Carbon Pricing for New England

Context, Key Factors, and Impacts

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Joseph Cavicchi
Paul Hibbard

Acknowledgments

This report has been prepared at the request of the New England Power Generators Association (NEPGA) to analyze the appropriate level for and potential impacts of a carbon pricing mechanism that may be introduced to help the New England states achieve current and future greenhouse gas (GHG) reduction requirements and goals.

This is an independent report by Joseph Cavicchi and Paul Hibbard of Analysis Group, Inc.. They wish to express their appreciation for the assistance of colleagues at Analysis Group: Scott Ario, Luke Daniels, Grace Howland, and Phillip Ross. Also, our work has benefited from input and comment from NEPGA. However, the analysis and conclusions herein reflect the independent judgment of the authors alone, and do not necessarily align with NEPGA or NEPGA's members.

About the Authors

Mr. Cavicchi, a vice president in Analysis Group's Boston office, is an expert on the economics of wholesale and retail electricity markets. Mr. Cavicchi's work focuses on issues associated with wholesale power market design and market power mitigation frameworks, wholesale and retail contracting practices, and regulatory and contract disputes arising in these marketplaces. Mr. Cavicchi has extensive experience testifying before the Federal Energy Regulatory Commission (FERC), before other federal and state regulatory authorities, and in civil proceedings. He presents and publishes frequently on issues relevant to electricity market design and industry evolution. He is also a registered professional mechanical engineer in the Commonwealth of Massachusetts.

Mr. Hibbard, a principal in Analysis Group's Boston office, has public and private sector experience in energy and environmental technologies, economics, market structures, and policy. Mr. Hibbard's work has addressed the implications of new public policy programs; the impacts of infrastructure development options on market pricing and ratepayer costs; the evolution of electricity market structures and wholesale rate design; utility ratemaking practices; and the transfer of US federal and state emission control programs to other countries. He served as chairman of the Massachusetts Department of Public Utilities, was a member of the Massachusetts Energy Facilities Siting Board, and has testified before Congress, state legislatures, and federal and state regulatory agencies. Mr. Hibbard also has authored numerous articles, white papers, and reports for journals, foundations, commissions, and industry organizations.

Introduction to Analysis Group

Analysis Group is one of the largest international economics consulting firms, with more than 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, health care analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients worldwide.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as deep experience in environmental economics and energy infrastructure development. We have worked for a wide variety of clients, including (among others) energy producers, suppliers and consumers, utilities, regulatory commissions and other federal and state agencies, tribal governments, power-system operators, foundations, financial institutions, and start-up companies.

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I. Executive Summary

A. Background

The New England states have made substantial commitments to reduce greenhouse gas (GHG) emissions on an expedited schedule. Collectively, the requirements, policies, and goals adopted by the states equate to regional economy-wide reductions in GHG emissions by 2050 of almost 80 percent relative to 2015 actual emissions. The states are motivated by a sense of urgency to address and reduce the risks of climate change, an urgency that is reflected in the aggressive standards and timelines they have adopted. There is little doubt that meeting the standards will require an unprecedented magnitude and pace of change in how the region produces and consumes energy for electricity, transportation, heating, and other uses.

Generally, *how* to meet the states' GHG reduction standards is, at this point, only loosely defined. But it is widely accepted that electrification of the transportation and heating sectors, in tandem with deep decarbonization of the electric system, will play a central role. In fact, in addition to explicit GHG reduction standards, the states have administered a wide array of complementary regulations and policies focused on the electric industry to help accelerate the development and commercialization of distributed and grid-connected hydro, wind, solar, storage, and other technologies – resources and technologies that will be essential to meeting the economy-wide GHG reduction standards.

The states' GHG reduction standards identify a destination, but reveal little about the *pathway* to get there. Yet the path the region takes to the decarbonized end-state will be the most important driver of the cost, technological, and reliability challenges customers and industry stakeholders will face along the way. The transformation will require deep and continuous investments in transportation, heating, and power system infrastructure, and will accelerate the development and commercialization of a wide array of energy-related technologies and services. It will also fundamentally transform the location, size, fuel needs, and operational characteristics of the power supply infrastructure used to keep the lights on.

In this context, the proper pricing of goods and services – including an effective price on carbon – could be essential to guide the states through a challenging transition in a way that maintains reliability, encourages efficiency, fosters innovation, and minimizes the cost to society to meet the GHG reduction mandates. There is wide agreement among economists and policy analysts that carbon pricing would be a key component of a cost-effective policy to materially reduce carbon emissions.[1] The introduction of a multi-sector carbon price would provide consumers with an important indication of the costs associated with carbon emissions and reduce consumer demand for carbon-based fuels across all sectors. We recognize, however, that regional carbon pricing on its own is likely to be insufficient to achieve reductions in CO_2 emissions commensurate with state mandates in sectors such as transportation and heating.[2] In part for this reason, analysts and policy

[1] See, for example, Robert N. Stavins, *The Future of U.S. Carbon-Pricing Policy*, Harvard Kennedy School M-RCBG Faculty Working Paper Series No. 2019-02, pp. 2–3.

[2] Recent studies estimate that applying carbon pricing to the transportation and heating sectors could reduce CO_2 emissions by 10–20% in a given year; however, to meet state mandates requires far greater annual reductions (2–3 times higher than these studies' estimates). See, for example, Marc A.C. Hafstead, Wesley Look, Amelia Keyes, Joshua Linn, Dallas Burtraw, Roberton C. Williams III, *An Analysis of Decarbonization Methods in Vermont*, Resources For The Future (RFF), January 2019, pp. 3–4 and p. 101, showing reductions of 13–19% below 2005 levels in 2025. See also Marc Breslow Ph.D., Sonia Hamel, Patrick Luckow, and Scott Nystrom, *Analysis of a Carbon Fee or Tax as a Mechanism to Reduce GHG Emissions in Massachusetts*, prepared for the Massachusetts Department of Energy Resources, December, 2014, pp. 13–14, showing annual reductions of 10–20% below 2013 levels in 2025–2040. While these studies focus on individual states, the RFF study applies carbon pricing to the entire New England region and the similar range of findings is indicative of similar percentage reductions region wide.

makers have focused on the potential for electrification of transportation and building end uses,[3] in combination with decarbonization of the electric sector, as an economic pathway to deep reductions in GHG emissions.

A meaningful multi-sector price on carbon could both help drive the investments in the electric sector necessary to support electrification and provide an important price signal to facilitate reductions from those other sectors. This is particularly true in ensuring that emissions valuation remains largely consistent across sectors. Without a multi-sector approach, the financial signal for electrification in transportation or residential heating would be undermined because CO_2 emissions have only been valued in the electricity sector.

In the New England states, the setting of GHG reduction requirements has been accompanied by supporting policies mandating growth in low-carbon generation through ratepayer-supported long-term contracting, portfolio requirements, and distributed resource incentives. Yet experience shows that pursuing these objectives through state-mandated programs and procurements will almost certainly achieve the results imperfectly, and at costs in excess of what would result through efficient carbon pricing.[4] For example, we estimate that the benefits of relying on competitive markets with efficient carbon pricing to drive new and ongoing investment in zero-emission resources necessary to achieve the states' aggregate objectives – in contrast to reliance on utility-administered resource procurements – could save consumers on the order of \$100–300 million (\$2020) over the 10-year period 2026–2035.[5] While it is difficult to estimate with certainty what the level of savings could be, the expectation of substantial savings is supported by a wealth of experience with the introduction of competition in wholesale markets and the use of market-based mechanisms for emission control.

Ironically, both the steady reductions over the past couple of decades in electric sector CO_2 emissions and ongoing state procurements have limited consideration of the potential benefits that could be obtained on a going-forward basis from establishing an effective price on CO_2 emissions for the electric sector. In the current context, recognizing that electrification of the transportation and heating sectors will be critical to meet state GHG reduction objectives and fundamentally alter the level and shape of electricity demand, the potential benefits of enhanced market-based CO_2 emission pricing should not be overlooked.

Given our expectation that it will play a primary role in support of decarbonization, at least in the early years, the electric sector is the focus of our analysis of carbon pricing. While we have the states' *economy-wide* standards in mind and recognize the importance of carbon pricing across all industry sectors being studied, our analytic focus is on the outsized role of the power sector in achieving GHG reductions through a generation resource mix that is changing simultaneously with increasing demand associated with progressive electrification of the transportation and residential heating sectors. This focus and modeling approach is consistent with an assessment of expected practical and economic pathways to meeting the states' economy-wide goals.

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[3] The focus on these sectors is consistent with ongoing and projected growth in production of electric vehicles and adoption of residential heat pumps. See, for example, BloombergNEF, Electric Vehicle Outlook 2020, https://about.bnef.com/electric-vehicle-outlook/.

[4] Evaluating the efficiency and cost effectiveness of the numerous programs and policies in play that seek to reduce GHG emissions is beyond the scope of our analysis; however; a number of key considerations are relevant when carbon pricing is not the central pillar of GHG reduction policy (Robert N. Stavins, *The Future of U.S. Carbon-Pricing Policy*, Harvard Kennedy School M-RCBG Faculty Working Paper Series, No. 2019-02, pp. 20–23).

[5] This estimate is developed conservatively assuming that zero-emission resource out-of-market costs for yet-to-be contracted resources would be 1–3% lower over the 10-year period 2026–2035 if resources were developed in response to competitive wholesale power market prices as opposed to reliance on 20-year contracts. See Susan F. Tierney and Paul J. Hibbard, *Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets*, *Technical Appendix*, October 3, 2019, pp. A-15–A-18, for additional methodology detail.

B. Analytic Method

The analytic method is described in detail throughout this report and in the Technical Appendix. It focuses on simulating the impact on the New England power system of increased electrification of New England's transportation and residential heating sectors, while simultaneously decarbonizing the supply of electricity. Briefly, it consists of the following assumptions, steps, and modeling analyses:

- **Production Cost Modeling**: We use a production cost model to simulate the operation of the New England power system for three years: 2025, 2030, and 2035. The model is used to identify the carbon price at which the resources needed to meet GHG reduction standards achieve revenue sufficiency in wholesale markets, absent any state or federal procurement mandates or subsidies. We also use modeling results to evaluate implications of the transition for power system operations, costs, and emissions.
- **Base Case Load and Resource Assumptions**: The starting point includes base case forecasts consistent with recent analyses of the New England Independent System Operator (ISO-NE) with respect to annual energy and peak summer and winter demand (net of energy efficiency, demand response, and behind-the-meter (BTM) solar photovoltaic (PV) systems); existing and expected supply resources; unit retirements (announced and at-risk); and unit operational characteristics. Generating resources include offshore wind generation projects that have received regulatory approval, other offshore wind generation additions envisioned in current state law and policy, and the New England Clean Energy Connect (NECEC) Hydro-Quebec interconnection. We then use historical daily natural gas demand and pipeline and liquefied natural gas (LNG) capacities to constrain daily natural gas availability for power generation in the winter.
- **Electrification**: The hourly load profile is modified to reflect increased demand associated with postulated increases in the uptake of electric vehicles and electric heating over the forecast horizon. Specifically, for the purpose of evaluating potential pathways we model scenarios that assume up to (1) 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles (LDVs) switch to electric vehicles; and (2) 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with oil, propane, or natural gas switch to electric heat.[6]
- **Power Sector Decarbonization**: We identify a supply curve of power sector decarbonization options involving expanded (a) energy efficiency, (b) grid-connected solar PV, (c) offshore wind, and (d) other onshore renewable resources (e.g., resources distant from load). These resources are added to the power sector modeling to meet New England GHG reduction standards.
- **Carbon Pricing**: In the final step, we iteratively run the model incorporating prices on CO_2 emissions until the required power sector low/zero-carbon generation options achieve revenue sufficiency based on current and future projected cost considering capacity and energy market (with carbon pricing) revenues.

Our simulation results allow us to observe the impact of increased electrification on the New England generation mixture, energy prices, and regional CO_2 emissions, and to map a resource development pathway that keeps the region on track to meet CO_2 emission reduction standards. The results of the analysis are used to estimate electricity market carbon prices that would support investment in and development of the zero-

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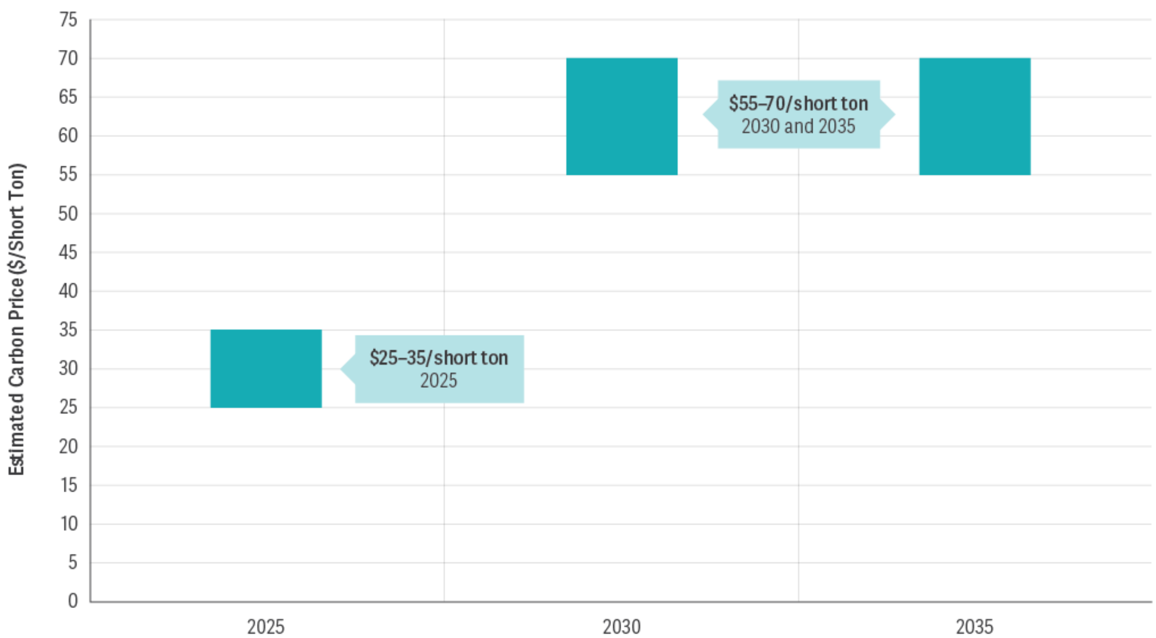
[6] The analysis in this report examines how electrification using evolving transportation and heating technologies is expected to have a role in reducing GHG emissions over the next 15 years. However, we recognize that other technologies could emerge that alter the pathways assumed in this analysis.

emission resources needed to successfully achieve reasonable progress towards state standards through a regulatory framework – carbon pricing – that drives efficient decision making by power producers and consumers, and does not require any out-of-market subsidization of resources through state regulatory action.

