171	$3,171	$37,678
75%	$11,830	$1,585	$32,004	$1,585	$4,756	$4,756	$56,517
100%	$15,773	$2,114	$42,672	$2,114	$6,342	$6,342	$75,356

FIGURE 26. Cost of Replacing Distribution (in millions) mains shows the cost in millions of preparing New England's natural gas transportation network for hydrogen.

% mains replaced	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Total
25%	$71	$6	$179	$6	$29	$29	$320
50%	$142	$12	$359	$12	$58	$58	$640
75%	$213	$18	$538	$18	$87	$87	$960
100%	$283	$23	$718	$23	$116	$116	$1,279

FIGURE 27. Material Cost of Replacing Residential Service Lines in New England (in millions) estimates the cost of replacing residential natural gas service lines in New England. Costs assume $47,520 per linear mile of galvanized steel pipe. The percentage column provides the assumed scenarios that 10, 50 and 100 percent of residential gas lines would need to be replaced to accommodate hydrogen-blending.

SEE FIGURE 26. Cost of Replacing Distribution Mains

Total regional cost of replacing distribution mains in New England ranged from $18 – $75 billion.

Residential service mains are the remaining natural gas pipelines. These pipelines range from 0.5 up to 1.5 inches[107] and carry natural gas from the distribution mains into homes and businesses. Using a price of $9 per linear foot,[108] AOER estimates that replacing a mile worth of pipeline would cost $47,520 per linear mile, excluding labor and other materials. The total cost of replacing residential service lines in New England would range from $320 million up to $1.2 billion in pipeline materials alone.

SEE FIGURE 27. Cost of Replacing Residential Service Lines in New England

Labor costs were excluded from the estimate given the lack of available data. A user on City-data.com reported National Grid would lay 100

% mains replaced	Natural Gas Distribution and Service Main Replacement Costs (in Millions)						
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Total
25%	$4,014	$534	$10,847	$534	$1,614	$1,614	$19,159
50%	$8,028	$1,069	$21,695	$1,069	$3,229	$3,229	$38,318
75%	$12,042	$1,603	$32,542	$1,603	$4,843	$4,843	$57,477
100%	$16,056	$2,137	$43,390	$2,137	$6,457	$6,457	$76,635

FIGURE 28. Hydrogen Cost Total presents the total cost of upgrading New England's distribution and residential service mains to accommodate hydrogen blended natural gas by state. The total cost of upgrading the system to carry hydrogen-blended natural gas ranges from $19 – $76 billion.

feet of pipe at no charge and then charge $80 every foot thereafter.[109] CenterPoint Energy, a utility based in Texas, offered a similar deal in 2015, offering to install 75 feet complimentary and then charging an additional $80 per foot.[110] Assuming galvanized steel pipe costing roughly $10 per foot, the inferred labor price per foot is $70 per foot. At $70 per foot, this would increase costs by $369,000 per mile, and increase total regional costs up to $9.9 billion.

SEE FIGURES 28 & 29.

The total cost of preparing New England's natural gas distribution network for blended hydrogen ranges from $19 – $76 billion. The amount that would be carried by ratepayers varies by state and the number of available customers. Ratepayers in Vermont and Maine would see the largest increase in their annual base-rate utility bills due to their relatively small number of natural gas customers. On average, base rates for natural gas would need to rise between $397 – $1,588 per year dependent on the amount of infrastructure needing replacement.

While regulators and politicians have advocated for green hydrogen for years, ESG ratings are providing financial incentive for industries to make good on the state-mandated regulations. The push for utilities to adopt hydrogen is just one of the many green technologies IOUs are banking on to lower their utility bills. Furthermore, an IOUs ability to secure a regulated seven percent rate of return on installing infrastructure ensures that they will profit from the replacements, while ratepayers would be the ones picking up the largest share of the bill.

% mains replaced	Customers Share by State					
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont
25%	$6,133.21	$11,065.55	$5,516.29	$3,982.78	$5,925.77	$29,340.31
50%	$12,266.41	$22,131.09	$11,032.59	$7,965.55	$11,851.53	$58,680.61
75%	$18,399.62	$33,196.64	$16,548.88	$11,948.33	$17,777.30	$88,020.92
100%	$24,532.83	$44,262.19	$22,065.17	$15,931.10	$23,703.07	$117,361.22
	Annualized Increase in Service Charge					
25%	$235.89	$425.60	$212.17	$153.18	$227.91	$1,128.47
50%	$471.79	$851.20	$424.33	$306.37	$455.83	$2,256.95
75%	$707.68	$1,276.79	$636.50	$459.55	$683.74	$3,385.42
100%	$943.57	$1,702.39	$848.66	$612.73	$911.66	$4,513.89

FIGURE 29: Customer share of Hydrogen Cost shows the amount ratepayers share of the bill for upgrading the natural gas network to carry hydrogen-blended natural gas. Annualized costs assume that utilities will want to achieve a hydrogen-ready network by 2050 to maintain alignment with Paris Climate Accord's net-zero target.

State and Local ESG Policy Impact on Pension Funds

Policies aiming to establish ESG investment metrics and ordering pension funds to divest from fossil fuel companies are becoming more common at the local and state levels. ESG policies in New England aim to establish ESG metrics and require pension fund managers to divest from fossil fuel companies. These policies impose arbitrary restrictions on fiduciaries entrusted with state pension funds.

In addition, several unique policies in the region have emerged in the states that make it harder for fossil fuel companies to justify investing in the region. In 2023, Connecticut introduced legislation imposing a five percent surcharge on all insurance policies issued to fossil fuel producing and transporting companies. While the original bill died, it has been reintroduced in a larger omnibus bill that implements the governor's budget recommendations, which is more likely to pass. Though the intended target of the bill is major fossil fuel companies, local distributors of heating oil and other natural gas liquid fuels will inadvertently be harmed by this bill. Meanwhile, Vermont's Climate Change Cost Recovery Act passed in May 2024 will appraise the damages caused by storms and then send an invoice to fossil fuel companies.

Figure 30 provides a list of and summarizes ESG bills enrolled into New England's legislatures. Bills that die in committee are typically revived in subsequent sessions. For example, HB 2515, which would require Massachusetts public retirement system to divest from fossil fuel companies has been reintroduced in every legislative session since the assembly of the 188th General Court. In Connecticut, S.B. 11 contains provisions laid out in the dead S.B. 1115. Bills that are currently stuck in committee and are likely to die this session have been included to make tracking their future iterations easier.

For this section, AOER examined the impact that fossil fuel divestment and similar ESG rules can theoretically have on a pension fund. These policies are prompting a myopic withdrawal from the energy industry whose dividends support fund managers who require cash on hand to make monthly payments to pensioners. Using data obtained from Maine's 2023 fossil fuel divestment report, AOER found that Maine's pension fund may lose over $664 million in cash dividends paid by fossil fuel companies over the next 10 years.

