An Analysis of the Massachusetts 2018 'Act to Promote a Clean Energy Future'

June 21, 2018

Prepared for the Massachusetts Senate Committee on Global Warming and Climate Change

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Applied Economics Clinic and Sustainable Energy Advantage

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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Executive Summary

The Applied Economics Clinic, together with Sustainable Energy Advantage (the "AEC Team"), undertook this study of the impacts of the major electric sector provisions in the pending 'Act to Promote a Clean Energy Future' ("CE Future bill") at the request of the Senate Committee on Global Warming and Climate Change. The CE Future bill includes a substantial list of measures to reduce the Commonwealth's greenhouse gas emissions while capturing the benefits of new clean energy investments. Among the actions proposed in the CE Future bill are several changes to policies governing renewable electric generation, offshore wind development, and battery storage, along with changes to net metering rules that help to drive solar deployment.

Two decades of progressive clean energy laws have transformed the Commonwealth's electric sector, resulting in lower emissions, increasing the use of energy efficiency, and laying the groundwork for continued expansion of wind, solar and other renewable generating resources. Additional electric sector policies have the potential to bring jobs and economic development to the Commonwealth, while simultaneously playing a critical role in meeting greenhouse gas emissions reduction targets under the Global Warming Solutions Act (GWSA). It is also important to note that along with these policies, other sectors like transportation must make emission reductions in order to meet the Commonwealth's existing laws.

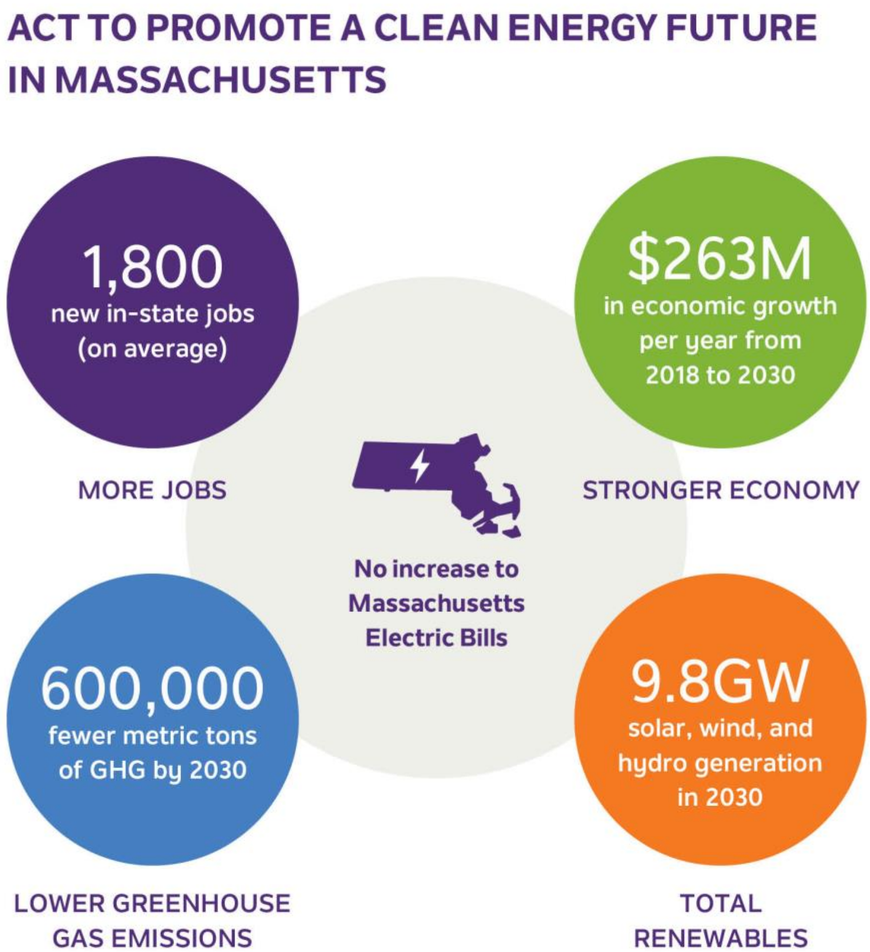
At the time of this analysis, the Massachusetts Senate Bill, an 'Act to Promote a Clean Energy Future,' includes four policies that focus on the electric sector:

1. **Renewable Portfolio Standard:** Accelerate the increase in the Massachusetts RPS from 1 to 3 percent per year, requiring utilities and competitive suppliers to increase the amount of renewable resources in the electricity they sell
2. **Offshore Wind:** Build 5,000 megawatts (MW) by 2035
3. **Battery Storage:** Reach an in-state battery storage goal of 1,766 MW by 2025
4. **Lift Net Metering Cap:** Remove the cap on "net metering" (selling energy back onto the grid) from small solar installations