C. Results

Achieving states' decarbonization standards will involve sustained changes in infrastructure and operations across all energy sectors over the next 15 years (and beyond). Our key finding highlights the role that carbon pricing in (at least) the electric sector can play in this context: namely, ***sufficient progress can be supported by a progressively increasing price on emissions of CO_2 that falls in a range of $25–35/short ton CO_2 in 2025 and $55–70/short ton CO_2 in 2030 and 2035.*** (See Figure ES-1). While these prices are lower than the estimated social cost of carbon over this time frame,[7] they would allow for market competition to drive evolution of the region's power system. Reliance on market competition not only helps decarbonize the power sector by spurring innovation and minimizing consumer costs, but also can reliably address the rapidly rising electricity demand associated with continuous electrification of transportation and residential heating sectors.

Figure ES-1: Carbon Dioxide Prices



The lower range of CO_2 emission prices for 2025 recognizes that certain New England states have already made long-term contractual commitments that provide the financial support needed for various zero-emission resources to be brought into service or remain operational. Thus, in 2025 when the region is expected to be much closer to meeting its GHG reduction objectives, the carbon pricing range is driven by recent projections

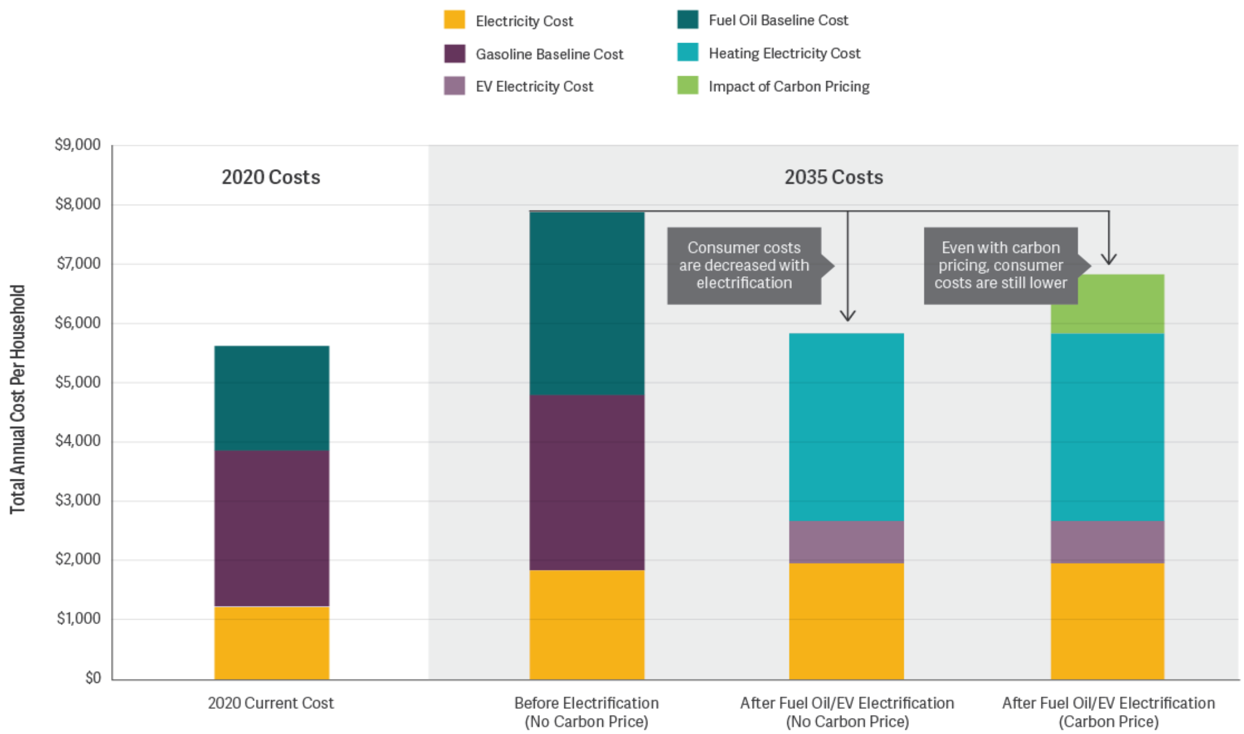
[7] EPA, *EPA Fact Sheet: Social Cost of Carbon*, December 2016, available at https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf. Note that the values reported in the EPA Fact Sheet are in $2007.

of unsubsidized levelized cost estimates for utility-scale solar and onshore wind resources. In our analysis the difference between the estimated levelized cost of unsubsidized utility-scale solar and onshore wind resources and projected market revenues is relatively low (in comparison to 2030 and 2035), and an effective carbon price range is commensurately lower.

In contrast, in 2030 and 2035, the quantity of zero-emission resources necessary to meet projected GHG reductions is much higher, and additional offshore wind and/or renewable resources distant from consumer loads are necessary for the region to remain on track to meet GHG reduction targets. These resources require a higher CO_2 emissions price to be economically viable in the absence of subsidies. Thus, the estimated cost in excess of projected market revenues in 2030 and 2035 is greater, as much more significant decarbonization is necessary. Moreover, a wider range of carbon pricing levels reflects greater uncertainty in the costs for more advanced renewable resources.

This change in how energy is used also offers consumer opportunities and cost savings. A review of consumer energy costs illustrates that electrification of transportation and heating is expected to lower household energy cost. Figure ES-2 shows the estimated decline in average residential household energy cost following electrification of light-duty vehicles and conversion of home heating system from fuel oil to an electric heat pump, assuming that consumers elect to adopt electric transportation and heating by 2035 (i.e., the technologies are cost competitive and/or incentives are provided as part of state's objectives to meet GHG emission reductions). The two bars on the left of Figure ES-2 show estimated 2020 and 2035 annual household energy costs without increased electrification; this includes the cost of gasoline, fuel oil, and electricity. The two bars on the right of Figure ES-2 show the estimated reduction in household energy cost that results following electrification both with and without a carbon price. Electrification decreases household energy cost enough that even with a carbon price estimated household energy costs are expected to decline.

Figure ES-2: Estimated Average Annual Consumer Energy Costs for Households that Adopt Electric Vehicles and Convert Home Heating System from Fuel Oil to Electric Heat Pumps



Notes:

[1] Consumer costs include electricity, vehicle fuel, and fuel oil costs. This analysis assumes that prior to electrification, a typical household owns two conventional light duty vehicles. Additionally, it assumes that both vehicles electrify.

[2] It is assumed that consumers would change to electric heating and transportation at the time of their next vehicle/heating system purchase. It is also assumed that these electric technologies would either be cost competitive with non-electric alternatives, or the difference in price would be addressed through state financial incentives consistent with state economy-wide greenhouse gas reduction targets.

[3] This analysis assumes that all electric vehicles will receive an EV rate of 10 cents (without carbon price). Carbon pricing increases the average wholesale costs to approximately 12 cents. Additionally, it assumes an EV efficiency rate of 0.32 kWh/mile.

[4] Wholesale costs are assumed to be 35% of a customer's total household electricity bill. These costs are adjusted upwards to account for increased projected LMPs in our high electrification scenarios.

[5] This analysis assumes a carbon price of $70 per short ton of CO2.

[6] Reported costs are nominal.

[7] 2020 Cost Components: Gasoline: $2,639. Fuel Oil: $1,774. Electricity: $1,214.

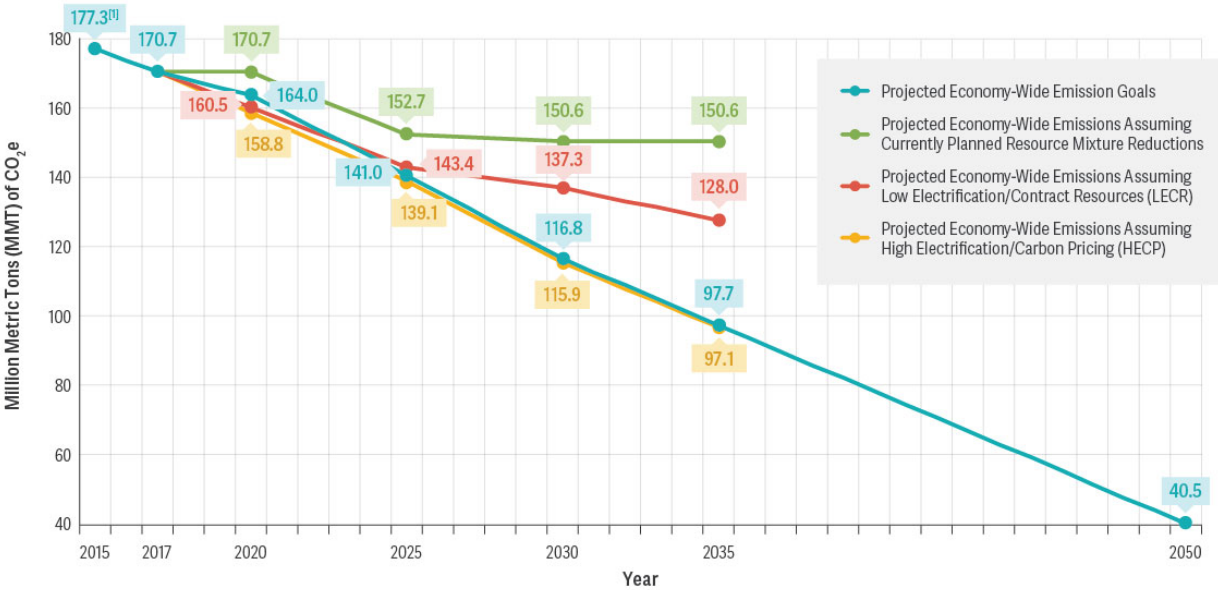
[8] 2035 Before Electrification (No Carbon Price): Gasoline: $2,978. Fuel Oil: $3,097. Electricity: $1,821.

[9] 2035 After Fuel Oil/EV Electrification (Carbon Price): EV Electricity $735. Heating Electricity: $3,172. Other Electricity: $1,948.

[10] 2035 After Fuel Oil/EV Electrification (Carbon Price): EV Electricity $735. Heating Electricity: $3,172. Other Electricity: $1,948. Carbon Pricing: $1,007.

Figure ES-3 presents the GHG emission reductions across the scenarios we evaluate relative to a line representing reasonable progress towards the states' aggregate GHG reduction standards. While the currently-expected state-driven procurement of renewable resources helps decarbonize the power sector (the light green line in Figure ES-3), it falls well short of the reductions needed to make reasonable progress towards the New England states' economy-wide GHG emission reduction targets ("reasonable progress" is represented by the blue line in Figure ES-3). This supports the conclusion that meeting state GHG standards will require continuous increases in the electrification of transportation and residential heating, in combination with power sector decarbonization. The red and yellow lines in Figure ES-3 represent scenarios combining carbon pricing (supporting additional decarbonization of the electric sector) with electrification of the transportation and residential heating sectors (with the yellow line being the most aggressive level of electrification).

Figure ES-3: New England Emission Reduction Standards Compared with Power Sector Emission Reductions from Currently Planned Renewable Resource Additions and Increased Electrification



Notes:

[1] In 2015, total GHG emissions across New England were 177.3 MMT of CO_2e (43.8 in CT, 76.1 in MA, 19.1 in ME, 17.0 in NH, 11.3 in RI, and 10.0 in VT).

[2] Economy-wide emission reduction goals are determined by aggregating each New England state's historical emissions and annual emission targets. If data is unavailable for a given year, the goal is estimated by interpolating results from years where it is available by state.