SEE FIGURE 30. ESG Laws in New England[111]

ESG Metrics and Fossil Fuel Divestment Policies

ESG metrics and fossil fuel divestment policies are functionally the same. ESG metrics prioritize the net-zero objectives of the Paris Climate Accords over financial returns and would require fiduciaries to divest from companies with low ESG scores. With the average fossil-fuel focused company earning a high ESG score, fiduciaries bound to ESG metrics will be all but required to eschew investing in fossil fuel companies.[112]

Fossil fuel divestment policies have popped up throughout New England over the last decade. Between 2014 and 2024, several municipalities have required their pension funds to dispense fossil fuel assets.[113] In June 2021, Maine became the first state to pass a bill requiring state pension funds to divest from fossil-fuel companies.[114] Only a few months later, on Nov. 22, 2021 Boston Mayor Michelle Wu signed an ordinance, which she advocated for while serving as a councilwoman, requiring the city pensions to divest from fossil fuel companies.[115] Earlier that year, in June 2021, Maine became the first state to pass a bill requiring state pension funds to divest from fossil-fuel companies.[116] In June 2024, Vermont became the second state in New England to adopt a fossil fuel divestment act.

In June 2024, Rhode Island successfully passed a bill binding fiduciaries managing state pension funds to government set ESG metrics. While Massachusetts and Connecticut have had ESG metric bills introduced into their legislatures, neither has passed it into law. The Massachusetts

	Bills/Public Law	Description	Date Introduced/ Signed
Massachusetts	HB 4819 An Act to mandate the review of climate risk in order to protect public pension beneficiaries and taxpayers	Pending Legislation: HB 4819 directs fiduciaries to consider "the protection of future social and environmental benefits (based on HB 2504)	8-Jul-24
Massachusetts	SB 1723 An Act Authorizing Independent Retirement Boards to Divest from Fossil Fuel Companies	Pending Legislation: SB 1723 & HB 2515 divests Public Funds from Oil and Gas Companies	19-Jan-23
Massachusetts	SB 1644 An Act relative to Pensions, Fiduciary Standards, and Sustainable Investment)	Pending Legislation: SB 1644 directs fiduciaries to consider "the protection of future social and environmental benefits"	20-Jan-23
Massachusetts	HB 2504 An Act to Mandate the Review of Climate Risk in order to Protect Public Pension Beneficiaries and Taxpayers	Revived Legislation: HB 2504 Requires pension funds to divest from "climate risk investments" by 2026	20-Jan-23
Massachusetts	SB 2610 An Act relative to pensions, fiduciary standards, and sustainable investing	Replaced Legislation: SB 1644 establishes ESG metrics, replaced by SB 2610 on February 8, 2024	20-Jan-23
Massachusetts	SB 1648 An Act relative to responsible corporate investments	Replaced Legislation: SB 1648 prevents state treasurer from investing retirement savings into states that have placed restrictions on ESG; Replaced by SB 2610	18-Jan-23
Connecticut	SB 11 An Act concerning Connecticut Resiliency Planning and Providing Municipal options for Climate Resilience	Pending Legislation: Implements the Governor's budget recommendations and revives SB 1115's surcharge on fossil fuels.	8-Feb-24
Connecticut	HB 6397 An Act Concerning Zero-Carbon Emissions & An Act Concerning the Divestment of State Funds from Fossil Fuel Corporations	Dead Legislation: HB 6397 & 6348 would have directed the State Treasurer to divest public pension funds from fossil fuels	20-Jan-23
Connecticut	SB 1115 An Act Establishing a Surcharge on Insurance Companies In this State That Underwrite Fossil Fuel Companies	Dead Legislation: SB 1115 would have added a 5% tax onto insurance premiums paid by fossil-fuel companies; This surcharge was revived in pending SB 11 (Sec. 35)	23-Feb-23
Connecticut	SB 42 An Act Concerning the Climate Sustainability scores of Companies Invested in by the State Treasurer	Dead Legislation: SB 42 would have directed State Treasurer to establish ESG metrics to ensure pensions are invested in accordance with state climate goals	13-Feb-23
Maine	HP 65/LD 99	Public Law: HP 65/LD 99 directs Maine Pension funds to divest from fossil-fuel companies	16-Jun-21
Vermont	Act 122: Climate Change Cost Recovery Act	Public Law: SB 259 Invoices fossil-fuel companies for climate damage	30-May-24
Vermont	SB 42 An act relating to divestment of State Pension Funds of investments in the fossil fuel industry	Pending Legislation: SB 42/HB 197 directs Pension Fund to divest from fossil fuels	26-Jan-23
Rhode Island	SB 7127 An Act Relating to Public Finance - Rhode Island Retirement Savings Program Act	Public Law: HB 7127 & SB 2045 set ESG metrics for state pensions	26-Jun-24

FIGURE 30: ESG Laws in New England show recently considered ESG bills and public laws across New England.

Pension Reserves Investment Management Board (MassPRIM) in December 2022 established an ESG committee to help implement ESG framework for guiding investment decisions.[117] In 2023, the committee's name was changed to the Stewardship and Sustainability Committee.[118] Despite the name change, the mission of the committee remains unaltered. Even if bills fail to pass the legislature, climate-conscious bureaucrats are finding ways to inject ESG metrics and fossil fuel divestment requirements into state pension funds. These arbitrary restrictions on investment bar fund managers from investing in energy companies that serve a crucial role in maintaining pension fund solvency.

ESG's Impact on Pension Fund Energy Investment Strategy

When Democratic lawmakers met with Maine Public Employee Retirement System (MainePERS) President Rebecca Wyke in March 2024, the climate-conscious lawmakers sought answers for the pension fund's delayed divestment from fossil fuel companies.[119] Three years had elapsed since H.P. 65's passage and MainePERS still held a significant $1.2 billion in fossil fuel companies. The policymakers pointed to a scenario provided in MainePERS's 2023 divestment report which suggested that a fossil fuel divested portfolio returned 0.07 percent more than Maine's current fossil-fuel burdened portfolio when analyzed over a 25-year period.[120] A similar claim was made by the climate advocacy group Fossil Free California in June 2022, albeit with a significantly larger loss of value. Fossil Free California asserted that failing to divest from fossil fuels cost California's pension fund $17.4 billion in lost revenue between 2010 and 2019.[121]

These analyses are flawed, however, because they ignore the important role dividends from fossil fuel companies play in balancing a pension fund's monthly obligations to retirees and long-term returns on the funds. Fiduciaries use the dividends paid by fossil fuel companies and infrastructure to meet monthly payment obligations to pensioners without having to liquidate assets with high growth but low cash returns. Legislatively enforced ESG divestment policies prevent fund managers from fulfilling their duty by cutting a precious source of cashflow and narrowing fund managers investment prospects in the energy space.

Globally, pension funds hold $46 trillion in fossil fuel assets.[122] As of October 2023, California State Teachers' Retirement and Public Employees' Retirement Systems held over $9.4 billion in fossil fuel assets.[123] This included $3.9 billion in Exxon Mobil, Chevron, Shell, ConocoPhillips and British Petroleum stock, and billions more in other fossil fuel investments.[124]

Despite the backlash from climate activists, fiduciaries managing pension funds invest in fossil fuel companies for the large dividends relative to other sectors.[125] Out of 129 tracked industries, oil and natural gas midstream and exploration and production companies had the 8th and 14th highest average net profit margins.[126] These high net profit margins directly translate into ample cash dividends.