AEC modeled the New England electric sector and Massachusetts economy to analyze the effects of these policies. Overall, we find that a more rapid increase in Massachusetts RPS requirements, expanding targets for offshore wind and battery storage, and less restrictive limits on net metering of distributed generation sources will have significant benefits for Massachusetts, including (see Figure 1):

- 1,800 new jobs on average
- $263 million in economic growth per year from 2018 to 2030—totaling $3.4 billion in growth over the 12-year period
- 9,800 MW of total solar, wind, and hydro generation
- A reduction of 600,000 metric tons greenhouse gas emissions for the Commonwealth
- No increase in Massachusetts electric rates and bills

Figure 1. Findings overview



These policies will bring new jobs and GDP growth to Massachusetts, and help the state make progress toward its climate goals. Emission reductions from the electric-sector policies are not enough on their own, however, to achieve the full 43-percent emission reduction called for in the Bill to comply with the Global Warming Solutions Act (GWSA). Additional emission reductions from transportation, buildings, and other sectors are needed in combination with electric-sector emission reductions to achieve this stronger target.

This report provides a description of methods, models, and assumptions used in analyzing the CE Future bill, as well as a summary of the results.

1. Background

The pending Massachusetts Senate bill, an 'Act to Promote a Clean Energy Future'[1] ("CE Future bill"), includes clean energy policies ranging from energy siting, to municipal waste standards, to electric vehicles (EVs). The bill lays out goals to "steadily transition the [C]ommonwealth to 100 percent clean, renewable energy by 2050,"[2] primarily by supporting clean energy development, energy efficiency, and energy storage while restricting fossil fuel development and reducing usage. It also includes provisions related to carbon pricing and other climate mitigation measures, which are not the subject of this report. In February 2018, Applied Economics Clinic (AEC) was engaged to study four provisions that focus on the electric sector, including accelerating renewable energy requirements, creating aggressive offshore wind and battery storage goals, and removing limits on rooftop solar. The study was funded by the Barr Foundation.

A total of 32 other bills related to clean energy issues have been introduced in the Massachusetts legislature since the beginning of the current (2017-2018) session—sixteen in the House by Representatives Golden, Haddad, Connolly, Benson, Mark, Khan, Decker, DuBois, Holmes, Smizik, Vincent, Kocot, Hecht and Baker, and 16 in the Senate by Senators Pacheco, Eldridge, Chang-Diaz, Gobi, Cyr, Lesser, Moore, Tarr and Barrett. The bills address many of the same issues as the CE Future bill including accelerating the RPS, advancing energy storage,[3] adjusting net metering caps for renewable facilities and low-income households,[4] and supporting renewable energy development.[5]

In this study, the Applied Economics Clinic (AEC), together with Sustainable Energy Advantage (SEA) (the "AEC Team") presents analysis of four areas of the Massachusetts electric-sector landscape that are addressed in the CE Future bill 1) the Massachusetts RPS; 2) offshore wind development; 3) energy storage; and 4) net metering of distributed generation sources. Table 1 below summarizes these provisions, comparing each policy change to current law.

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[1] At the time of the launch of this study, Senate Bill 2302.

[2] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Chapter 25D, Section 1, Line 529. https://malegislature.gov/Bills/190/S2302.

[3] See, e.g. H.1746: An Act to Advance Energy Storage, H.2600: An Act relative to promote energy storage systems, and S.1874: An Act relative to energy storage procurement for 2025 and 2030.

[4] See, e.g. S.1871: An Act relative to net metering and H.2712: An Act relative to net metering.

[5] See, e.g. H.3634: An Act Accelerating the Renewable Energy Portfolio Standard, H.2706: An Act relative to solar power and the green economy and H.1747: An Act to increase renewable energy.

Table 1. Electric sector proposals in an 'Act to Promote a Clean Energy Future'

Renewable Portfolio Standards

- Increases the RPS from an additional 1 percent to 3 percent of sales annually
- Establishes a statewide solar target of 20 percent by 2020 and 30 percent by 2030
- Encourages solar photovoltaic technology development
- Requires the equitable distribution of solar incentive programs to all Massachusetts communities

Offshore Wind

- Establishes a goal of 5,000 MW of offshore wind for Massachusetts by 2035
- Reduces the mandated wait time between procurements of offshore wind

Battery Storage

- Sets an energy storage goal of 1,766 MW by 2025 that must be reevaluated every 3 years
- Limits the quantity of energy storage that can be owned by load serving entities
- Allows alternative compliance payments for load serving entities that fail to hit storage targets
- Requires the state to set an energy storage target by 2020 for the year 2030