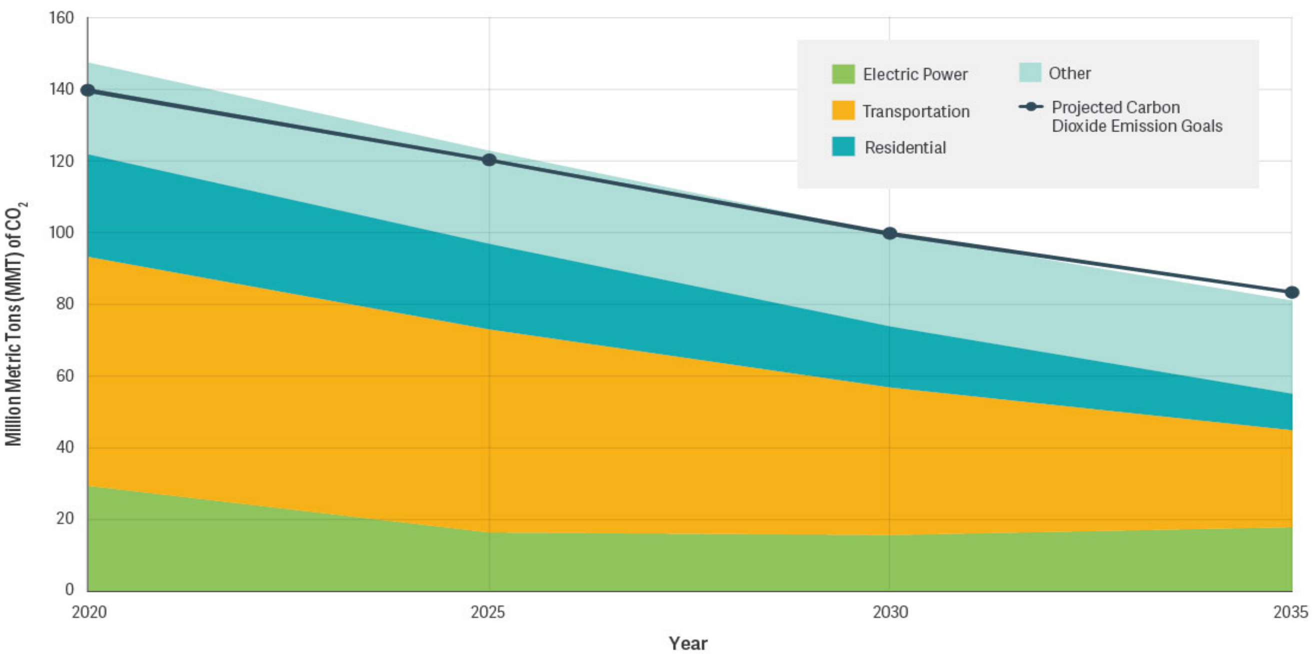
[3] Resource mixture adjustments include the retirement of fossil-fuel plants and the addition of renewable resources.

[4] The LECR scenario assumes 12.5% (2025), 17.5% (2030), and 30% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. The LECR scenario also assumes 25% (2025), 35% (2030), and 60% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

[5] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional energy efficiency (EE) at a 25% increase over assumed 2035 EE, and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

Figure ES-4 illustrates the relative impact of each economic sector on GHG emission reductions over this study's timeframe. Despite pronounced increases in electricity demand, power sector decarbonization achieves significant early reductions and continuous decreases in electric sector carbon intensity, stemming from the resource and operational effects of carbon pricing.[8] Electrification of the transportation sector drives the greatest level of reductions, particularly in later periods, while heating electrification (in particular the conversion of oil and propane heating sources) provides modest contributions to GHG emission reductions.

Figure ES-4: Projected CO_2 Emissions Changes by Sector: High Electrification



Notes:

[1] Economy-wide emission reduction goals are determined by aggregating each New England state's historical emissions by sector and annual GHG emission targets. If data is unavailable for a given year in a state, the goal is estimated by interpolating results from years where it is available. The carbon-specific emission goal is estimated by using historical data on the share of total GHG emissions derived from carbon emissions.

[2] Power generation adjustments include higher levels of electrification, the retirement of fossil-fuel plants, the addition of renewable resources, additional energy efficiency, and a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

[3] Electrification assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. It also assumes 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

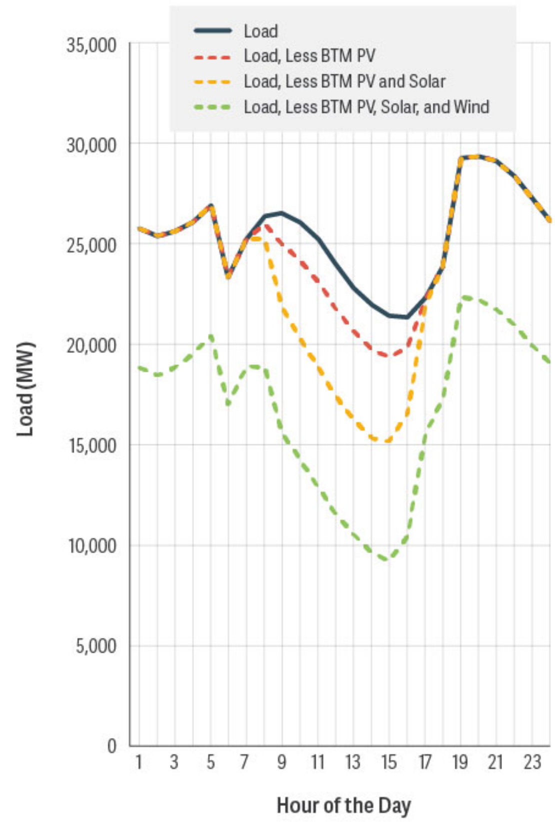
Finally, the substantial level of electrification assumed in the analysis would not be possible without adequate and flexible electric sector resources to reliably manage increased hourly net load variability over time. Figure ES-5 shows how the combination of greater variable renewable resources and the addition of electric vehicle and residential heating loads affects the average hourly "ramping" requirements on a representative winter day, which is projected to exceed 15,000 megawatts (MW) over very short time periods on particular days. Moreover, at the levels of electrification we assume, the addition in particular of new heating load shifts the annual peak from summer to winter months before the end of this decade (see Section III). Even assuming a significant quantity of technologically-feasible energy storage resources, the availability of existing fossil fuel generators will be vital over at least the next one to two decades for ISO-NE to manage the change in load

[8] The very small projected increase in CO_2 emissions for the electric sector in 2035 corresponds to 5,600 GWh of gas fired generation; 3% of the projected 185,700 GWh of electricity demand in 2035. This translates into approximately 40 BCF of natural gas consumption that could be offset by renewable natural gas and hydrogen substitution.

shape and growth in daily ramping requirements if the states are to achieve sufficient reductions in GHG emissions on a path to 2050 standards.

Observations

Figure ES-5: Representative Daily Net Load Variability
January 2035



It is obvious that establishing enhanced carbon pricing in electric energy markets is not an easy path to take from political and regulatory perspectives. Nor is coming to agreement on any other mechanism with the same objective in wholesale markets. For many years, New England wholesale electricity market stakeholders have pursued additional market-based designs to compensate low-carbon resources for the value that states implicitly place on this attribute, with no success. New England's wholesale markets as designed will not come close to providing the revenue needed to support investment in the resources required to meet the states' aggregate GHG reduction objectives. However, recent and projected declines in renewable resource costs, in combination with an effective carbon price, will provide a market design that can be relied upon by investors to support future investment in resources without relying on subsidization.

For more than 20 years, New England has embraced a competitive power market framework to guide stakeholder investment decision making in the power sector, and remove investment risk from captive ratepayers. Competitive wholesale power markets transformed New England's electric resource supply mixture, producing a cleaner, more efficient mixture of capacity resources and accompanying reduction in electric sector carbon intensity. Electricity consumers have not faced the risk of bearing any potential stranded costs associated with these thousands of megawatts of newer resources as merchant investors optimized the financial structures of these investments based in part on the region's durable wholesale market design. Ensuring a market design that can support the future investment in renewable resources can again shield captive ratepayers from these costly risks and usher in the next wave of electric resource development. Moreover, states in the New England region have relied for decades on market-based mechanisms and emission trading programs for control of sulfur dioxide, nitrogen oxide, and carbon dioxide emissions; effective carbon pricing simply builds upon the success of market-based programs.[9] After analyzing our modeling results and assessing the region's history with competition and emission control programs, we conclude that implementation of carbon pricing in the electric sector can be a vital tool supporting the states' achievement of decarbonization targets at the lowest possible cost, while preserving and enhancing the benefits of wholesale market competition for New England's electricity consumers.

[9] See *US EPA Acid Rain Program*, https://www.epa.gov/airmarkets/acid-rain-program; *US EPA NOx Budget Trading Program*, https://www.epa.gov/airmarkets/nox-budget-trading-program; and *The Regional Greenhouse Gas Initiative*, https://www.rggi.org/rggi-inc/contact.

It is critical that we not lose sight of the inefficiencies that can result if the power markets cannot provide opportunities for all resources to earn equitable returns of and on capital investment and recover ongoing fixed operational and maintenance costs, driving New England states (either individually or through ISO-NE) to contract individually with capacity resources. Analysis shows that the impending addition of several thousand megawatts of large-scale renewable resources in New England will put downward pressure on wholesale energy prices as the frequency of zero-price energy hours grows. This not only reduces revenues for existing resources needed to maintain reliability, but also undermines the longer-term financial prospects for the increased quantities of renewable resources entering the marketplace – resources that will eventually become existing resources. Moreover, as technology rapidly evolves, the risk of contracting with resources that quickly appear uneconomic grows, along with the risk of stranded investments. Ultimately, this scenario could lead toward inefficiencies and potentially increased costs for consumers, who bear the risks of out-of-the-money power projects, which are the very costs and risks that competition was intended to replace.

Finally, electricity consumers benefit from more efficient power pricing. Shifting the energy demand for transportation and residential heating from fossil fuel sources to electricity results in a significant change in consumers' expenditures for electricity. The electricity bill will become a more significant focus for consumers, potentially increasing the possibility that more consumers will respond to electricity price signals and adopt new technologies to minimize electricity costs. In this context, including an explicit price on GHG emissions in the electricity market will better align consumer choices with the societal benefits of reducing GHG emissions.

Below we highlight several additional observations related to the power system modeling analysis and the benefits of carbon pricing in the context of New England states' decarbonization efforts.

Immediate adoption of a carbon pricing mechanism in New England can provide many benefits for managing, and minimizing the cost of, a difficult transition to a decarbonized economy. Putting a price on electric sector emissions of pollutants is not new; it has a long history of successfully guiding industry transitions to lower-emission outcomes at the lowest possible cost to consumers. It is widely accepted that implementation of market-based emission control programs has dramatically lowered the cost of meeting more stringent ambient air quality standards.[10]

[10]See for example the SO_2 emissions reductions achieved as part of the cap and trade implemented as part of the 1990 Acid Rain Program: "The goal of Title IV of the Clean Air Act amendments of 1990, the Acid Rain Program, was to slash annual SO_2 emissions by 10 million tons from the 1980 baseline (26 million tons).… Between 1990 and 2004, SO_2 emissions from the power sector fell 36%, even as output from coal-fired power plants increased by 25% over the same period. The 8.95 million ton cap was reached in 2007. In 2010, by which time the cap and trade system had been augmented by the George W. Bush administration's Clean Air Interstate Rule, SO_2 emissions had fallen to 5.1 million tons." Justin Gerdes, "Cap and Trade Curbed Acid Rain: 7 Reasons Why It Can Do the Same For Climate Change," Forbes, February 13, 2012, available at https://www.forbes.com/sites/justingerdes/2012/02/13/cap-and-trade-curbed-acid-rain-7-reasons-why-it-can-do-the-same-for-climate-change/#4211a96d943a.

In addition to the observed emissions reduction success of the program, a retrospective review was conducted of the cost effectiveness of the program. The report discussed "how the costs of achieving environmental objectives through cap and trade compare with those of a 'counterfactual' (hypothetical alternative) command-and-control regulatory approach…. In addition to being less costly than traditional command-and-control policies would have been, the program's costs were significantly below estimates generated by government and industry analysts in the debate leading up to the passage of the CAA. In 1990, the U.S. Environmental Protection Agency (EPA) estimated the cost of implementing the Acid Rain Program (with allowance trading) at $6.1 billion. In 1998, the Electric Power Research Institute (EPRI), an industry organization, and Resources for the Future (RFF), an independent think tank, estimated that total implementation costs would be $1.7 and $1.1 billion respectively (based in part on actual figures for the first few years of the program …). … In sum, the SO_2 allowance-trading system's actual costs, even if they exceeded the cost-effective ideal for a cap-and-trade system, were much lower than would have been incurred with a comparable traditional regulatory approach, and were much lower than the trading system's predicted costs. There is broad agreement that the SO_2 allowance-trading system provided a compelling demonstration of the cost advantages of a market-based approach." Gabriel Chan, Robert Stavins, Robert Stowe, and Richard Sweeney, *The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation*, National Bureau of Economic Research Working Paper No. 17845, February 2012, available at https://www.nber.org/papers/w17845.

Given the magnitude and pace of GHG emission reductions required in the coming decades, a transparent price on carbon emissions can help smooth what may otherwise be a difficult transition. In a seamless way, with government direction, but without government intervention, carbon pricing can efficiently move operational decisions and resource dispatch away from emitting resources, and help direct new electric sector investment dollars towards low-carbon sources of power. It will increase the value of reducing consumption, and can support levels of investment sufficient to fund both generating sources and the infrastructure needed to get distant resources to market. Carbon pricing has the potential to, in effect, "grease the skids," and reduce administrative and regulatory friction by the degree that is needed for development of sufficient low/zero-carbon resources to meet states' standards.

Introducing a carbon price in the electric sector allows for technology-neutral competition among both existing and new zero-emission resources, providing incentives to minimize costs and pursue innovation. The following benefits can be expected from introducing carbon pricing: (1) providing a durable market-based incentive that can bring forth and maintain zero-carbon resources to meet New England GHG reduction targets; (2) reducing reliance on out-of-market contracts that lock in long-term costs for consumers and may prevent the rapid adoption of unforeseen technological advances; (3) increasing the opportunity for financing of clean energy resources in the absence of long-term contracts;[11] (4) increasing incentives for entrepreneurs and others to develop new supply-side and demand-side technologies, products, and services; (5) influencing consumer access to and use of demand-management technology and practices; and (6) seamlessly complementing other state policies by providing a means to value carbon investment in the electric system.