Fossil fuel companies' dividends per share can range from six to nine percent per year.[127] Between March 2020 and August 2024, State Street Global Advisors' Energy Select SPDR Fund (XLE) — an exchange traded fund (ETF) comprised of major oil and natural gas companies — dividend payments returned seven percent per year when annualized.[128] ETFs focused on owning natural gas infrastructure saw similar returns. Tortoise North American Pipeline Fund (TPYP), an ETF owning stock in North American pipeline operators, returned an annualized seven percent in cash dividends between March 2020 and August 2024.[129] While Vanguard's High Dividend Yield Index Fund does not yield seven percent, fossil energy companies make up 17.56 percent of its portfolio.[130]

Placing 8th out of 129 industries based on net profit margins, pipeline companies are renowned for their high dividends. Their small number of employees, established customer bases, and stable business model keep expenses low and allow profits to be distributed to stakeholders through high dividend payments. Many large pension funds are so prepossessed with the returns from pipeline companies' business model that fund managers frequently acquire direct stakes in pipeline infrastructure. In August 2021, the Ontario Teachers' Pension Fund owned more than $2 billion in natural gas pipeline infrastructure.[131] In March 2024, Blackrock, the world's largest pension fund manager, purchased the Portland Natural Gas Transmission System (PNGTS) pipeline from TC Energy.[132] Direct ownership over pipelines gives pension funds steady cashflow. Funds use revenue from natural gas infrastructure and cash dividends paid on fossil fuel company shares to pay pensioners without having to sell off stocks in high-growth sectors.

However, ESG policies are preventing fiduciaries from performing their duty by banning pension funds ownership of lucrative physical natural gas infrastructure and equities. To demonstrate the impact on pension funds, AOER estimated the average return from fossil fuel infrastructure based on returns to pipeline companies operating in New England and compared it to Maine's pension funds desired rate of return.

New England's three major pipeline service companies are Kinder Morgan, Enbridge and TC Energy. To demonstrate the impact of ESG policies on pension funds, AOER compared the returns from New England's pipeline companies to the performance of several leading renewable energy focused Exchange traded funds — TAN, QCLN, and ICLN. For further evidence of fossil fuel companies' high dividend yields, XLE and TPYP were included in the analysis.

FIGURE 31 shows the monthly change in stock prices for the renewable energy ETFs (TAN, QCLN, and ICLN), the pipeline ETFs (XLE and TPYP) and compares them to the stock prices for Kinder Morgan, Enbridge, and TC Energy from March 1, 2020, through July 1, 2024. The graph also incorporates cumulative dividend payments made to shareholders during this time and adds this value to the stock prices to show the total returns per share for each investment.

Initially, the renewable energy ETFs outperformed every fossil fuel asset by several orders of magnitude. But after peaking in January 2021, the prices of the stocks within the TAN, QCLN and ICLN ETFs declined 61 percent, 55 percent and 51 percent respectively. This decline in stock value was prompted by macro-economic trends that worked against the economic competitiveness of renewable energy. Aggressive interest rate hikes by the Federal Reserve, material shortages, global supply chain dislocations and American industrial policies increased the cost of building wind and solar plants.[133] By August 2024, renewable energy ETFs total returns (consisting of the stock prices plus dividends) were nearly equal with New England's pipeline companies and well below XLE and TPYP.

Renewable Energy Returns vs. Conventional Energy Returns[134]

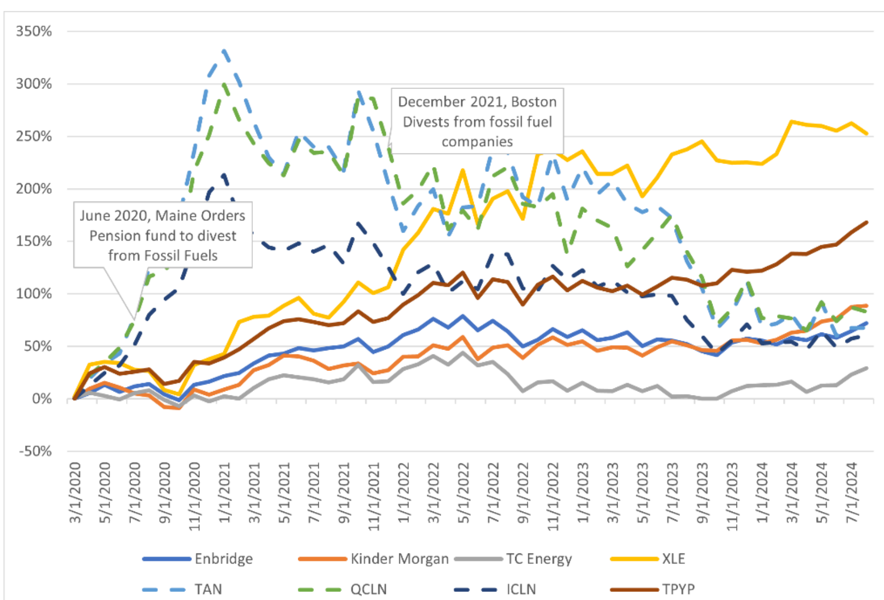


FIGURE 31. Diversification plays an important role in this portfolio. While XLE may be the best performing asset as of August 2024, a glut in crude oil could erode a significant portion of its value. Falling interest rates may cause solar developers to have improved margins, spurring a recovery in renewable energy ETFs.

SEE FIGURE 32. Total Returns

Over the same period, macro-economic and geopolitical trends worked in favor of conventional energy producers. The largest components of XLE, Exxon Mobil and Chevron, benefited from a spike in oil prices during 2022. While oil prices have declined, they remained higher than they were during the Covid years of 2020 and 2021. Oil companies increased investors' returns by raising cash dividends and repurchasing their shares. The appreciation in oil stocks caused XLE to rise 250 percent since March 1, 2020.

Normally, a prudent fiduciary unconstrained by arbitrary ESG metrics or a fossil fuel divestment mandate would be able to hedge both assets against each other. The fund's optimal decision throughout 2020 would have been to channel gains from renewable energy into fossil fuel assets. With a seven percent cash dividend locked in, the fund manager would have secured cashflow to help balance payments, freeing up funds that could be reinvested in higher risk investments. A fund manager considering the potential of a rate cut, federal subsidies, or other catalyst may deem it prudent to make a stake in the Renewable ETFs after they've fallen more than 50 percent from their peaks in 2021. ESG metrics and fossil fuel divestment mandates prevent fiduciaries from exploiting trends in the energy space that would generate the highest returns. Investment in the energy space would be limited to clean energy projects. Worse yet, renewable energy securities fail to offer the same cash return on equity offered by pipeline and other oil and gas companies (Figure 33, Dividend Returns).

SEE FIGURE 33: Dividend Returns

Between March 2020 and August 2024, XLE and TYPY returned over seven percent per year. And Kinder Morgan and Enbridge shares returned nearly seven percent exactly. The annualized rate of return paid in dividends alone was seven percent, which is the long run average return accrued to small business and private capital.[135] The renewable energy ETFs cash dividend returns were significantly lower. When annualized, the average rate of return paid by renewable energy ETFs was 0.78 percent. Given the choice between a renewable energy ETF and a fixed return from a pipeline company, a fiduciary would prefer the returns offered by fossil fuel companies guaranteed seven percent rate of return is equal to or exceeds the funds discount rate.