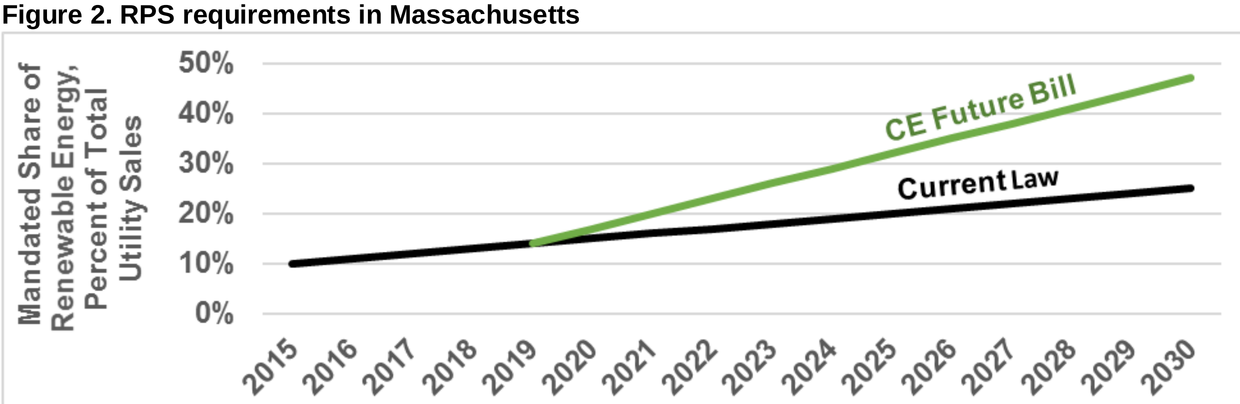
Net Metering

- Removes net metering caps from solar net metering facilities, aside from municipal or government facilities which are capped at 10 MW
- Allocates net metering credits to low-income and environmental justice residents
- Permits anaerobic digestion facilities to net meter and exempts them from net metering caps

Renewable Portfolio Standard

The current Massachusetts RPS requires investor-owned utilities and competitive suppliers to procure Class I Renewable Energy Certificates (RECs) equal to 15 percent of retail sales by 2020, and an additional 1 percentage point in each year thereafter. Under the CE Future bill, in 2019 the Massachusetts RPS would instead begin to increase by 3 percentage points each year (see Figure 2).[6]

Figure 2. RPS requirements in Massachusetts



[6] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Section 18, Lines 156-7. https://malegislature.gov/Bills/190/S2302.

Net Metering

Currently, Massachusetts electric customers generating 60 kilowatts (kW) or less of their own electricity from any generating technology may sell excess electricity back to the grid.[7] For solar, wind, or anaerobic digestion energy sources, private customers generating up to 2 MW, and public customers generating up to 10 MW, may net meter. There is currently an aggregate cap on net metering across all customers: 7 percent of the utility's highest historical peak load for private facilities, and 8 percent for public facilities.

The CE Future bill would remove net metering caps from anaerobic digestion and solar net metering facilities (except for municipal or government facilities, which each may only generate up to 10 MW).[8] The bill would also create new classes of solar net metering facilities, including "low income," "environmental justice," and "community shared" that may allocate their net metering credits directly back to their residents, as shown in Table 2 below.[9] For the purposes of the AEC Team's modeling, SEA provided the incremental solar projects that would be added due to the removal of the cap. Most of these new projects are commercial installations that are each larger than 25 MW.

Table 2. Net metering policies in Massachusetts

Net Metering Policies in Massachusetts	Current State	CE Future Bill
Net Metering Caps:		
Solar Facilities	Yes	No
Anaerobic Digestors	Yes	No
Net Metering Credit Allocation Permitted:		
Low-Income	No	Yes
Environmental Justice	No	Yes
Community Solar	No	Yes

Offshore Wind

Current Massachusetts law "allows for the procurement of up to 1,600 megawatts of offshore wind energy by 2027,"[10] but restricts the construction of renewable energy in offshore areas to be compliant with the protection and sustainability requirements of the Commonwealth's Ocean

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[7] Mass.gov. 2018. Net Metering Guide. https://www.mass.gov/guides/net-metering-guide.

[8] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Section 20, Lines 181-4. https://malegislature.gov/Bills/190/S2302.

[9] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Section 23, Lines 204-236. https://malegislature.gov/Bills/190/S2302.

[10] Mass.gov. 2018. Offshore Wind. https://www.mass.gov/service-details/offshore-wind.