The commitment to a durable market attribute that appropriately incorporates the cost of carbon allows all resources to compete and ensures not only that zero-emission resources are compensated equitably, but that all other resources whose production is needed to ensure reliable system operations are compensated equitably. Existing zero-emission resources – whether nuclear, hydroelectric, or more recently added renewable resources with shorter asset lives – will be appropriately compensated for the zero-emission attributes of their resources. When evaluating investments, lenders can rely on a transparent wholesale energy price that values the social costs of carbon and provides a relatively stable future revenue stream. At the same time, the benefits that the addition of new zero-cost resources provides to consumers through lower market prices are still realized, while the recovery of the capital investments and ongoing operating costs need not be guaranteed by captive retail consumers.

The introduction of a carbon price in the power sector would increase wholesale electricity prices, but would not drive up consumer costs materially if states choose to rebate carbon revenues. Our analysis shows that as a carbon price is introduced, it will logically cause wholesale electricity prices to rise as fossil fuel generators add that cost to their energy market offers. The increased price, however, does not need to translate to materially higher consumer costs. Consumers can be compensated to offset the impact of energy price increases using the carbon revenues collected from fossil fuel generators. Recent studies have assessed a number of rebate mechanism designs that can equitably redistribute carbon revenues to consumers.[12] While the exact design and redistribution principles are beyond the scope of this report, New

[11] Providing a durable carbon pricing mechanism will provide finance markets a basis upon which to evolve and create hedging instruments that can alleviate the need for state-mandated long-term contracts. See, for example, WindEurope, *The value of hedging: New approaches to managing wind energy resource risk*, November 2017.

[12] See, for example, Marc A.C. Hafstead, Wesley Look, Amelia Keyes, Joshua Linn, Dallas Burtraw and Roberton C. Williams III, *An Analysis of Decarbonization Methods in Vermont*, Resources For The Future, January 2019. See also Lawrence H. Goulder, Marc A. C.

England states would be able to recover a significant amount of the revenue collected through a carbon price and return it to electricity consumers through financial mechanisms that retain the improved incentives of market prices incorporating a cost for CO_2 emissions. Moreover, the efficiency and value of electrification of transportation and residential heating could actually lower all-in energy consumption costs for consumers over time.

Analysis demonstrates that carbon pricing can establish a market-based, efficient mechanism to drive investment in resources needed in New England, and remove the need for separate state-mandated procurement of low-carbon resource investment. The absence of an effective carbon-pricing mechanism is a fundamental challenge to continued reliance on competitive markets for efficient addition and attrition of power system resources. Markets (even including a Regional Greenhouse Gas Initiative (RGGI) price) currently fail to capture attributes essential to meeting the New England states' aggregate economy-wide GHG reduction goals. Absent adoption of a carbon price in energy markets, the pace and magnitude of additions of out-of-market, procurement-based resources will likely undermine the continued relevance of wholesale markets in New England as a vehicle for resource development and investment. The ideal pathway to decarbonization is one that both succeeds in meeting state GHG standards *and* does so at least cost through the operation of competitive wholesale electricity markets. Carbon pricing in energy markets is not an easy path to take, but it may be the only one that can preserve the operation of competition for the benefit of consumers.

Hafstead, GyuRim Kim, and Xianling Long, *Impacts of a Carbon Tax across US Household Income Groups: What Are the Equity-Efficiency Trade-Offs?* National Bureau of Economic Research Working Paper No. 25181, October 2018.

II. Introduction

The New England states have made substantial commitments to reducing GHG emissions on an expedited schedule. The states are motivated by a sense of urgency to address and reduce the risks of climate change, an urgency that is reflected in the standards and timelines they have adopted. There is little doubt that meeting the standards will require an unprecedented magnitude and pace of change in how the region produces and consumes energy for electricity, transportation, residential heating, and other uses.

How states will meet their GHG reduction standards is, at this point, only loosely defined. But it is widely accepted that electrification of the transportation and heating sectors, in tandem with deep decarbonization of the electric system, will play a central role.[13] In fact, in addition to the GHG reduction standards presented in Table 1, the states have administered a wide array of complementary regulations and policies focused on the electric industry to help accelerate the development and commercialization of distributed and grid-connected hydro, wind, solar, storage, and other technologies – resources and technologies that will be essential to meet the GHG reduction targets.

Table 1: Historical and Expected New England State Economy-Wide Greenhouse Gas Emissions ($MMTCO_2e$)[14]

	Historical Emissions		Standards
	1990	2015	2050
Connecticut	45.3	43.8	9.9
Massachusetts	94.4	76.1	18.9
Maine	21.7	19.1	4.3
New Hampshire	15.8	17.0	3.2
Rhode Island	12.5	11.3	2.5
Vermont	8.6	10.0	1.7
Total	**198.2**	**177.3**	**40.5**

Notes:

[1] The emissions reduction goals by state are as follows:

- Connecticut: 10% by 2020 below 1990 levels; 45% by 2030 and 80% by 2050 below 2001 levels.
- Maine: 10% by 2020, 45% by 2030, and 80% by 2050 below 1990 levels.
- Massachusetts: 25% by 2020 and 80% by 2050 below 1990 levels.
- New Hampshire: 20% by 2025 and 80% by 2050 below 1990 levels.
- Rhode Island: 10% by 2020, 45% by 2035, and 80% by 2050 below 1990 levels.
- Vermont: 40% by 2030 and 80% by 2050 below 1990 levels.

[2] The goals for all states except New Hampshire are legislated/signed into state law. An 80% reduction in Maine is assumed based on other state emission standards.

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[13] Motor vehicle manufacturers have made commitments to produce growing numbers of light-duty battery electric vehicles and some expect that consumers will see cost parity (varying by location) relative to gasoline vehicles by the middle of this decade (Cite: BloombergNEF, Electric Vehicle Outlook 2020, https://about.bnef.com/electric-vehicle-outlook/ and IEA (2019), *Global EV Outlook 2019*, IEA, Paris at https://www.iea.org/reports/global-ev-outlook-2019).

[14] Sources: [1] Connecticut Department of Energy & Environmental Protection, *Connecticut Greenhouse Gas Emissions Inventory*, 2016. [2] Massachusetts Department of Environmental Protection, *Statewide Greenhouse Gas Emissions Level: 1990 Baseline and 2020 Business As Usual Projection, Regulatory Authority: MGL Chapter 21N, Section 3*, July 1, 2009. [3] Maine Department of Environmental Protection, *Report to the Joint Standing Committee on Environment and Natural Resources, 128th Legislature, Second Session, Seventh Biennial Report on Progress toward Greenhouse Gas Reduction Goals*, January 2018. [4] New Hampshire Department of Environmental Services, *New Hampshire*

The states' GHG reduction standards identify a destination, but reveal little about the *pathway*. Yet the path the region takes to the decarbonized end-state could be the most important driver of the cost, technological, and reliability challenges customers and industry stakeholders will face along the way. The transformation will require deep and continuous investments in transportation, building, and power system infrastructure, and will accelerate the development and commercialization of a wide array of energy-related technologies and services. It will also fundamentally transform the location, size, fuel needs, and operational characteristics of the power supply infrastructure used to keep the lights on.

No one can suggest that they know what the region's energy systems will look like at the endpoint, 30 years from now; far too much will change – in technology development, resource and infrastructure costs, and consumer actions – that will affect both producers and consumers, and that will alter the path to decarbonization along the way. But much can be gained by thinking carefully about how to manage the starting point – that is, the next 10 to 15 years – in mapping a pathway to reasonable progress, and reflecting current energy system circumstances, practices, and technologies.

In this context, the proper pricing of goods and services, including a price on carbon and emissions of CO_2, could be essential to guide the states through a challenging transition in a manner that maintains reliability, encourages efficiency, fosters innovation, and minimizes the cost to society to meet the GHG reduction mandates.[15] There is wide agreement among economists and policy analysts that carbon pricing would be a key component of a cost-effective policy to materially reduce carbon emissions.[16] The introduction of a multi-sector carbon price would provide consumers with an important indication of the costs associated with carbon emissions, and reduce consumer demand for carbon-based fuels across all sectors. We recognize, however, that regional carbon pricing on its own is likely to be insufficient to achieve reductions in CO_2 emissions commensurate with state mandates in sectors such as transportation and heating.[17] In part for this reason, analysts and policy makers have focused on the potential for electrification of transportation and building end uses, in combination with decarbonization of the electric sector, as an economic pathway to deep reductions in GHG emissions.

A meaningful multi-sector price on carbon could both help drive the investments in the electric sector necessary to support electrification and provide an important price signal to facilitate reductions from other sectors. This is particularly true in ensuring that emissions valuation largely remains consistent across sectors. Without a multi-sector approach, the financial signal needed electrification in transportation or

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Greenhouse Gas Emissions Inventory, 2016. [5] Rhode Island Department of Environmental Management, *Rhode Island Greenhouse Gas Emissions Reduction Plan*, December 2016. [6] Vermont Department of Environmental Conservation, *Vermont Greenhouse Gas Emissions Inventory Update: Brief 1990-2015*, June 2018.

[15] See, for example, Kennedy, J., *How Induced Innovation Lowers the Cost of a Carbon Tax*, Information Technology and Innovation Foundation, June 2018, noting how carbon pricing: "has two particular effects: boosting efficiency in the activities that emit carbon (e.g., using more fuel-efficient motors), and accelerating development of cleaner technologies that are also cheaper. Firms have a greater incentive to become more energy efficient and switch to less carbon-intensive fuel, while consumers have a similar incentive to buy fewer carbon-intensive or more fuel-efficient goods. And technology developers have a stronger incentive to invest in clean energy technologies," p. 5.

[16] See, for example, Robert N. Stavins, *The Future of U.S. Carbon-Pricing Policy*, Harvard Kennedy School, M-RCBG Faculty Working Paper Series No. 2019-02, pp. 2–3.

[17] Recent studies estimate that applying carbon pricing to the transportation and heating sectors could reduce CO_2 emissions by 10–20% in a given year; however, to meet state mandates requires far greater annual reductions (2–3 times higher than these studies' estimates). See, for example, Marc A.C. Hafstead, Wesley Look, Amelia Keyes, Joshua Linn, Dallas Burtraw, Roberton C. Williams III, *An Analysis of Decarbonization Methods in Vermont*, Resources for the Future (RFF), January 2019, pp. 3–4 and p. 101, showing reductions of 13–19% below 2005 levels in 2025. See also Marc Breslow Ph.D., Sonia Hamel, Patrick Luckow. and Scott Nystrom, *Analysis of a Carbon Fee or Tax as a Mechanism to Reduce GHG Emissions in Massachusetts*, prepared for the Massachusetts Department of Energy Resources, December, 2014, pp. 13–14, showing annual reductions of 10–20% below 2013 levels in 2025-2040. While these studies focus on individual states, the RFF study applies carbon pricing to the entire New England region and the similar range of findings is indicative of similar percentage reductions region-wide.

residential heating would be undermined because CO_2 emissions have only been valued in the electricity sector.

Ironically, both the steady reductions over the past couple of decades in electric sector CO_2 emissions and ongoing state resource procurements have limited consideration of the potential benefits that could be obtained on a going-forward basis through establishing an effective price on CO_2 emissions for the electric sector. In the current context, recognizing that electrification of the transportation and heating sectors will be critical to meet state GHG reduction objectives and fundamentally alter the level and shape of electricity demand, the potential benefits of enhanced market-based CO_2 emission pricing should not be overlooked.

This report focuses primarily on the outsized role of the power sector in achieving GHG reductions through changing resource mix and electrification of the transportation and residential heating sectors, and asks the following questions:

- What do scenarios for the transition suggest about the resources and infrastructure that need to be retained and added, those that may be retired, and how such investment and retirement decisions could be affected by efficient carbon pricing?
- What carbon price levels are sufficient to drive investment in low/zero-carbon resources and the efficient transformation of energy sector infrastructure?
- How will carbon pricing affect suppliers and consumers of electricity, and what does this imply for changes in production and consumption decisions?
- What are the key uncertainties to monitor as the region moves forward?

Our analysis is intended to inform ongoing efforts in the New England region to align states' climate policies with their economic and consumer protection goals. A few decades ago, most New England states adopted retail and wholesale competition in the electric industry to foster technical innovation, remove investment risk from consumers, capture operational and financial efficiencies in generation, and minimize the costs of generating and consuming electricity. Over that period, consumers have benefited from the operation of wholesale markets through increased operational efficiency and placing the risk of capital investment not on electricity consumers, but on the market entities best equipped to manage and absorb them – such as developers, banks, and independent power suppliers.

However, current market incentives are at odds with the GHG emission reduction goals of the New England states. Wholesale markets simply do not value reduction of GHG emissions to the level implied by the current laws, policies, and goals of the states. Consequently, the market is not producing the resources needed to meet those goals. Conversely, states have taken matters into their own hands, and are actively administering procurements for low/zero-carbon resources in a way that currently compromises the workings of wholesale markets and will increasingly do so.

Given the outsized role the electric sector will have over the coming decades in meeting states' GHG emission-reduction objectives, pricing carbon in electricity market transactions has the potential to bridge this gap. In this report we evaluate the potential risks associated with rapid transformation of energy supply and use, and investigate the potential role of carbon pricing to help bridge the gap between state climate policy and the operation of wholesale markets.