Fiduciaries use discount rates to determine the funding ratios. Funding ratios are a widely used barometer for a fund's financial health. They are

	Total Returns
XLE	253%
TPYP	168%
QCLN	83%
Kinder Morgan	88%
Enbridge	72%
TAN	68%
ICLN	60%
TC Energy	29%

FIGURE 32: Total Returns accrued per share from March 2020 – August 2024

	Initial Share Price	Cash Dividends	Percent Gain from Dividends	Annualized Return
XLE	$29.06	$12.12	41.69%	8.07%
TPYP	$13.58	5.011	37%	7.24%
Enbridge	$29.09	$10.44	35.89%	7.07%
Kinder Morgan	$13.92	$4.95	35.57%	7.01%
TC Energy	$44.30	$12.10	27.31%	5.53%
ICLN	$9.55	$0.87	9.08%	1.95%
QCLN	$20.05	$0.87	4.34%	0.95%
TAN	$25.23	$0.14	0.55%	0.12%

FIGURE 33: Dividend Returns shows the percent return in cash dividends paid by XLE, Enbridge, Kinder Morgan, TC Energy, ICLN, QCLN and TAN from March 2020 to August 2024.

the net-present value of the assets a fund owns divided by the fund's total liabilities over a period of time, typically 30 years.[136] Pension fund managers want cash returns that can match the discount rate. Matching cashflow with the discount rate allows the fund to balance the fund's long-run assets and liabilities, resulting in a healthier funding ratio.

Discount rates used by fund managers typically reflect the rate of return earned on money invested in small businesses.[137] In 2021, state and local pension fund's discount rate averaged 7 percent.[138] New England's pension funds employed similar rates. In 2023, the discount rates used to measure the BRS and Boston Teachers were 6.9 percent and 7 percent respectively.[139] Maine's local, state, and teacher funds all use a 6.5 percent discount rate.[140] Additionally, these discount rates reflect the fiduciaries implicit preference for returns, and partly explain why pension funds hold large positions of fossil fuel companies.

Maine's pension funds seeking a discount rate of 6.5 percent implies fund managers are seeking a return on investment — preferably in cash — of at least 6.5 percent per year. Fossil fuel companies paying 7 percent offer a superior return on investment. The future cashflows derived from the dividends alone will be able to keep pace with the lost value from the funding ratio. Volatile assets, like renewable energy ETFs are inherently riskier investments for fiduciaries. When the value of renewable energy ETFs decline, there is no cashflow to mitigate the impact on the funding ratio. Total asset value will decline with the share price, lowering the funding ratio.[141]

Impact on Maine's Pension Fund

After 2021 legislation, Maine Public Employee Retirement System began the process of divesting from fossil fuel companies. While the law instructed the pension fund to divest from fossil fuels by 2026, aggressively unwinding investments would be financially irresponsible. According to MainePERS 2023 divestment report, the state employee pension fund still holds $1.2 billion in fossil fuel assets which comprise 6.5 percent of the fund.[142]

Given Maine's funds goal of earning a return of 6.5 percent and the high dividends paid by the fossil fuel industry, AOER assumes that Maine's pension funds current investments in fossil fuel companies generate at least 6.5 cash dividend return per year. If Maine continues to divest from fossil fuels at a rate of 6.5 percent per year, Maine will be able to completely divest by 2033. In that time, the total value of lost cash dividends from the energy sector would be $146.45 million (FIGURE 35: MainePERS Fossil Fuel Divestment Schedule).

SEE FIGURE 34: Maine Divestment Continues at Trend of 6.5% Impact on Cash Dividends

However, if MainePERS accelerates divestment to maintain compliance with H.P. 65's complete divestment target of 2026, then MainePERS stands to lose a much larger sum of money. By 2033, Maine will likely have foregone over $665 million in dividend income from fossil fuel companies. (See Figure 35)

	Fossil Fuel Investments (millions)	Energy Dividends (millions)	Foregone Dividends (millions)
2022	$1,408	$99	$0
2023	$1,215	$85	$13
2024	$1,139	$80	$19
2025	$1,000	$70	$29
2026	$823	$58	$41
2027	$634	$44	$54
2028	$458	$32	$66
2029	$310	$22	$77
2030	$197	$14	$85
2031	$117	$8	$90
2032	$65	$5	$94
2033	$34	$2	$96
Total		$518.05	$664.50
Lost Funds		$146.45	

FIGURE 34. MainePERS Fossil Fuel Divestment Schedule shows the total lost dividends from fossil fuel companies as Maine PERS continues its divestment plan. Values for 2024 – 2033 were estimated using 2023's rate of divestment 6.5 percent.

SEE FIGURE 35. Maine Divestment After 2021 Legislation

Pipeline infrastructure and fossil fuel companies are not Maine's pension fund's only source of cash revenue. Investments in real estate investment trusts (REITs) and preferred stock can offer equal or even higher dividends. However, overinvesting in one asset class narrows the focus of the fund, increasing exposure to investment risk. Without increasing investment, MainePERS could replace the $665 million in dividends by increasing employee contribution rates. However, this would take more pay out of civil servant's monthly income.

Furthermore, divesting from fossil fuels will reduce fiduciaries' ability to diversify within the energy space. Under these policies, fiduciaries distributing funds among assets in the energy space will be pigeonholed solely into renewables. Furthermore, the cash return on investments will be lower. By reducing the variety of investments, fund managers will be overweight in other sectors to compensate.

	Fossil Fuel Investments (millions)	Energy Dividends (millions)	Foregone Dividends (millions)
2022	$1,408	$99	$0
2023	$1,215	$85	$13
2024	$737	$52	$47
2025	$271	$19	$80
2026	$61	$4	$94
2027	$0	$0	$99
2028	$0	$0	$99
2029	$0	$0	$99
2030	$0	$0	$99
2031	$0	$0	$99
2032	$0	$0	$99
2033	$0	$0	$99
Total	N/A	$258.42	$924.13
Lost Dividend		$665.71	

FIGURE 35. MainePERS Fossil Fuel Divestment Schedule shows the total lost dividends from fossil fuel companies as MainePERS continues its divestment plan. Values for 2024 – 2026 were estimated assuming a divestment rate of 50 percent per year with a complete exit from fossil fuel assets by January 1, 2027, maintaining compliance with H.P. 65.

Finally, ESG metrics and investment policies will prevent fossil fuel companies from financing the construction of new pipelines in the region. Should New England's net-zero plans fail to materialize, the region will see increased dependency on natural gas and in-home heating. Under normal circumstances, a pension fund could purchase stakes or debentures to help finance the construction of a new pipeline. However, ESG blocks the flow of funds from pension funds to pipeline companies and prevents cheap natural gas from flowing into the region.

ESG's arbitrary restrictions are preventing pension fund managers from investing in assets that would yield the highest return possible in a diversified portfolio. As cities and states throughout New England continue to adopt these arbitrary limits, pension funds will be leaving billions in cash dividends on the table while simultaneously subjecting funds to higher volatility and risk.

Conclusion

Compliance with the New England Decarbonization Plans would cost $815 billion through 2050. New England families would see their electric bills increase by an average of nearly $99 per year. Commercial businesses would see their costs increase by $489 per year. Industrial (manufacturing) customers would see their electric bills increase by an average of almost $5,280 per year.

The costs incurred in the New England Decarbonization Plans are driven by a massive buildout of solar panels, offshore wind turbines, onshore wind turbines and transmission lines, in addition to the costs associated with higher taxes, generator profits and the cost of building battery storage facilities to provide power when the sun is not shining or the wind is not blowing.

While adding power plant capacity to the grid may sound like a good thing, increasing capacity merely to meet green energy mandates, rather than meeting electricity demand, is an unnecessary cost that will harm New England families and the region's economy.

Other states are tacitly admitting that the plans for a net zero grid will leave many vulnerable. Colorado's Department of Health Care Policy and Financing (HCPF) is giving away battery backup supply systems to Medicaid recipients who are dependent on medical equipment with an internal battery life of 2-4 hours. Even if New England were to follow suit, the free batteries are only expected to last 12 hours, shorter than the 18-hour blackout scenario described in this study.[143 144]

Simultaneously, adoption of ESG policies to introduce hydrogen blending into natural gas would raise the costs of heating for the many New England households dependent on the fuel to heat their homes.