Management Plan.[11]

The CE Future bill reduces the time currently required between offshore wind procurements from 24 months to 18 months,[12] establishes a goal of 5,000 MW of offshore wind capacity for the state by 2035,[13] and creates a Clean Energy Workforce Department Fund to increase jobs in renewable technologies, including wind.[14] See Figure 3 below for a snapshot of current offshore wind leases approved along the eastern coast of the continental United States.

Figure 3. Approved commercial leases for offshore wind development (2009-Present)

Source: Reproduced from the Bureau of Ocean Management's Renewable Energy Program's Fact Sheet. Available online at: https://www.boem.gov/BOEM-RE-Programs-Fact-Sheet/.

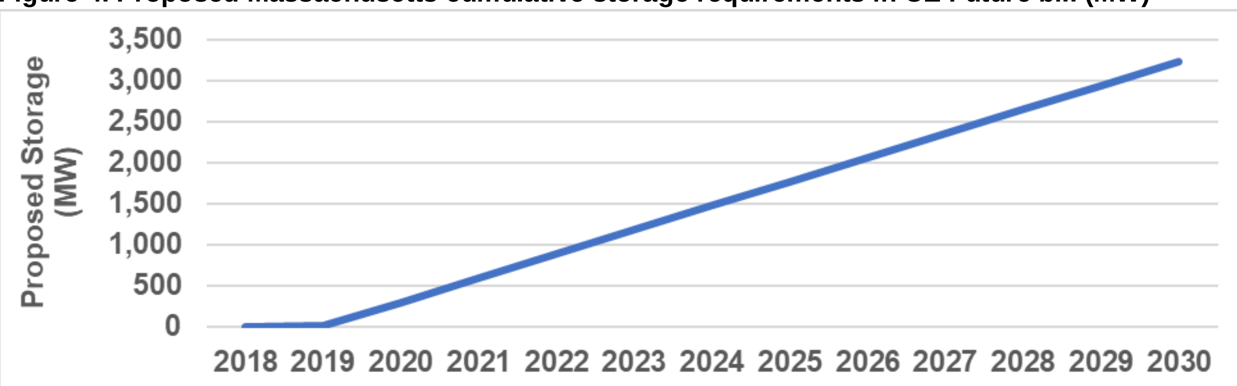
[11] Mass.gov. 2018. Massachusetts Ocean Management Plan. https://www.mass.gov/service-details/massachusetts-ocean-management-plan
[12] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Section 11, Line 72. https://malegislature.gov/Bills/190/S2302.
[13] Ibid, Section 11, Line 70.
[14] Ibid, Chapter 25D, Section 6(a), line 643.

Battery Storage

In 2015, Governor Baker's Administration set aside $10 million to explore and promote energy storage technology, develop the state's storage market, and recommend policy for the adoption of energy storage.[15] Following this initiative, a report published by the Massachusetts Clean Energy Center (MassCEC) and the Department of Energy Resources (DOER) found that 600 MW of storage would be possible in the Commonwealth by 2025.[16] Currently, Massachusetts law sets a goal of 200 megawatt hours (MWh) of storage available to electric utilities by 2020.[17]

An 'Act to Promote a Clean Energy Future' would: set an energy storage goal of 1,766 MW by 2025;[18] limit the amount of energy storage that can be owned by utilities;[19] require that the energy storage target be re-evaluated every three years;[20] allow DOER to create alternative compliance payments for utilities that fail to meet storage targets;[21] and require DOER to set new storage targets for 2030 and supporting policies by 2020.[22]

Figure 4. Proposed Massachusetts cumulative storage requirements in CE Future bill (MW)