In Section III we summarize the key results of the modeling analysis. In Section IV we present the observations and conclusions we draw from the evaluation of decarbonization pathways, our review of the implications, and the modeling of impacts with and without use of a price of carbon in electricity markets. Finally, we provide a Technical Appendix in which we summarize the current status of state policy and the literature relating to decarbonization, and explain our modeling analysis assumptions in greater detail.

III. Modeling Results

The results of our modeling analyses combine output from the Enelytix security-constrained unit commitment and hourly dispatch model[18] for the ISO-NE electricity sector with electrification models that simulate changes in gasoline consumption, heating fuels, electricity demand, and GHG emissions stemming from electrification of the transportation and residential heating sectors. Based on our review of decarbonization literature and the steps the New England states are beginning to take to accelerate the adoption of electric transportation and residential heating, we develop three scenarios for making reasonable progress towards meeting the New England states' GHG emission reduction standards based on the combination of electrification and electric sector decarbonization. Specifically, our analysis includes and analyzes the following three scenarios over the next 15 years through snapshots of each five-year period (2025, 2030, and 2035).

- ***Baseline*** – The baseline scenario is the starting point for the analysis, and represents conditions currently forecast for demand and resource changes absent either significant electrification of the transportation or residential heating sectors, or accelerated decarbonization of the electric sector.
- ***Low Electrification/Contract Resources (LECR)*** – The LECR scenario increases electrification of light-duty vehicles (LDVs) and residential heating systems relative to the baseline scenario. Under the LECR scenario we assume that a set percentage of LDVs and residential heating systems will switch from fossil fuel inputs to electricity: (1) 12.5% (2025), 17.5% (2030), and 30% (2035) of residential homes currently heating with oil, propane, or natural gas switch to electric heating; and (2) 25% (2025), 35% (2030), and 60% (2035) of consumers driving LDVs switch to electric vehicles. The LECR scenario also includes significant additions of solar, wind, and hydro resources resulting from existing and expected state procurements.
- ***High Electrification/Carbon Pricing (HECP)*** – The HECP scenario increases electrification of LDVs and residential heating systems relative to the LECR scenario, and includes significant accelerated decarbonization of the electric sector driven by the development and addition of major low/zero-carbon resources responding to the CO_2 prices identified in this report. The HECP scenario assumes: (1) 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with oil, propane, or natural gas switch to electric heating; and (2) 25% (2025), 60% (2030), and 90% (2035) of consumers driving LDVs switch to electric vehicles. It also involves the addition of major solar, onshore wind, offshore wind, hydro/renewable, and storage resources above and beyond those included due to state contracting in the LECR scenario.

For each of our electrification scenarios we evaluate the capacity resource mix that would be available to meet the projected increase in electricity peak demand and energy consumption. Table 2 summarizes the resource mixes relied upon in the modeling scenarios.

[18] Enelytix, Newton Energy Group LLC and Polaris Systems Optimization, Inc.

Table 2: Modeling Resource Mixtures (MW)[19]

Summary of Capacity (MW) Assumptions Used In the Low and High Electrification Scenarios
ISO New England

	Low Electrification/Contract Resources (LECR)			High Electrification/Carbon Pricing (HECP)		
	2025	2030	2035	2025	2030	2035
Existing Derated Capacity After Retirements (Excludes BTM PV)	28,818	29,895	30,923	28,818	30,465	32,543
Assumed Additions (Derated Capacity)						
Battery Storage Additions	50	250	700	50	250	2200
Onshore Wind Additions	0	182	0	0	182	182
Additional Renewable Resources Distant from Load	0	0	0	0	0	1090
Offshore Wind Additions	1020	480	0	1020	960	0
Installed Capacity (Derated Capacity)	**29,895**	**30,923**	**31,623**	**30,465**	**32,543**	**36,585**
Imports	1,188	1,188	1,188	1,188	1,188	1,188
Total Capacity	**31,083**	**32,110**	**32,810**	**31,653**	**33,730**	**37,772**
Assumed Behind-the-Meter PV and Energy Efficiency						
Behind-the-Meter PV	950	1,183	1,392	950	1,183	1,392
Energy Efficiency in Peak Hour	5,519	6,725	8,477	5,982	8,292	10,311

Notes:
[1] Capacity represents the total existing capacity at the start of each year prior to adding additional resources. Onshore wind, offshore wind, and solar capacity is derated at factors of 26%, 30%, and 28.5%, respectively. For additional detail, see source [B].
[2] Existing capacity as of 2025 includes approved renewable resource additions and expected or at-risk unit retirements of approximately 5,500 MW of capacity of aging coal-, oil- and gas-fired generation stations.
[3] Between 2019 and 2025, 5,238 MW of capacity is expected to come online. These additions include approved offshore wind, the Canadian Interconnection, and others.
[4] Import capacity is obtained from the 2019 CELT Report.
[5] The *2016 Act to Promote Energy Diversity* directed Massachusetts electricity distribution companies to procure 1,600 MW of offshore wind by 2027. In May 2018, it was announced that the 800 MW Vineyard Wind project had been selected. The *2018 Act to Advance Clean Energy* authorizes state officials to procure an additional 1,600 MW by 2035. See sources [C], [D], and [E].
[6] In June of 2019, the Connecticut state government passed *An Act Concerning the Procurement of Energy Derived from Offshore Wind* which enabled the Commissioner of Energy and Environmental Protection to issue solicitations totaling up to 2,000 MW. All 2,000 MW must be reached by the end of 2030. See sources [C], [F]
[7] In 2018, Rhode Island issued an RFP for 400 MW of offshore wind. In May 2018 it was announced they had selected Deepwater Wind's 400 MW Revolution Wind Project. See sources [C], [G].

The magnitude of electrification needed to meet the states' GHG reduction standards is significant, and will need to occur over a relatively short time frame. Consequently, we evaluate the peak demand impact of the increased electrification scenarios to confirm that the growth in electrification could be accommodated by the assumed resource mixes. Figure 1 shows the projected change in peak demand due to electrification, with two primary implications for future electric system hourly demand shapes. First, the charging pattern of LDV electric vehicles (EVs) is likely to introduce large hourly load increases in the evening hours. Second, the major increase in electric heating and EV penetration will substantially increase base load during the winter months, eventually shifting the system peak demand from summer to winter. As Figure 1 shows, the growth in the winter peak demand is substantial; even with aggressive additions of renewable resources the shift points to the ongoing need for existing fossil fuel resources and natural gas infrastructure to remain available and operational for decades, supporting reliable New England power sector operations as the region achieves aggressive reductions in GHG emissions.[20]

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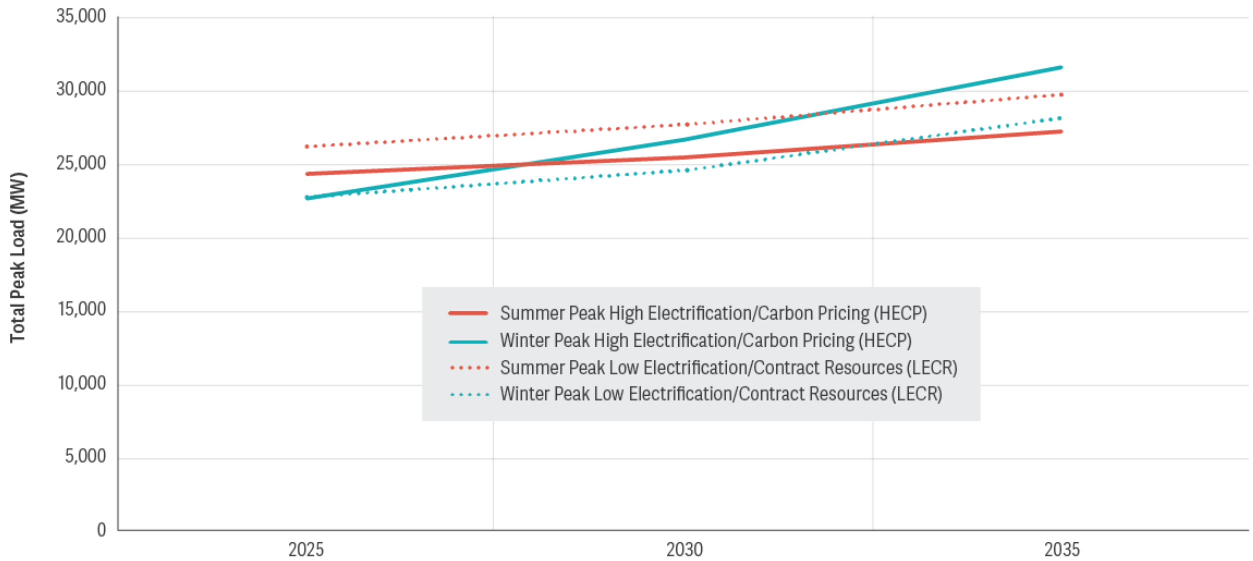
[19] Sources: [A] ISO New England, *New England's Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT Report), 2019. [B] ISO New England, *2016 Economic Study: NEPOOL Scenario Analysis*, July 24, 2017. [C] *Public Policy Center UMass Dartmouth, U.S. Offshore Wind Project Pipeline*, accessed at: http://publicpolicycenter.org/osw-project-pipeline-in-the-states/#toggle-id-5. [D] Massachusetts Legislature, *An Act to Promote Energy Diversity, Chapter 188, 2016, accessed at: https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188. [E] Massachusetts Legislature, An Act to Advance Clean Energy, Chapter 227*, 2018, accessed at: https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227. [F] *Massachusetts Department of Energy Resources, Request for Proposals for Long-Term Contracts for Offshore Wind Projects*, May 23, 2019, accessed at: https://macleanenergy.files.wordpress.com/2019/05/83c-ii-rfp_finalpackage.pdf. [G] Connecticut Legislature, *An Act Concerning the Procurement of Energy Derived from Offshore Wind, Substitute House Bill No. 7156, Public Act No. 19-71*, accessed at https://www.cga.ct.gov/2019/ACT/pa/pdf/2019PA-00071-R00HB-07156-PA.pdf.

[20] Our analysis focuses on the starting point set of resources and decarbonization options that appear practically achievable based on current information. We acknowledge that this could change if there is a breakthrough in ubiquitous and economic energy storage or an

Figure 1: Annual Peak Load by Season and Electrification Level



Notes:

[1] The low electrification scenario assumes 12.5% (2025), 17.5% (2030), and 30% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. The low electrification scenario also assumes 25% (2025), 35% (2030), and 60% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

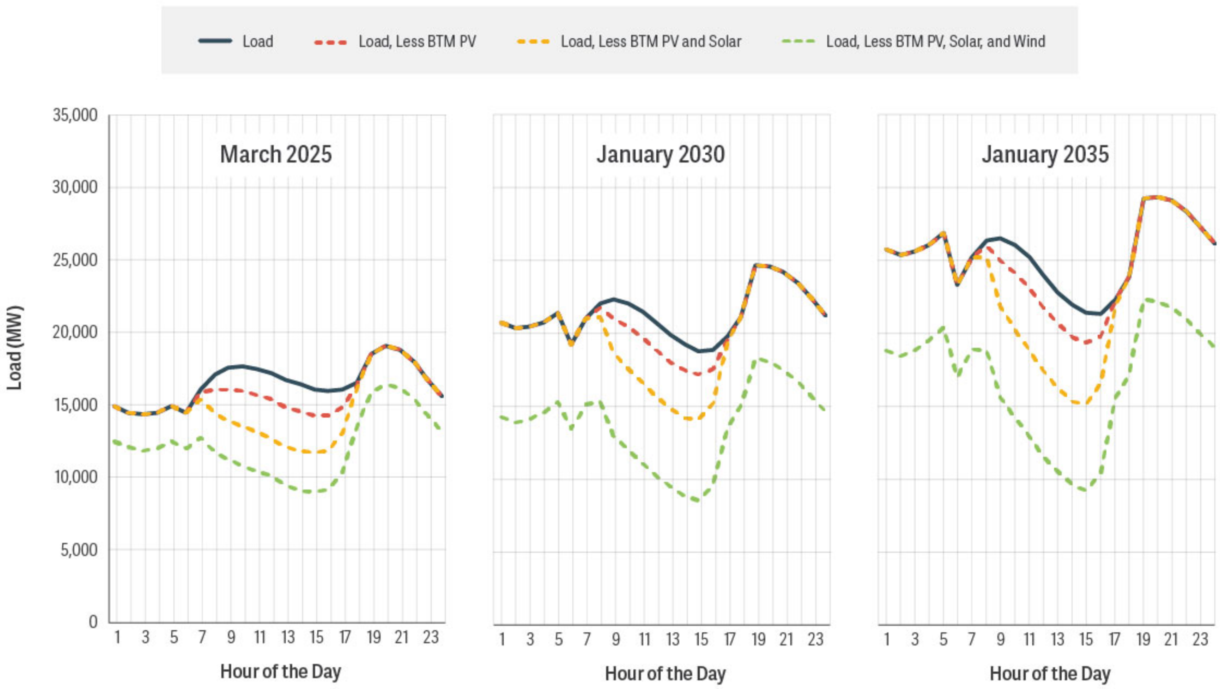
[2] The high electrification scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. The high electrification scenario also assumes 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. The high electrification plus scenario is incremental to the high electrification scenario. It assumes additional EE (25% increase over assumed 2035 EE), and adds additional renewable resources to bring power sector emissions down by 50% relative to the high electrification case power sector emissions.

[3] The winter peak is the coincidental peak load for January, February, and March after netting out behind-the-meter solar and adding electrification load. Similarly, the summer peak is the coincidental peak load for June, July, and August after netting out behind-the-meter solar and adding electrification load.