In the end, the idea that New England can use policies based on net zero and ESG promises to heat and power the region is a dangerous and unserious proposition.

Always On Energy Research AOER believes every resident in every state has the right to know how much energy policy passed at local, state, and federal levels will cost them in terms of standard of living, including monetary and reliability.

The Ethan Allen Institute's mission is to influence public policy in Vermont by helping its people to better understand and put into practice the fundamentals of a free society: individual liberty, private property, competitive free enterprise, limited and frugal government, strong local communities and personal responsibility.

The mission of the **Josiah Bartlett Center for Public Policy** is to develop and advance practical, free-market policies that promote prosperity and opportunity for all.

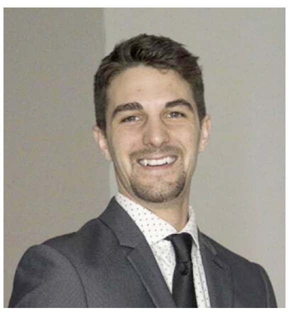
Maine Policy Institute is a nonprofit, nonpartisan organization that works to expand individual liberty and economic freedom in Maine. Maine Policy is the strongest voice in Augusta for taxpayers and believes in an open, transparent, and accountable state government.

The Rhode Island Center for Freedom and Prosperity is dedicated to providing concerned citizens, the media, and public officials in Rhode Island with empirical research data, while also advancing market-based solutions to major public policy issues in the state.

Yankee Institute is the eyes, ears and voice for hard-working people who want a prosperous Connecticut. Our common-sense solutions drive positive legislative results to strengthen our communities and build a vibrant, hopeful future.

American for Prosperity Foundation. We believe in people. When Americans have freedom and opportunity, they can achieve extraordinary things. At Americans for Prosperity Foundation, we empower and educate Americans on the proven and principled solutions to our country's most challenging issues.

Isaac Orr is a founder and Vice President of Research at Always On Energy Research, where he conducts energy modeling and writes about energy and environmental issues, electricity policy, and natural resource development. His writings have appeared in The Wall Street Journal, USA Today, the New York Post, The Hill, and many other publications. He and his colleague Mitch Rolling have modeled the cost and reliability impacts of Environmental Protection Agency regulations in the Midcontinent Independent Systems Operator and Southwest Power Pool. They have also evaluated the cost and reliability implications of energy policies in more than twelve states. Isaac grew up on a small family dairy farm in Wisconsin, so he cares deeply about the issues affecting rural America.



Mitch Rolling is a founder, and Director of Research at Always On Energy Research, where he models energy proposals, analyzes the energy industry and electricity policy, and writes about energy and environmental issues. His research has been featured in publications such as The Wall Street Journal and Forbes. Mitch and his colleague Isaac Orr co-authored an award-winning report highlighting the impact of Minnesota's 50 percent renewable energy proposal and have designed several energy models to analyze the impact of energy proposals in twelve states and Environmental Protection Agency regulations in the Midcontinental Independent System Operator (MISO) and Southwest Power Pool (SPP). Mitch graduated from the University of Minnesota in 2018 with a bachelor's degree in history, and he earned an MS in Finance and Economics at West Texas A&M University in 2022.

Appendix

Annual Average Additional Cost Per Customer. The annual average additional cost per customer was calculated by dividing the average yearly expense of the New England Decarbonization Plans by the number of electricity customers in the region.[145] This methodology is used because rising electricity prices increase the costs of all goods and services. Businesses will pass these additional costs onto consumers, effectively increasing the cost of everything. Therefore, this method helps convey the total cost of the plans for New England households in a way that is more representative than calculating the costs associated with higher residential electric bills.

Annual Average Rate Per Customer Class. The annual average additional cost per residential, commercial and industrial rate class customer was calculated by applying the overall cost per kWh of New England decarbonization plan compliance during the time horizon of the study to rate classes based on historical rate factors in New England. Rate factors are determined by the historical rate ratio (rate factor) of each customer class.

For example, electricity prices for residential, commercial and industrial rate classes in New England were 28.72, 19.23 and 15.80 cents per kWh in 2023, respectively. Based on general electricity prices 22.78 cents per kWh, residential, commercial and industrial rates had rate factors of 1.26, .84 and .69, respectively. This means that, for example, residential customers have historically seen electricity prices 26 percent above general rates. This analysis continues these rate factors to assess future rate impacts for each rate class.

Assumptions for Levelized Cost of Energy (LCOE) Calculations. The main factors influencing LCOE estimates are capital costs for power plants, annual capacity factors, fuel costs, heat rates, variable operation and maintenance (O&M) costs, fixed O&M costs, the number of years the power plant is in service, and how much electricity the plant generates during that time, which is based on the capacity (MW) of the facility and the capacity factor.

LCOE values for existing natural gas generators were estimated using historical construction costs based on the average plant life of each energy source and current variable and fixed operation and maintenance (O&M) expenses. This method was chosen in the absence of relevant FERC Form 1 filings in the ISO-NE region and data similar for Independent Power Producers (IPP). All other existing generators were estimated using the U.S. average cost for power plants in FERC Form 1 filings.

These LCOE values are inserted into the model and adjusted annually based on annual capacity factors for existing resources.

LCOE values for new power plants were calculated using data values presented in the Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies for the Annual Energy Outlook 2025.[146] These values are held constant during the model run. The cost of repowering power facilities that need it at the end of their useful lives is accounted for in each value. These values are described in greater detail in the following subheadings:.

1) Capital Costs, and Fixed and Variable Operation and Maintenance Costs Capital costs and expenses for fixed and variable O&M for new offshore wind, onshore wind, solar and battery storage were obtained from the Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies for the Annual Energy Outlook 2025.[147] Region 7 capital costs were used, and national fixed and variable O&M costs were obtained from the Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies for the Annual Energy Outlook 2025 report.[148]

2) Unit lifespans Different power plant types have different useful lifespans. Our analysis takes these lifespans into account for our Levelized Cost of Energy analysis.

3) Onshore and offshore wind turbines last 20 years Federal LCOE estimates seek to compare the cost of generating units over a 30-year time horizon.[149] This is problematic for wind energy LCOE estimates because the National Renewable Energy Laboratory reports the useful life of a wind turbine is only 20 years before it must be repowered. Our analysis corrects for this error by using a 20-year lifespan for wind projects before they are repowered and need additional financing.

4) Solar panels last 25 years Our analysis uses a 25-year lifespan for solar because this is the typical warranty period for solar panels. These facilities are rebuilt after they have reached the end of their useful lifetimes.

5) Battery storage lasts 15 years Battery storage facilities are expected to last for 15 years. Battery facilities, like wind and solar, are rebuilt after reaching the end of their useful lifetimes.

6) Fuel cost assumptions Fuel costs for existing power facilities were estimated using the most recent estimates from the ISO-NE 2023 Internal Market Monitor Report.[150]

7) Nuclear fuel costs Fuel costs for existing nuclear plants were assumed to be $6.35 per MWh, which was the latest available price according to EIA.

8) Natural gas fuel costs Existing natural gas prices were assumed to be $3/mmBTu based on data obtained from the ISO-NE 2023 Internal

Market Monitor Report.[151] We held this fuel cost constant through 2050.