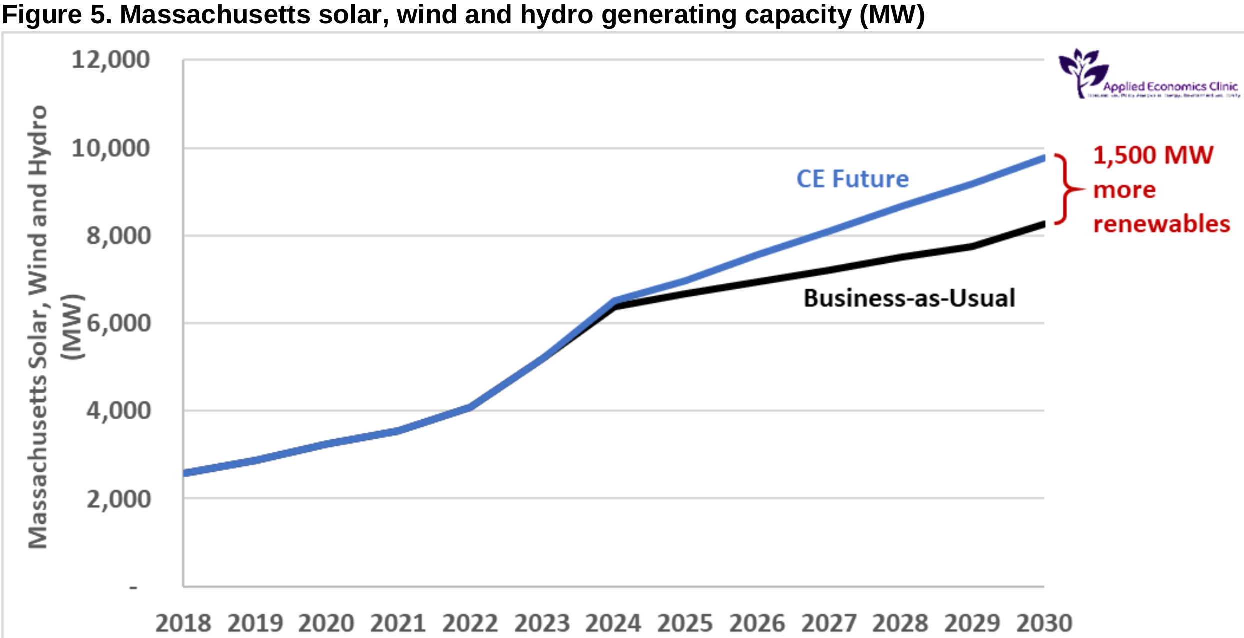
[15] Mass.gov. 2018. Baker-Polito Administration Announces $10 Million Energy Storage Initiative. https://www.mass.gov/news/baker-polito-administration-announces-10-million-energy-storage-initiative.
[16] Department of Energy Resources (DOER) and Massachusetts Clean Energy Center (CEC). 2016. State of Charge: Massachusetts Energy Storage Initiative Study. Pp.149. https://www.mass.gov/files/documents/2016/09/oy/state-of-charge-report.pdf.
[17] Mass.gov. 2018. Energy Storage Target. https://www.mass.gov/service-details/energy-storage-target.
[18] Ibid, Section 15(a), Lines 90-2.
[19] The General Court of the Commonwealth of Massachusetts. 2018. S.2302: An Act to Promote a Clean Energy Future. Section 15(c), Line 96. https://malegislature.gov/Bills/190/S2302.
[20] Ibid, Section 15(e), Lines 105-6.
[21] Ibid, Section 15(d), Line 100.
[22] Ibid, Section 15(b), Lines 93-4.

2. Findings

This section describes the results of modeling to determine the economic and greenhouse gas emissions impacts of four policies in the CE Future bill. One scenario modeled is a business-as-usual scenario to forecast what would occur without these policy changes. The "CE Future" scenario models the four major electric sector policy changes in the CE Future bill: increasing the Massachusetts RPS requirements, more offshore wind development, higher targets for battery storage, and fewer limitations on net metering, a key policy driving rooftop solar installation. We compare the outcomes of the CE Future to the business-as-usual scenario, and find that the bill results in an increase in jobs, higher economic growth, lower greenhouse gas emissions, and no increase to consumers' electric bills.

By 2030 under the CE Future scenario, Massachusetts is home to 1,500 MW additional (beyond business-as-usual) solar, wind and hydroelectric generating capacity (see Figure 5) along with another 3,200 MW of battery storage. To put this increase in renewable generation in context, 1,500 MW is more than twice the capacity of the Salem Harbor natural gas power plant that opened in 2018. The CE Future bill also includes measures that continue after 2030 that are not modeled in this study, including 1,700 MW more Massachusetts offshore wind generation to be built before 2035.