The second important element of electrification relates to the increase in net load variability (net load is equal to total system load minus solar and wind-powered generation resources). As electrification increases, there will be hour-to-hour load variations that will require thousands of megawatts of resources available to ramp up and down over very short periods of time to accommodate changes in net load. For example, Figure 2 shows that estimates of system ramps will progressively grow from several thousand megawatts in 2025 to between 10,000 and 15,000 MW in 2035, depending upon both renewable energy production patterns and EV charging schedules. It is clear that a significant quantity of flexible generation resources will be necessary to accommodate the large variations in net load. In addition, as usage of the electric system evolves to support decarbonization, retail rate structures may need to evolve substantially to provide incentives for usage patterns that help mitigate or address the growing system ramping requirements.

alternative fuel source (e.g., hydrogen). However, absent significant technological change, the need for the region's infrastructure remains an important element of an economic transition and reliable system operations.

Figure 2: Average Ramp-Ups for the Month that the Peak Ramp Occurs
High Electrification – Winter Season



Note:
[1] The reported months are those in which the maximum ramp-up net of renewables occurs.

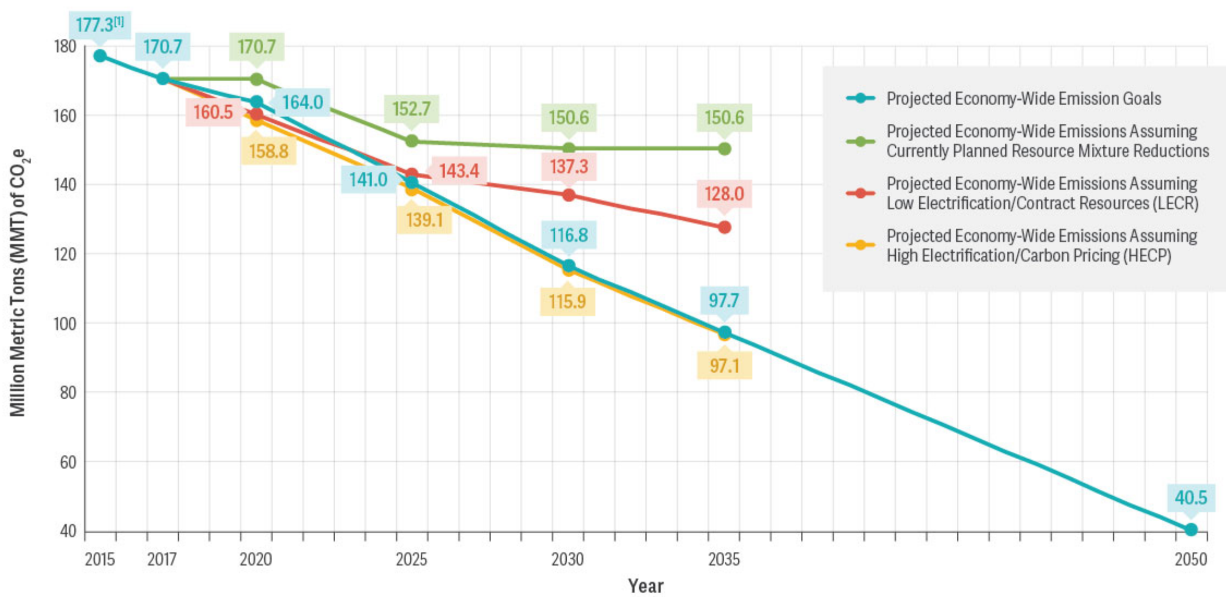
As noted, there are three scenarios developed to explore the implications of practical pathways to achieve the states' GHG reduction objectives: the Baseline scenario, the Low Electrification/Contract Resources (LECR) scenario, and the High Electrification/Carbon Price (HECP) scenario. For each scenario we model the dispatch of the ISO-NE electricity system using the Enelytix hourly dispatch model. The model simulates the impact of changes in the capacity resource mix and increased demand from electrification, taking into account the day-ahead unit commitment required to meet the daily hourly loads.[21] For each of the modeling scenarios we project changes in GHGs in equivalent CO_2 emissions ($CO_{2\text{-}e}$), energy prices, generation resource mix, and revenues.

The results of our analyses are presented in the tables and figures below. We first present how each scenario affects the pathways for GHG emission reductions for New England. We next show how the generation resource mix changes given the shifts in resource mix needed to make reasonable progress towards meeting the states' GHG reduction targets. We present implications of the analysis for setting a price on CO_2 sufficient to support future investment in the quantity of renewable resources needed to meet the states' aggregate targets. Finally, we show how the inclusion of a carbon price in the New England wholesale markets affects projected wholesale energy prices.

[21] The model commits a sufficient quantity of dispatchable generation resources to meet the projected daily hourly net load (demand) and operating reserves, but does not capture day-ahead to real-time forecast uncertainty that can impact intra-day ramping requirements.

Figure 3 presents the GHG emission reduction trajectories (in $CO_{2\text{-}e}$) for each modeling scenario. The pathway most consistent with reducing GHG emissions in line with New England's state standards requires significant electrification of the transportation and heating sectors, simultaneous with aggressive decarbonization of the electric sector. The results of these analyses show that only the HECP scenario is consistent with a pathway for meeting the region's standards. In 2025 we find that the combination of a large amount of renewable resource capacity additions and the start of increased electrification of residential consumer transportation and heating places the region on a path to reasonable progress. In 2030 and 2035, the HECP scenario-projected GHG emissions (116 million and 97 million metric tons) fall in line with projected regional GHG emission levels of approximately 117 million and 98 million metric tons, consistent with a trajectory to meet the long-term 2050 targets.[22] Because we find that our high-electrification scenario is necessary to achieve sufficient GHG emission reductions, we focus our discussion of results on this scenario.

Figure 3: Comparison of New England CO_2 Emission Reduction Standards with Power Sector CO_2 Emission Reductions from Planned Renewable Resource Additions and Increased Electrification Scenarios



Notes:

[1] In 2015, total GHG emissions across New England were 177.3 MMT of CO_2e (43.8 in CT, 76.1 in MA, 19.1 in ME, 17.0 in NH, 11.3 in RI, and 10.0 in VT).

[2] Economy-wide emission reduction goals are determined by aggregating each New England state's historical emissions and annual emission targets. If data is unavailable for a given year, the goal is estimated by interpolating results from years where it is available by state.

[3] Resource mixture adjustments include the retirement of fossil-fuel plants and the addition of renewable resources.

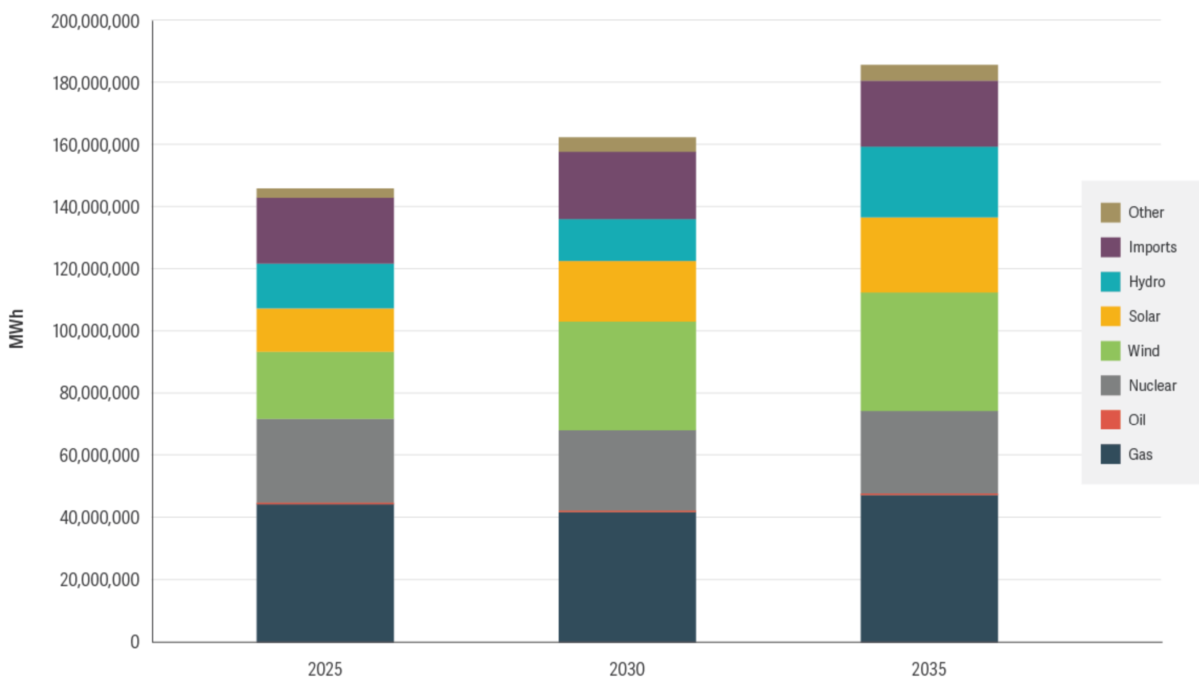
[4] The LECR scenario assumes 12.5% (2025), 17.5% (2030), and 30% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. The LECR scenario also assumes 25% (2025), 35% (2030), and 60% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

[5] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional energy efficiency (EE) at a 25% increase over assumed 2035 EE, and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

[22] The projected carbon dioxide emission levels we calculate fall within the range that have been reported in other analyses. See, for example, Northeast States for Coordinated Air Use Management (NESCAUM), *Greenhouse Gas Mitigation Analysis for New England: White Paper Policy Summary*, September 2018, p. 4.

Figures 4A and 4B report the modeling scenario generation mixes for the HECP scenario by production quantities and percentages. These Figures shows both the progressive increase in electricity production needed to support substantial growth in electrification, and the decarbonization of the generation resource mix required to meet this growth in a manner consistent with state targets. While the baseline electricity demand is projected to decline significantly over this period due to deployment of energy efficiency and distributed solar PV, this reduction is overwhelmed by the increased demand to meet the level of transportation and heating electrification needed to meet the states' GHG reduction requirements. While this progress rests on the back of substantial growth in electricity demand, the growth in renewable resources resulting from application of a price on CO_2 in power system operations leads to continuous declines in the system's CO_2 emission intensity, and only a small increase in electric sector GHG emissions, tied primarily to existing cycling resources that are needed to meet large ramping requirements. In short, the large reduction in GHG emissions from electrification dwarfs the residual emissions from remaining fossil-fueled generation resources (see Figure ES-3).

Figure 4A: Generation Mix – High Electrification

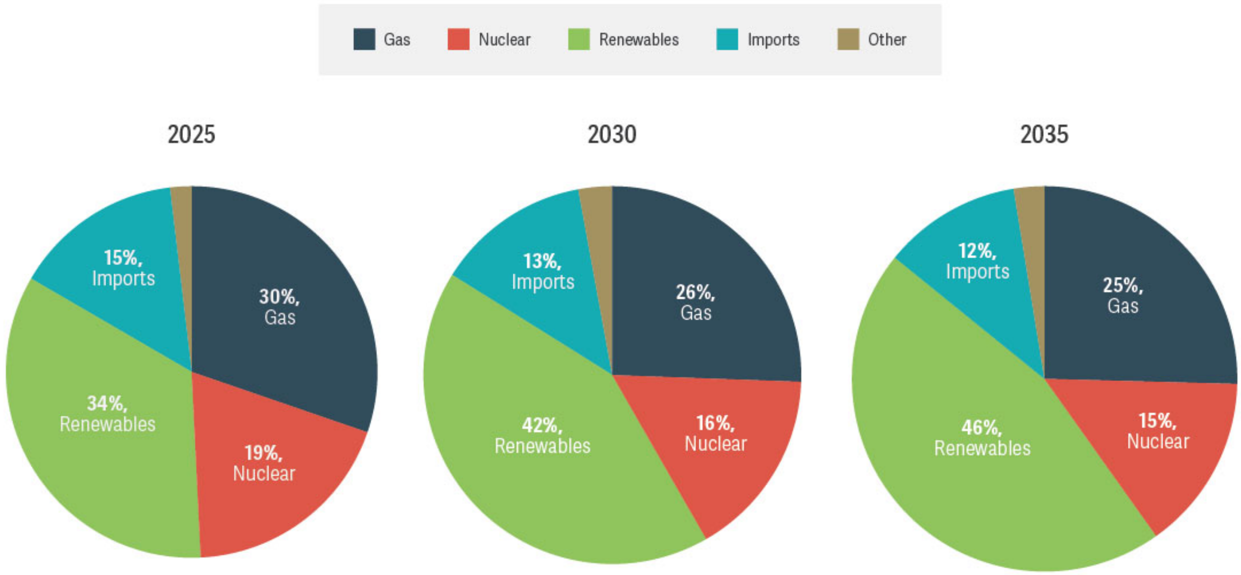


Notes:

[1] Imports = Imports between ISO-NE and HQ, independent of the New England Clean Energy Connect contract and imports/exports between ISO-NE and NYISO and NB. The NECEC contract appears in the Hydro category; Other = landfill gas, biomass, refuse. Solar includes both utility-scale and behind-the-meter.

[2] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional EE (25% increase over assumed 2035 EE) and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

Figure 4B: Generation Mix Percentage– High Electrification



Notes:

[1] Renewables includes hydro, wind, and solar generation.

[2] Oil generation makes up less than 0.001% of all annual generation and is not included in these charts.