9) Coal fuel costs Existing coal fuel cost assumptions of $22.09 per MWh were based on 2020 FERC Form 1 filings.

10) Levelized Cost of Transmission, Taxes, and Transmission Lines This report calculated the additional levelized transmission, property and income tax, and utility profit expenses resulting from each new power source during the course of the model and according to the additional capacity in MW installed and generation in MWh of that given source. Capacity installed is used to determine capital costs and additional expenses (transmission, state taxes and generator profits) of each electricity source over the course of its useful lifespan.[152]

Assumptions for Levelized Cost of Intermittency (LCOI) Calculations. This report also calculated and quantified the levelized cost of intermittency (LCOI) for offshore wind, onshore wind and solar energy on the entire energy system. These intermittency costs stem from the need to build backup battery storage facilities to provide power during periods of low wind and solar output, which we call "battery storage costs," in this report and the need to "overbuild and curtail" wind and solar facilities to limit the need for battery storage. It is important to note that these costs are highly system specific to the mix of resources being built and operated in any given area.

1) Battery storage costs We calculate battery storage costs by determining the total cost of building and operating new battery storage facilities to meet electricity demand during the time horizon studied in the New England Decarbonization Plans. These costs are then attributed to the LCOE values of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

Attributing battery storage costs to offshore wind, onshore wind and solar allows for a more equal comparison of the expenses incurred to meet electricity demand between non-dispatchable energy sources, which require a backup generation source to maintain reliability, and dispatchable energy sources like coal, natural gas and nuclear facilities that do not require backup generation.

2) Overbuilding and curtailment costs The cost of using battery storage for meeting electricity demand during periods of low wind or solar output is prohibitively high, so many wind and solar advocates argue that it is better to overbuild renewables, often by a factor of five to eight compared to the dispatchable thermal capacity on the grid, to meet peak demand during these low wind and solar periods. These intermittent resources would then be curtailed when wind and solar output improves.

As wind and solar penetration increase, a greater portion of their output will be curtailed for each additional unit of capacity installed.[153]

This "overbuilding" and curtailing vastly increases the amount of installed capacity needed on the grid to meet electricity demand during periods of low wind and solar output. The subsequent curtailment during periods of high wind and solar availability effectively lowers the capacity factor of all wind and solar facilities, which greatly increases the cost per MWh produced.

Our model indicated there would be large periods of curtailment in the future grid due to the large capacity additions of offshore wind, onshore wind, and solar resources. This is consistent with the findings of the ISO-NE 2021 Economic Study: Future Grid Reliability Study Phase 1:

"On high-renewable days, typically during the spring or fall seasons, there is a large amount of both offshore wind and PV, which leads to large amounts of curtailment. During peak solar output hours, we observed that even with simultaneous charging of BESS, pumped storage, and EV Flex (as explored in Alternative B), and external tie-lines exporting at their limits, there was more than 15.4 GWh of energy that needed to be curtailed in a single hour. The system was unable to capture this renewable energy for use at a later time due to insufficient storage (600 MW of BESS plus existing pumped hydro storage). The system would require increased energy storage capability to utilize this curtailed, renewable energy."[154] "Regardless of the specific gas type in use, the FGRS analysis shows immense amounts of renewable energy curtailment in most cases, but particularly in aggressive electrification and renewable deployment cases."

Annual curtailment levels for this model were estimated based on hourly load forecasts and were found to reach up to 64 percent of total wind and solar generation by the end of the model. (See Figure 36)

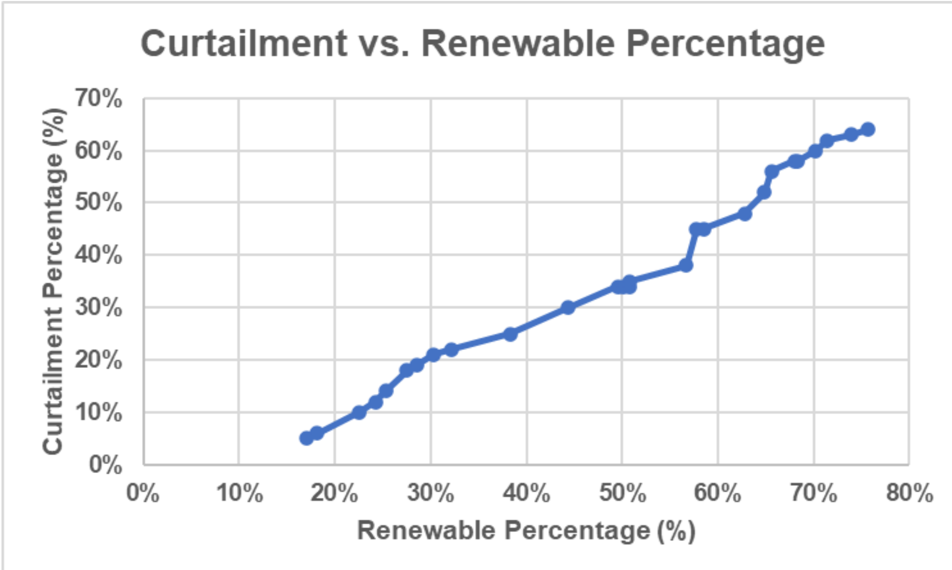


FIGURE 36. Curtailment increases to nearly 64% by 2050 as more intermittent generation is brought online.

Rising rates of curtailment stemming from the overbuilding of the grid effectively lower the capacity factor of all generating resources on the grid, thereby increasing the levelized cost of energy, which is a calculation of power plant expenses divided by the generation of the plant.

3) Coincident peak load Our analysis assumed coincident winter peak periods of demand because the *2050 Transmission Study* found for winter periods, each state in New England was at or near its own peak load while New England as a whole was at its overall peak load, so a single snapshot in time captured worst-case or near-worst-case conditions in all six states.

4) Cost of compliance modeling This analysis utilizes cost of compliance modeling to determine the cost of the electric system in New England. This approach, which does not consider the impact of the resource portfolio on wholesale prices, is appropriate because most large-scale wind and solar facilities are procured through state-sponsored long-term contracts.

As the system becomes more saturated with these non-dispatchable resources, it is unclear whether the markets will be able to produce the necessary incentives to keep dispatchable units online, resulting in a circumstance where these generators are issued reliability payments to remain available for periods of peak demand. As result we assumed generators would secure contracts to recoup their capital costs plus a return of 7.05 percent.

5) Electricity consumption assumptions Our model estimates electric-

ity consumption in 2050 using the projected hourly load shape for 2033 and monthly peak demand for 2050 (see Figure 37). Electricity consumption is incrementally increased every year from 2024 to 2050 to arrive at this consumption level, which was more than 244 million MWhs in 2050.

6) Energy storage dispatch Energy storage is assumed to be saved for periods of high demand with low wind and solar output. This differs from modeling exercises performed by ISO-NE, where storage facilities are assumed to use locational marginal price (LMP) arbitrage to determine when these resources would be economically dispatched. For each day modeled, the energy storage algorithm forecasted one week ahead to find opportune times to charge and discharge energy and maximize profitability.

This decision was made because using storage systems to capture higher prices during via arbitrage would often lead to situations where the energy storage was depleted before a period of wind and solar drought to following week, leaving the system short of energy.

7) Export Income Assumptions As ISO-NE increases the installed capacity on its system, there is an opportunity to sell electricity to neighboring regions, including Hydro Quebec, New Brunswick and New York. However, our analysis did not account for these potential export revenues.