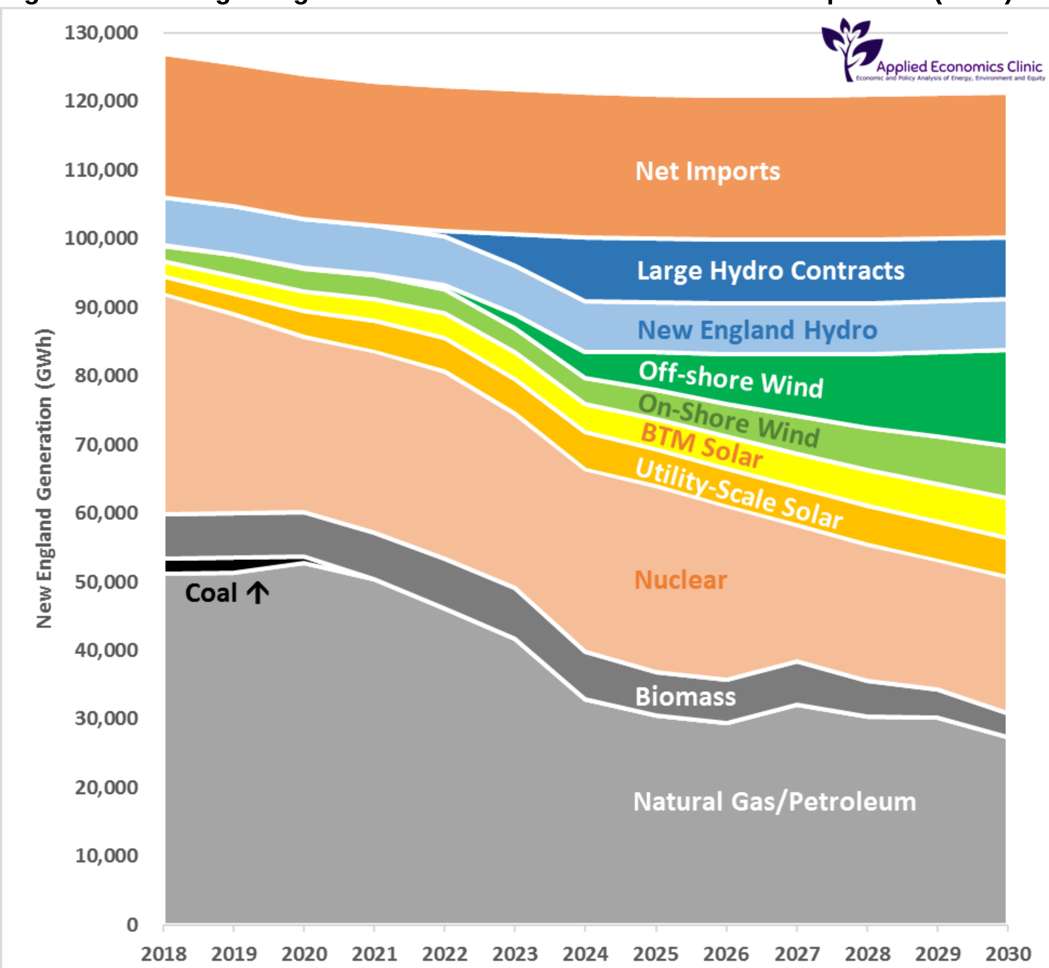
Figure 5. Massachusetts solar, wind and hydro generating capacity (MW)



For New England as a whole, Massachusetts CE Future policies add 5,000 MW to solar, wind, hydro, and battery capacity in 2030: 24 percent more zero-carbon generation and storage capacity than in a future without these policies. Battery storage also brings benefits related to electric system operations at times of greatest demand (usually the hottest afternoons in summer) that can be harder to observe in annual generation trends. This "peaking" resource lowers overall system costs, replaces some of the highest emitting natural gas, oil power plants with stored renewable generation, and eliminates the need for electric customers to pay for new gas generators that would be built to ensure that peak demand is met during a few times each year.

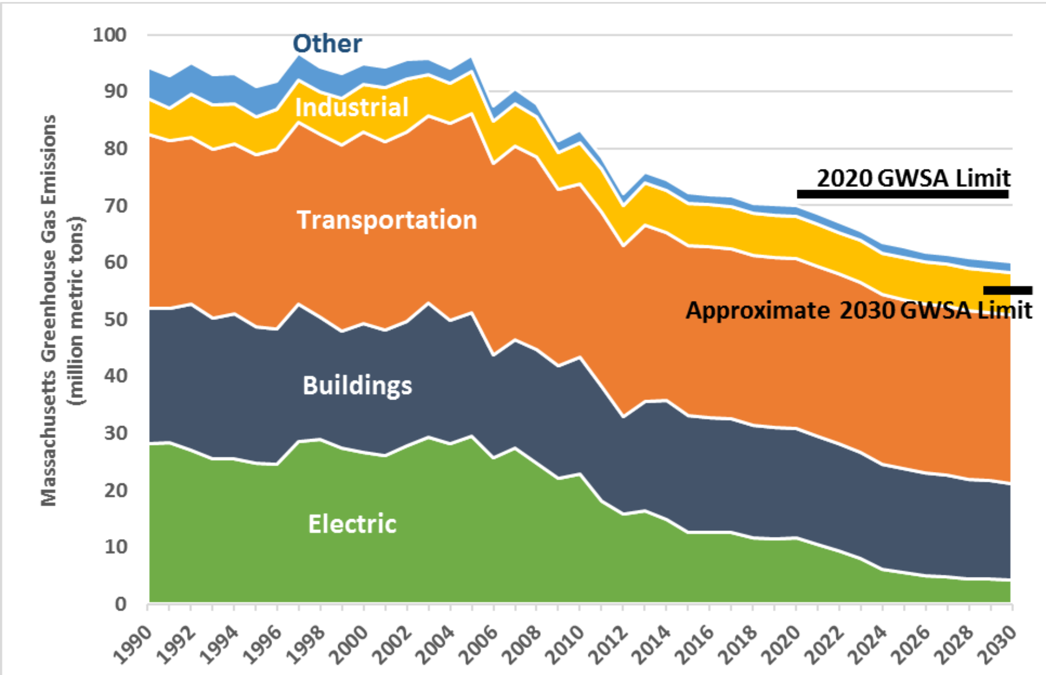
Figure 6 below shows the mix of generation supplying New England electric demand in the CE Future scenario. The additional investment in Massachusetts offshore wind, solar, and battery resources boosts the Commonwealth's economic activity while reducing its emissions of the greenhouse gases responsible for global climate change.