[3] Imports = Imports between ISO-NE and HQ, independent of the New England Clean Energy Connect contract and imports/exports between ISO-NE and NYISO and NB. The NECEC contract appears in the Hydro category; Other = Landfill gas, biomass, refuse. Solar includes both utility-scale and behind-the-meter.

[4] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional EE (25% increase over assumed 2035 EE) and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

Figure 5 reports the range of implied carbon prices that we derive using the modeling results in the HECP scenario. In each of the three years we analyzed we identify the positive difference, where applicable, between estimated future renewable resource levelized costs and the projected energy and capacity market revenues. Our results reveal a range of carbon price levels dependent upon the type of renewable resource being evaluated, its future costs (both capital and financing), and the cost for the resource's transmission interconnection. On the one hand, utility solar and onshore wind resources would require lower (or no) carbon pricing, assuming continued modest cost declines and reasonable interconnection costs. On the other hand, our analysis consistently shows that offshore wind additions require additional revenue, and that the adoption of a power-sector carbon price in the range of \$55–70/short ton CO_2 by the year 2030 would be expected to make these investments economically viable without subsidization.

The estimated range of carbon prices captures the fact that in the near term (e.g., through 2025), the states have already made (or are in the process of making) contractual commitments for a number of renewable resources. This suggests that a lower value (in the range of \$25–35/short ton CO_2) would be a reasonable starting point, while still providing strong incentives for accelerated development of lower-cost renewable resources. In particular, utility-scale and community solar and onshore wind resources could approach economic viability at this level of carbon pricing, reducing significantly the need for state subsidization. In the latter two periods – 2030 and 2035 – there is significant uncertainty regarding the cost trajectories for more advanced renewable resources, especially offshore wind and incremental interconnection to access renewable resources distant from load. We report a fairly wide range of values in this time period, recognizing that a number of factors will affect the evolution of the offshore wind industry.

Figure 5: Implied Carbon Prices[23]

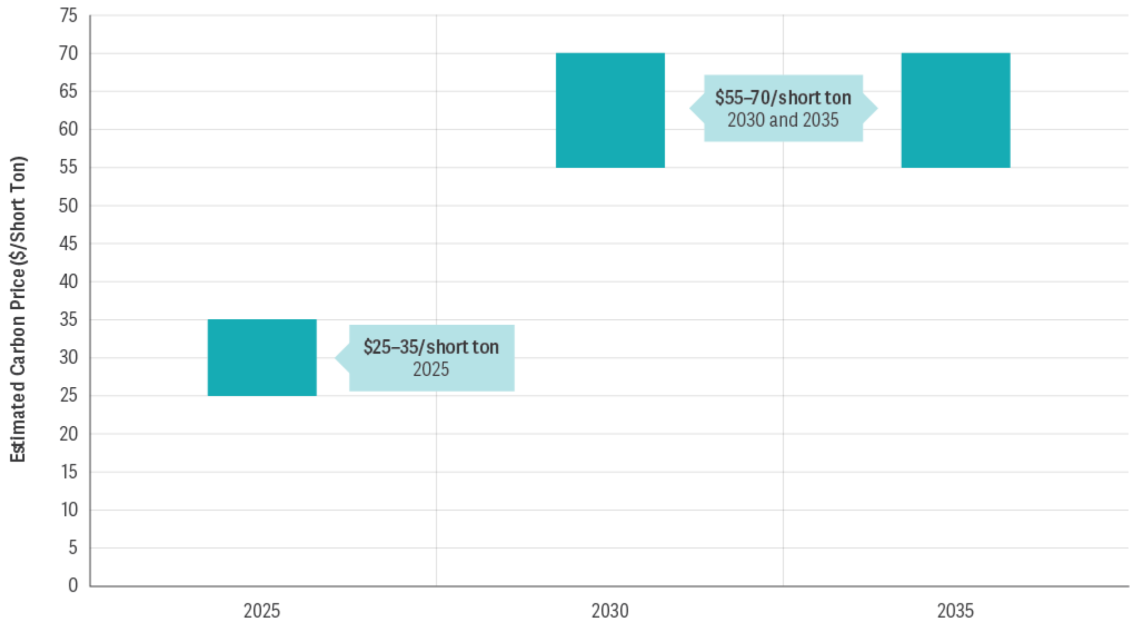
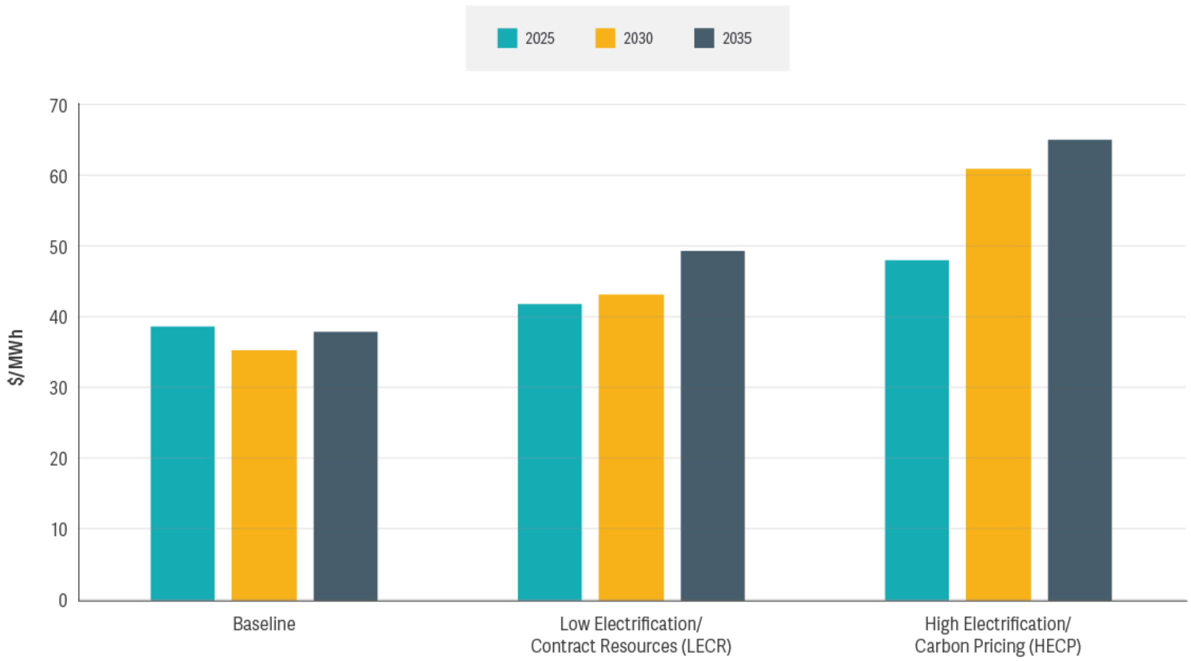


Figure 6 presents the average annualized locational marginal prices (LMPs) for each of the modeling scenarios assuming carbon prices of $25, $65, and $70/short-ton CO_2.[24] As expected, increased electrification puts upward pressure on electric energy prices. However, substantial growth in zero-marginal-cost renewable resources keeps prices relatively low, even with substantial growth in electricity demand. Aside from occasional short-term increases in prices in 2035, the primary change in energy prices is associated with the introduction of a carbon price in the modeling analysis. As Figure 6 shows, incorporating an implied carbon price in the modeling scenarios increases energy prices by approximately $7/megawatt-hour (MWh) in 2025, $20/MWh in 2030, and $20/MWh in 2035 (relative to the HECP scenario without a carbon price).

[23] Sources: [1] Lazard, *Levelized Cost of Energy Analysis – Version 13.0*, November 2019. [2] National Renewable Energy Laboratory (NREL), *NREL 2019 Annual Technology Baseline*. [3] ISO-NE, *ISO-NE 2016 Economic Study: NEPOOL Scenario Analysis*. [4] Massachusetts Department of Public Utilities, *Department of Public Utilities Approves Hydroelectricity Contracts*, 6/26/19, available at https://www.mass.gov/news/department-of-public-utilities-approves-hydroelectricity-contracts. [5] US Energy Information Administration (EIA), *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019*. [6] NREL, *The Vineyard Wind Power Purchase Agreement: Insights for Estimating Costs of U.S. Offshore Wind Projects*, February 2019.

[24] As we note in Figure 5, we find that a range of carbon emission prices would be sufficient to support the financing of renewable resources in the future. We selected this trajectory to illustrate the impact of an increasing carbon price on electric energy prices.

Figure 6: Projected Annual ISO-NE Locational Marginal Prices (LMPs)



Notes:

[1] The LECR scenario assumes 12.5% (2025), 17.5% (2030), and 30% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating. The low electrification scenario also assumes 25% (2025), 35% (2030), and 60% (2035) of consumers driving light-duty vehicles switch to electric vehicles.

[2] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional EE (25% increase over assumed 2035 EE) and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

IV. Summary of Observations

It is obvious that establishing enhanced carbon pricing in electric energy markets is not an easy path to take from political and regulatory perspectives. Nor is coming to agreement on any other mechanism with the same objective in wholesale markets. For many years, New England wholesale electricity market stakeholders have pursued additional market-based designs to compensate low-carbon resources for the value that states implicitly place on this attribute, with no success. New England's wholesale markets as designed will not come close to providing the revenue certainty needed to support investment in the resources required to meet the states' aggregate GHG reduction objectives.

Yet achieving these objectives through state-mandated programs and procurements will almost certainly achieve the results imperfectly, and at costs well in excess of what would result through efficient carbon pricing. We estimate that reliance on competitive markets with efficient carbon pricing to achieve the states' aggregate objectives – in contrast with reliance on utility-administered resource procurements – could save consumers on the order of $100–300 million ($2020) over the 10-year period 2026–2035.[25] While it is difficult to estimate with certainty what the level of savings could be, the expectation of substantial savings is supported by a wealth of experience with the introduction of competition in wholesale markets and the use of market-based mechanisms for emission control.

For more than 20 years, New England has embraced a competitive power market framework to guide stakeholder investment decision making in the power sector and remove investment risk from electricity consumers. The region has relied on market-based mechanisms for control of sulfur dioxide, nitrogen oxide, and carbon dioxide emissions. After analyzing our modeling results and assessing the region's history with competition and emission control programs, we conclude that implementation of carbon pricing in the electric sector can be a vital tool supporting the states' achievement of decarbonization targets at the lowest possible cost, while preserving and enhancing the benefits of wholesale market competition for New England's electricity consumers.

It is critical that we not lose sight of the inefficiencies that can result if the power markets cannot provide opportunities for all resources to earn equitable returns of and on capital investment and recover ongoing fixed operational and maintenance costs, driving New England states (either individually or through ISO-NE) to contract individually with capacity resources. Analysis shows that the impending addition of several thousand megawatts of large-scale renewable resources in New England will put downward pressure on wholesale energy prices as the frequency of zero-price energy hours grows. This not only reduces revenues for existing resources needed to maintain reliability, but also undermines the longer-term financial prospects for the increased quantities of renewable resources entering the marketplace – resources that will eventually become existing resources. Moreover, as technology rapidly evolves, the risk of contracting with resources that quickly appear uneconomic grows, along with the risk of stranded investments.

In addition, electricity consumers benefit from more efficient power pricing. Shifting the energy demand for vehicles and heating from fossil fuel sources to electricity results in a significant change in consumers'

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[25] This estimate is developed conservatively, assuming that zero-emission resource out-of-market costs for yet-to-be contracted resources would be 1–3% lower over the 10-year period 2026–2035 if resources were developed in response to competitive wholesale power market prices, as opposed to reliance on 20-year contracts. See Susan F. Tierney and Paul J. Hibbard, *Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets*, *Technical Appendix*, October 3, 2019, pp. A-15–A-18, for additional methodology detail.

expenditures for electricity. The electricity bill will become a more significant focus for consumers, potentially increasing the possibility that more consumers will respond to electricity price signals and adopt new technologies to minimize electricity costs. In this context, including an explicit price on GHG emissions in the electricity market will better align consumer choices with the societal benefits of reducing GHG emissions.

Below we highlight several key observations related to the power system modeling analysis and the benefits of carbon pricing in the context of New England states' decarbonization efforts.

Immediate adoption of a carbon-pricing mechanism in New England can provide many benefits in managing – and minimizing the cost of – a difficult transition to a decarbonized economy. Putting a price on electric sector emissions of pollutants is not new; it has a long history of successfully guiding industry transitions to lower-emission outcomes at the lowest possible cost to consumers. It is widely accepted that implementation of market-based emission control programs has dramatically lowered the cost of meeting more stringent ambient air quality standards.[26]

Given the magnitude and pace of GHG emission reductions required in the coming decades, a transparent price on carbon emissions can help smooth what may otherwise be a difficult transition. In a seamless way, with government direction, but without government intervention, carbon pricing can efficiently move operational decisions and resource dispatch away from emitting resources, and help direct new electric-sector investment dollars towards low-carbon sources of power. It will increase the value of reducing consumption, and can support levels of investment sufficient to fund both generating sources and the infrastructure needed to get distant resources to market. Carbon pricing has the potential to, in effect, "grease the skids" and reduce administrative and regulatory friction by the degree that is needed for development of sufficient low/zero-carbon resources to meet states' standards.