One complication in calculating these revenues is the large uncertainty of wholesale power prices in the coming decades. Larger penetrations of zero-marginal cost wind and solar resources will ultimately drive down wholesale power prices during periods of strong wind and solar production. This will reduce the prices of potential exports to neighboring regions, who can purchase low cost, or even negatively priced electricity, reducing the revenues obtained by wind and solar generators.

In contrast, periods of low wind and solar output will cause wholesale prices to rise, thus increasing the cost of imports into ISO-NE. This may create a "buy high, sell low" dynamic for electricity prices on ISO-NE system in the coming decades.

Hourly Load, Capacity Factors and Peak Demand Assumptions

The hourly load shape used in our modeling was extrapolated using ISO-NE projected load shapes for 2033 and projected monthly peak demand in 2050. This resulted in a peak demand of 57 GW in December 2050. New Hampshire electrification was then taken out of this load shape, assuming the state would not electrify motor vehicles and continue to use natural gas for home heating. This resulted in a peak demand of roughly 52.5 GW.

Hourly output from intermittent generating resources, such as on and offshore wind and solar, were derived from the U.S. Energy Information Administration (EIA)[155] and ISO-NE variable energy resource (VER) data.[156]

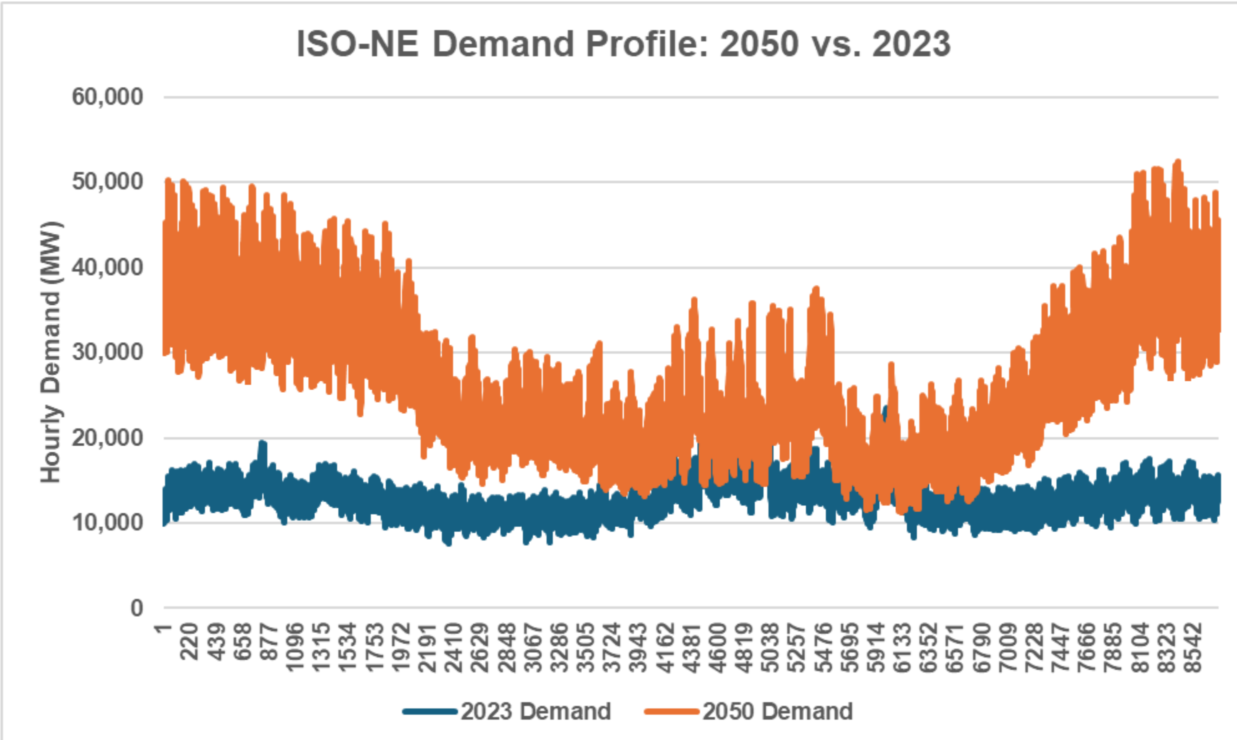


FIGURE 37 shows the difference between the historical 2023 hourly demand in ISO-NE and projected 2050 hourly demand after load growth and electrification efforts.

1) Impact on electricity rates The table below shows annual additional electricity rates by customer class using the cost of the New England Decarbonization Plans and adjusting for the rate factor described above in cents per kWh.

Cents/kWh	2024	2025	2026	2027	2028	2029	2030
Residential Rate Increase	0	0.91	2.38	3.38	4.06	4.96	5.71
Commercial Rate Increase	0	0.61	1.60	2.26	2.72	3.32	3.83
Industrial Rate Increase	0	0.50	1.31	1.86	2.24	2.73	3.14
Average Rate Increase	0	0.72	1.89	2.68	3.22	3.94	4.53
Cents/kWh	2031	2032	2033	2034	2035	2036	2037
Residential Rate Increase	6.78	8.17	10.13	12.04	13.55	14.00	14.63
Commercial Rate Increase	4.54	5.47	6.78	8.06	9.08	9.37	9.80
Industrial Rate Increase	3.73	4.50	5.57	6.62	7.46	7.70	8.05
Average Rate Increase	5.38	6.48	8.03	9.55	10.75	11.10	11.60
Cents/kWh	2038	2039	2040	2041	2042	2043	2044
Residential Rate Increase	15.43	17.38	19.69	21.03	23.59	26.04	28.13
Commercial Rate Increase	10.33	11.64	13.18	14.08	15.80	17.43	18.84
Industrial Rate Increase	8.49	9.56	10.83	11.57	12.98	14.32	15.48
Average Rate Increase	12.24	13.79	15.62	16.68	18.71	20.65	22.32
Cents/kWh	2045	2046	2047	2048	2049	2050	
Residential Rate Increase	30.04	30.84	32.76	34.52	35.70	36.30	
Commercial Rate Increase	20.12	20.65	21.94	23.12	23.91	24.31	
Industrial Rate Increase	16.53	16.97	18.02	18.99	19.64	19.97	
Average Rate Increase	23.83	24.47	25.99	27.38	28.32	28.79	

FIGURE 38. Impact of New England decarbonization plan on electric rates.

2) Imports Our analysis assumed all of the transmission lines in the *2050 Transmission Study* would be operational. These consist of:

1,000 MW imported from New Brunswick over existing 345 kV AC ties.

1,850 MW imported from New York over the existing 345 kV, 230 kV, 115 kV and 69 kV AC ties.

1,400 MW imported from Quebec over the existing Phase II HVDC tie (interconnected at Sandy Pond substation in Ayer, Massachusetts).

225 MW imported from Quebec over the existing Highgate HVDC back-to-back converter (interconnected in Highgate, Vermont).

1,200 MW imported from Quebec over the under-construction New England Clean Energy Connect HVDC tie (interconnecting at Larrabee Road substation in Lewiston, Maine).

1,000 MW imported from Quebec over a hypothetical new HVDC tie between Quebec and Vermont (assumed to interconnect at the Coolidge substation in Cavendish, Vermont).