Figure 6. New England generation resources mix from CE Future policies (GWh)



Electric generation in the CE Future scenario results in a lower Massachusetts greenhouse gas inventory, as compared to the business-as-usual future. By 2030, Massachusetts emissions are 600,000 metric tons lower as a result of the 'Act to Promote a Clean Energy Future' electric sector policies. As shown in Figure 7, however, while these additions of renewables and battery storage are an important step towards compliance with GWSA emission limits, they are not by themselves sufficient to comply with the law. Additional measures in the buildings and transportation sectors will be needed to keep the Commonwealth on track to reach its 2050 target of an 80 percent reduction below 1990 greenhouse gas emission levels.

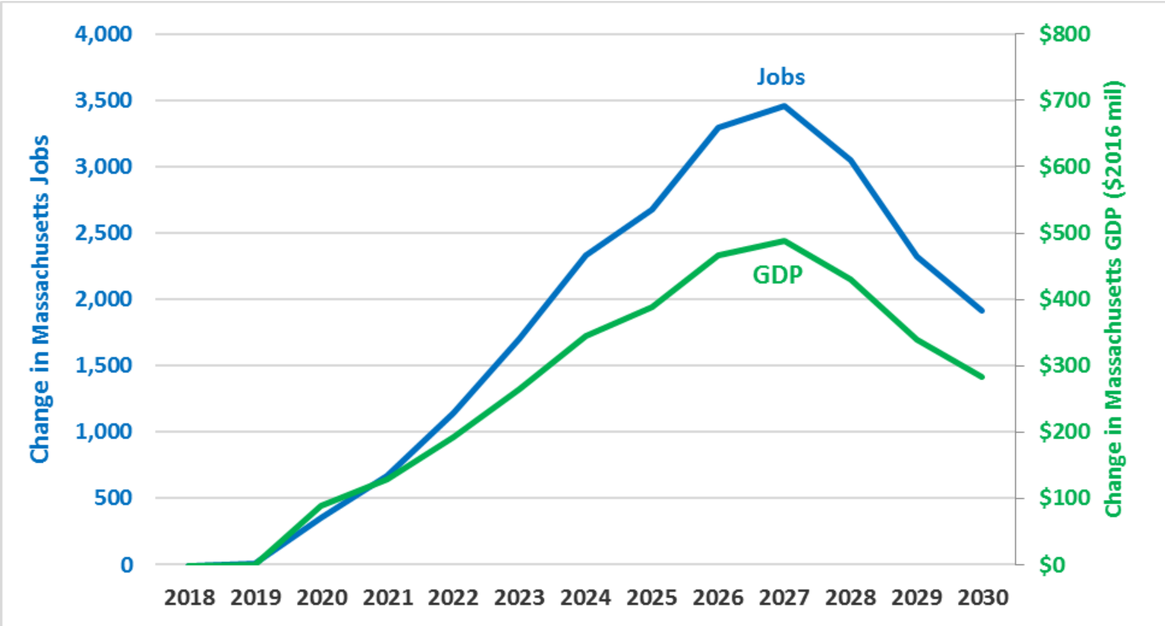
Figure 7. Massachusetts greenhouse gas inventory emissions from CE Future policies (million metric tons CO_2)



Investments in clean energy reduce Massachusetts' greenhouse gas emissions while also boosting the state economy. New wind turbines, solar panels and batteries mean jobs, business revenues and a higher tax base for the Commonwealth. Offshore wind turbines in particular bring several years of construction jobs in advance of these facilities' operations and maintenance. The analysis presented in this study includes only the economic benefits of energy infrastructure completed and brought into operation by 2030 within Massachusetts; it does not include the jobs and economic growth from infrastructure that would begin operation in 2031 and beyond, or any economic impacts outside of Massachusetts. For this reason, in this study job and GDP growth reach their highest point in 2027 and then begin to decline when new clean energy investment is curtailed in the model. (It is likely that actual jobs and GDP growth would be larger because they would include projects under construction in 2027 through 2030.) In 2027, economic growth from the CE Future bill reaches 3,500 Massachusetts jobs[23] and a $488 million increase to state GDP (see Figure 8).