Introducing a carbon price in the electric sector allows for technology-neutral competition among both existing and new zero-emission resources, providing incentives to minimize costs and pursue innovation. The following benefits can be expected from introducing carbon pricing: (1) providing a durable market-based incentive that can bring forth and maintain zero-carbon resources to meet New England GHG reduction targets; (2) reducing reliance on out-of-market contracts that lock in long-term costs for consumers

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[26] See for example the SO_2 emissions reductions achieved as part of the cap and trade implemented as part of the 1990 Acid Rain Program: "The goal of Title IV of the Clean Air Act amendments of 1990, the Acid Rain Program, was to slash annual SO_2 emissions by 10 million tons from the 1980 baseline (26 million tons).… Between 1990 and 2004, SO_2 emissions from the power sector fell 36%, even as output from coal-fired power plants increased by 25% over the same period. The 8.95 million ton cap was reached in 2007. In 2010, by which time the cap and trade system had been augmented by the George W. Bush administration's Clean Air Interstate Rule, SO_2 emissions had fallen to 5.1 million tons." Justin Gerdes, "Cap and Trade Curbed Acid Rain: 7 Reasons Why It Can Do the Same For Climate Change," *Forbes*, February 13, 2012, available at https://www.forbes.com/sites/justingerdes/2012/02/13/cap-and-trade-curbed-acid-rain-7-reasons-why-it-can-do-the-same-for-climate-change/#4211a96d943a.

In addition to the observed emissions reduction success of the program, a retrospective review was conducted of the cost effectiveness of the program. The report discussed "how the costs of achieving environmental objectives through cap and trade compare with those of a 'counterfactual' (hypothetical alternative) command-and-control regulatory approach…. In addition to being less costly than traditional command-and-control policies would have been, the program's costs were significantly below estimates generated by government and industry analysts in the debate leading up to the passage of the CAA. In 1990, the U.S. Environmental Protection Agency (EPA) estimated the cost of implementing the Acid Rain Program (with allowance trading) at \$6.1 billion. In 1998, the Electric Power Research Institute (EPRI), an industry organization, and Resources for the Future (RFF), an independent think tank, estimated that total implementation costs would be \$1.7 and \$1.1 billion respectively (based in part on actual figures for the first few years of the program…). … In sum, the SO_2 allowance-trading system's actual costs, even if they exceeded the cost-effective ideal for a cap-and-trade system, were much lower than would have been incurred with a comparable traditional regulatory approach, and were much lower than the trading system's predicted costs. There is broad agreement that the SO_2 allowance-trading system provided a compelling demonstration of the cost advantages of a market-based approach." Gabriel Chan, Robert Stavins, Robert Stowe, and Richard Sweeney, *The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation, National Bureau of Economic Research Working Paper No. 17845*, February 2012, available at https://www.nber.org/papers/w17845.

and may prevent the rapid adoption of unforeseen technological advances; (3) increasing the opportunity for financing of clean energy resources in the absence of long-term contracts;[27] (4) increasing incentives for entrepreneurs and others to develop new supply-side and demand-side technologies, products, and services; (5) influencing consumer access to and use of demand-management technology and practices; and 6) seamlessly complementing other state policies by providing a means to value carbon investment in the electric system.

The commitment to a durable market attribute that appropriately incorporates the cost of carbon allows all resources to compete and ensures not only that zero-emission resources are compensated equitably, but that all other resources whose production is needed to ensure reliable system operations are compensated equitably. Existing zero-emission resources – whether nuclear, hydro-electric, or more recently added renewable resources with shorter asset lives – will be appropriately compensated for the zero-emission attributes of their resources. When evaluating investments, lenders can rely on a transparent wholesale energy price that values the social costs of carbon and provides a relatively stable future revenue stream. At the same time, the benefits that the addition of new zero-cost resources provides to consumers through lower market prices are still realized, while the recovery of the capital investments and ongoing operating costs need not be guaranteed by captive retail consumers.

The introduction of a carbon price in the power sector would increase wholesale electricity prices, but would not drive up consumers cost materially if states choose to rebate carbon revenues. Our analysis shows that as a carbon price is introduced, it will logically cause wholesale electricity prices to rise as fossil fuel generators add that cost to their energy market offers. That increased price, however, does not need to translate to materially higher consumer costs. Consumers can be compensated to offset the impact of energy price increases using the carbon revenues collected from fossil fuel generators. Recent studies have assessed a number of rebate mechanism designs that can equitably redistribute carbon revenues to consumers.[28] While the exact design and redistribution principles are beyond the scope of this report, New England states would be able to recover a significant amount of the revenue collected through a carbon price and return it to electricity consumers through financial mechanisms that retain the improved incentives of market prices incorporating a cost for CO_2 emissions. Moreover, the efficiency and value of electrification of transportation and residential heating could actually lower all-in energy consumption costs for consumers over time.

Analysis demonstrates that carbon pricing can establish a market-based, efficient mechanism to drive investment in resources needed in New England, and remove the need for separate state-mandated procurement of low-carbon resource investment. The absence of an effective carbon pricing mechanism is a fundamental challenge to continued reliance on competitive markets for efficient addition and attrition of power system resources. Markets (even including a RGGI price) currently fail to capture attributes essential to meeting the New England states' aggregate economy-wide GHG reduction goals. Absent adoption of a carbon price in energy markets, the pace and magnitude of additions of out-of-market, procurement-based resources will likely undermine the continued relevance of wholesale markets in New England as a vehicle for

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[27] Providing a durable carbon pricing mechanism will provide finance markets a basis upon which to evolve and create hedging instruments that can alleviate the need for state sponsored long-term contracts. See, for example, WindEurope, The value of Hedging: New Approaches to Managing wind energy resource risk, November 2017.

[28] See, for example, Marc A.C.Hafstead, Wesley Look, Amelia Keyes, Joshua Linn, Dallas Burtraw, and Roberton C. Williams III, *An Analysis of Decarbonization Methods in Vermont*, Resources for the Future, January 2019. See also Lawrence H. Goulder, Marc A. C. Hafstead, GyuRim Kim, and Xianling Long. *Impacts of a Carbon Tax across US Household Income Groups: What are the Equity-Efficiency Trade-Offs*? National Bureau of Economic Research Working Paper No. 25181, October 2018.

resource development and investment. The ideal pathway to decarbonization is one that *both* succeeds in meeting state GHG standards *and* does so at least cost through the operation of competitive wholesale electricity markets. Carbon pricing in energy markets is not an easy path to take, but it may be the only one that can preserve the operation of competition for the benefit of consumers.

Finally, we note the following additional observations based on the results of our modeling analysis that will be key considerations for the New England states' decarbonization efforts.

The New England States have set clear and progressive targets for economy-wide reductions in GHG emissions, targets that will require major changes in patterns of energy supply and demand over the next few decades. Over the past decade, the New England states have enacted wide-ranging laws and policies aimed at establishing progressively-declining levels of GHG emissions associated with states' economic activities, and complementary laws and policies promoting the development, commercialization, and uptake of low-carbon energy technologies. The states' commitments vary across the region, but the promulgation of climate-focused requirements has been steady and consistently driving towards greater and earlier reductions in GHG emissions.

Imagining end-state scenarios is interesting, but it is the pathway between now and then that will dramatically affect the degree of success and the cost to consumers; policymakers and industry stakeholders should focus carefully on the next 5–15 years. There is a fairly deep amount of literature on decarbonization of the US and/or states' economies that focus on what the end-state looks like – that is, what our supply and consumption of energy could be, consistent with the need to achieve reductions in GHG emissions on the order of 80 to 100 percent by 2050.[29] However, the usefulness of this information to inform policy and market design is low. Speculation decades out regarding technologies, costs, patterns of consumption, and consumer response to technology development and changing prices is likely to be highly inaccurate and is not particularly useful from either policy or technology investment perspectives. What happens over the near- to mid-term, though, is extremely important for setting an initial direction to the ultimate carbon reduction standards, and more importantly for identifying immediate market and policy mechanisms that can help put the region on an efficient and effective pathway consistent with reasonable progress towards the states' aggregate GHG emission reduction targets.

The electric sector will play an early and outsized role in achieving the states' GHG reduction standards. Requirements and policies of the New England states are increasingly focused on "leaving no stone unturned," and target significant reductions from all economic actors and all sectors of the economy. It remains highly uncertain how to achieve this level of GHG reduction across all economic sectors, and perhaps more importantly, how to do so in a least-cost manner. Yet analyses of GHG abatement cost curves generally arrive at similar conclusions:[30] the best, most immediate, and potentially least-cost pathway to decarbonization – at least based on current technologies and expectations – involves or will require

[29] For example, see the following: Commonwealth of Massachusetts, *Global Warming Solutions Act: 10-Year Progress Report*, April 2, 2019; Connecticut Governor's Council on Climate Change, *Building a Low Carbon Future for Connecticut: Achieving a 45% GHG Reduction by 2030, Recommendations from the Governor's Council on Climate Change*, December 18, 2018; State of Rhode Island and Providence Plantations, *Advancing a 100% Renewable Energy Future for Rhode Island by 2030, Executive Order 20-01,* January 17, 2020.

[30] For example, see the following: McKinsey & Company, *Impact of the financial crisis on carbon economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*, 2010; The New Climate Economy Project of the Global Commission on the Economy and Climate, *Technical Note: Quantifying the multiple benefits from low-carbon actions in a greenhouse gas abatement cost curve framework,* January 2015; Kenneth Gillingham, "Carbon Calculus," *Finance & Development*, December 2019; Oregon Department of Energy, *10-Year Action Plan Modeling: Greenhouse Gas Marginal Abatement Cost Curve Development and Macroeconomic Foundational Modeling for Oregon*, July 30, 2012.

widespread electrification of consumer transportation and residential heating sectors, concurrent with continuous reductions in the carbon intensity of electricity supply (that is, declining emissions of CO_2 per MWh of generation).

The transition to a decarbonized economy, and a decarbonized power system, will likely be difficult and costly. This report focuses primarily on electrification of transportation and residential heating alongside continuous decarbonization of the electric sector over the next 15 years, in quantities needed to achieve “reasonable progress” towards the ultimate end-state standards currently adopted by the New England states. Achieving this level of reasonable progress will be far from easy or cheap. As discussed in detail in this report, achieving the states’ standards will require an unprecedented level and pace of change in three fundamental respects: (1) the widespread adoption, at least among passenger vehicles, in electric vehicle technologies, alongside the rapid deployment of charging infrastructure to support the transformation of the transportation sector; (2) accelerated turnover in residential heating technologies from existing sources (such as oil, propane, wood, etc.) to heating systems based in part on efficient electric heating technology (heat pumps); and (3) a near-complete transformation of the bulk power system, including dramatic reductions in carbon-based generation, major investment in grid-connected and distribution low/zero-carbon generation sources, and fundamental changes in the level and pattern of electricity consumption.

Our review of pathways to decarbonization in New England with a focus on the next 10 to 15 years suggests several additional important takeaways for policymakers and stakeholders in the region to consider. Through our modeling of near/mid-term pathways and power sector outcomes, we have reviewed how electricity demand grows and changes in shape (daily and seasonally); how economic and policy drivers affect the addition and attrition of generating resources; how certain new resource needs likely require major transmission infrastructure investment; the overall pace of these fundamental changes to the bulk power system; and the potential for actively managing electricity demand to help reduce total compliance costs, provide an active reliability resource, and enable consumers to more directly respond to uncertain and changing electricity costs and rates. In consideration of these factors, we offer these additional observations beyond those related to carbon pricing in New England:

- *Don’t forget the low-hanging fruit* – It is fairly obvious that the coming decades will require market participants and consumers to have access to every tool in the toolbox so that the transition can proceed in a way that achieves the GHG reduction standards while minimizing costs and maintaining power system reliability. In this respect, proper market prices can send the right signals for consumer spending on energy efficiency and the greatest possible level of price-responsive demand, which can help achieve efficient outcomes.
- *Consider the impact on load growth and load shapes of new demand from electric heating and vehicle charging* – Consumer response to appropriate price signals can help manage EV charging and heating load, and can dramatically mitigate the power sector challenges that will arise with the impact of load growth on the level and shape of regional electricity demand. Our modeling demonstrates that, absent price signals reflecting system costs in how these loads are integrated, net demand outcomes could lead to costly and dramatically different system operational challenges than currently exist. Stakeholders should prioritize consideration of the impact of price incentives on how this additional load will affect daily load cycles and summer and winter peak load events.
- *Start now and continuously evolve retail rate structures to successfully address the previous two points* – Attention to the impact of electrification, demand response, and energy efficiency can contribute to active mitigation of the potential reliability and cost impacts of the transition. Rate design will be the principal determinant of whether load will evolve as a *contributor* or *impediment* to the

efficient and least-cost evolution of the power system. But because rates cannot and do not change quickly, proactive and planned evolution of utility retail rate structures – including the timely flow-through of wholesale price signals – must begin now, and continue actively throughout the transition.

- *Natural gas storage and delivery infrastructure will remain critically important over the next one to two decades* – Total annual consumption of fossil fuels for electricity, transportation, and heating will decline continuously over the transition, as will the total GHG emissions associated with these fuel sources. While this will eventually include the decline of total annual natural gas consumption for power generation, the overall magnitude of demand for natural gas on peak days to maintain power system reliability will change far more slowly, as remaining gas-fired resources are needed to reliably manage net-load variability in the transition to variable low/zero-carbon resources, and serve as critical back-up for days or events where demand peaks but renewable resource output is low.
- *Ensure that utilities rely on sound economic frameworks to evaluate utility infrastructure investment necessary to accommodate decarbonization* – The changes in consumer electricity usage patterns associated with electrification need to be carefully assessed so that future utility investments in infrastructure minimize costs to consumers. The collective impact of effective rate design and strategic investment in storage can be expected to support electric system infrastructure reinforcement. At the same time, aging infrastructure replacement can be designed to complement the changing pattern of system usage by consumers.