However, we assumed that ISO-NE would have 1,800 MW of firm import capacity in 2050 except when Hydro Quebec needs to meet its domestic demand. Given the changing peak demand seasons for ISO-NE, this analysis used real-time electricity demand data from Hydro Quebec to determine if there would be enough power plant capacity on the HQ system to meet its domestic needs. If there was not, exports to ISO-NE were curtailed.

The cost of imports from Hydro Quebec was assumed to be 7.5 cents per kWh based on the most recent annual report published by Hydro Quebec.[157]

3) No "Load Modifying Resources" Our model does not allow for the use of Load Modifying Resources (LMRs) or demand response (DR) in determining how much reliable capacity will be needed to meet peak electricity demand in the New England Decarbonization Plans.

Instead, battery capacity and excess wind and solar capacity is built to provide enough power to supply ISO-NE's electricity needs under the Decarbonization Plans at all times based on a test year using historical generation in ISO-NE in 2023, and hourly capacity factors for wind and solar from the EIA Electric Grid Monitor and ISO-NE VER d.[158] Battery storage capacity was assumed to be 95 percent efficient and fully charged at the start of the test year.

We acknowledge that voluntary LMRs and DRs can play a role in optimizing system cost and reliability. However, we believe that DR resources are being inappropriately used by many wind and solar special interest groups to manipulate their models to unrealistically reduce the amount of capacity needed to meet peak demand, and thus artificially suppress the cost of their proposals. In this way, these groups are essentially manipulating the amount of capacity needed to meet current electricity demand and not providing an apples-to-apples comparison of the cost. Their proposals will effectively place more responsibility on behalf of the customer to keep the grid online.

4) New Hampshire electricity demand Because New Hampshire has not adopted deep decarbonization policies, this analysis projects that the state will continue to utilize conventional energy sources such as natural gas and heating oil for home heating, and internal combustion engines. This serves to reduce the observed peak load on the ISO-NE system.

New Hampshire's peak load reduction was calculated by taking the difference of New Hampshire's projected demand for electrification and a constant growth of New Hampshire demand based on historical growth rates of 1.25 percent. This difference was subtracted out of the hourly load shape to account for New Hampshire's energy policy that does not include electrification efforts seen in other states.

5) Nuclear relicensing All existing nuclear power plants were assumed to remain operational through the model run. This assumption greatly reduced the need for new onshore wind, offshore wind, solar and battery storage resources and maintains system reliability.

This was demonstrated in the ISO-NE 2021 Economic Study: FIGURE Grid Reliability Study Phase 1, where retiring the existing nuclear power plants resulted in massive blackouts in the region, with customers losing power for 79 hours throughout the year, peaking at 6,160 MWh (19.7 percent of load) unserved energy during a single hour. The ISO-NE 2021 Economic Study: FIGURE Grid Reliability Study Phase 1 also found the retirement of nuclear units led to an increase in carbon dioxide emissions of up to 50 percent.

6) Nuclear restrictions Maine and Connecticut will maintain a moratorium until the identification of a demonstrable technology or a means for high level waste disposal or reprocessing is found.[159] Connecticut in 2022 passed legislation allowing for new reactors to be sited at the existing nuclear facility located in the state.[160]

Meanwhile, Massachusetts, Rhode Island and Vermont prohibit new nuclear power plants unless they are approved by the state legislature.[161] Maine and Massachusetts also require voter approval for new reactors.[162,163]

7) Offshore wind costs This analysis uses the capital cost, and operations and maintenance cost assumptions in the U.S. EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, a capacity factor of 50 percent, a 20-year useful life, and an assumed weighted average cost of capital of 7.6 percent.[164]

Using these assumptions, we calculated an unsubsidized levelized cost of energy of $149 dollars per MWh for new offshore wind (See Figure 39). These estimates are nearly identical to the subsidized costs of offshore wind projects signed in New York, which were $150 per MWh.

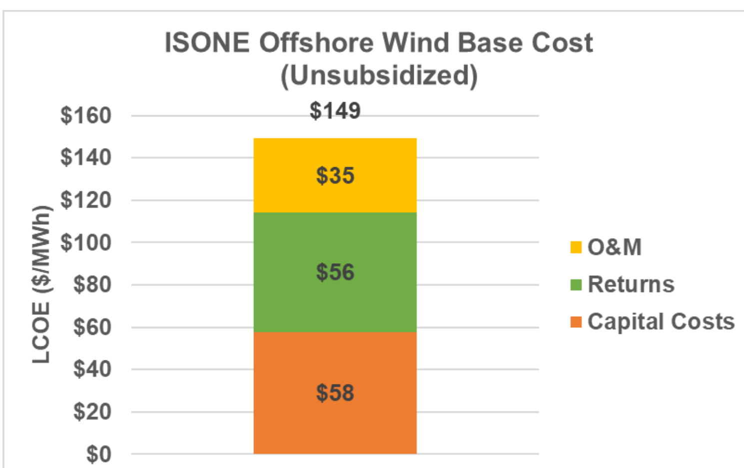


FIGURE 39. This figure shows the unsubsidized Levelized Cost of Energy used as our "base cost" calculation in our model, which is more conservative than the contracts currently being signed in New York that include the federal Investment Tax Credit.

As a result, our cost assumptions were generous to the offshore wind industry because we used the more optimistic capital costs in EIA's latest capital cost estimate guide, rather than the costs of power purchase agreements for offshore wind in New York.

These costs differ from those shown in Figure 19 because not all of the offshore wind facilities have not reached the end of their useful lives, and therefore the costs are being divided over fewer megawatt hours.

8) Plant Construction by Type This analysis assumes no new carbon-dioxide emitting power plants will be built outside of New Hampshire, where the total installed capacity of natural gas power plants is roughly 5,650 MW. Existing natural gas capacity is assumed to remain online but operate at low-capacity factors in the remaining five states.

Under the New England Decarbonization Plans, states would add offshore wind, onshore wind, solar facilities, battery storage capacity and build new transmission lines to reduce emissions, consistent with the *2050 Transmission Study* assumptions.

9) Plant Retirement Schedules Our model uses retirement assumptions from the *2050 Transmission Study*, where all coal, oil, diesel, and municipal solid waste-fueled generators, as well as a portion of today's natural gas-fueled generation were retired by 2035. For our analysis, existing steam turbine gas plants were retired while others remained in service and were repowered as needed to keep online.

The remainder of today's natural-gas-fueled generation, as well as biomass, nuclear, hydroelectric, and renewable generators, were assumed to remain operational through 2050.

10) Time Horizon Studied This analysis studies the impact of the New England Decarbonization Plans on electricity prices from 2024 to 2050. This time horizon is examined because like a mortgage, power plants owners pay off the cost of the plant each year, meaning decisions made today will affect the cost of electricity for decades to come. As such, the total costs highlighted by this study do not represent the total costs incurred by the New England Decarbonization Plans, but rather the total cost that electricity customers would pay off through 2050.

11) Transmission ISO-NE estimates rising peak demand will cost roughly $750 million per gigawatt (GW) of load added from 28 GW to 51 GW, and roughly $1.5 billion per GW from 51 GW to 57 GW.[165]

ISO-NE notes the New England grid with 100 percent heating and transportation electrification is expected to result in a peak load of around 57 GW, but a lower peak load could be achieved if less electrification of the transportation and home heating sectors.

In our analysis, New Hampshire serves to reduce peak load by 4.5 GW by continuing to heating homes with natural gas and fuel oil and by continuing to use internal combustion engines.[166,167]

12) Wind and Solar Degradation According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose 1 percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[168] However, our study does not take wind or solar degradation into account.

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