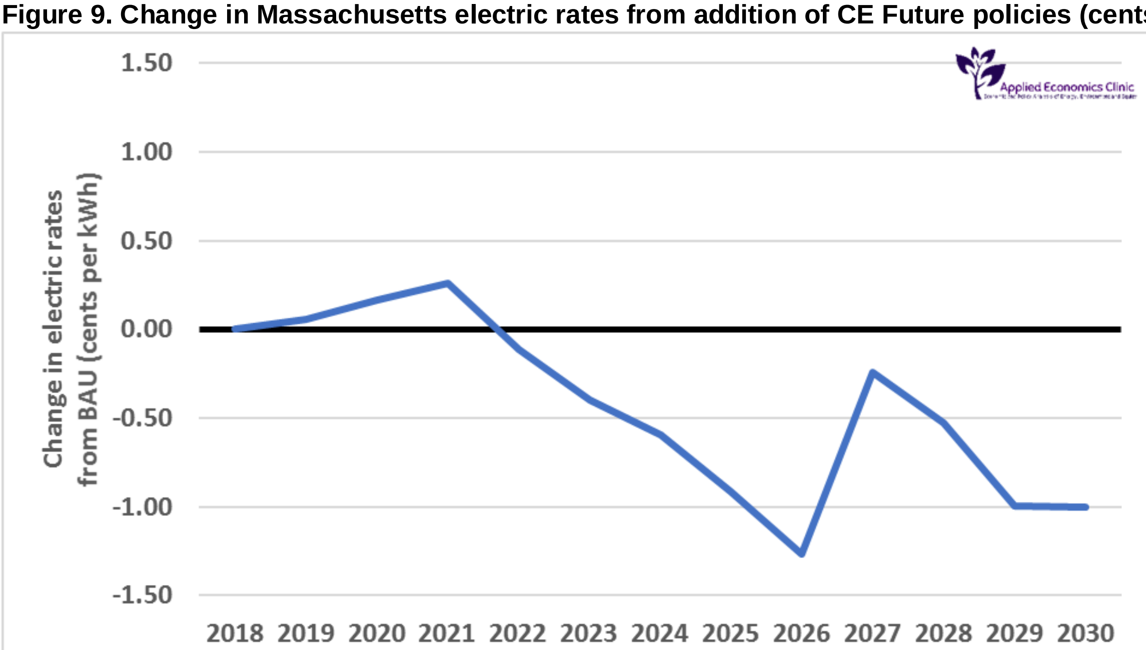
[23] Average change in direct, indirect, and induced from construction and O&M job years over the 2018 to 2030 period.

Figure 8. Change in Massachusetts jobs and GDP from addition of CE Future policies



After rising by one-quarter of one cent per kilowatt-hour over the next three years (an increase to the average household electric bill of 44 cents per month, and an increase of $30 per month for a 500,000 kilowatt-hour industrial electric bill), Massachusetts electric rates fall in the CE Future scenario (see Figure 9). On average, over the 2018 to 2030 period modeling, electric rates and customer bills were 1.5 percent lower in the CE Future scenario than they would have been without the CE Future bill's electric-sector policies.

Figure 9. Change in Massachusetts electric rates from addition of CE Future policies (cents per kWh)



Comparison to other studies

These results are largely similar in direction and scale to those published in May 2017 by Synapse Energy Economics in its analysis of a stand-alone acceleration of the Massachusetts RPS, commissioned by the Northeast Clean Energy Council and Mass Energy Consumers Alliance.[24] In addition to the specific inclusion of investment in off-shore wind generation and batteries, as well as reduced limitations on net metering, differences between this study and the May 2017 study are the result of several important changes in underlying assumptions, notably:

1. The New England grid operator (ISO-NE) has made significant changes to its forecasts of future energy demand, peak energy use, energy efficiency savings, and behind-the-meter generation for the region (see Figure 13). ISO-NE forecast of New England sales in 2027 has fallen from 124 terawatt-hours (TWh) to 115 TWh.

2. The U.S. Energy Information Administration (EIA) has released a new, substantially lower forecast of future natural gas prices (see Figure 19). EIA's price forecast of natural gas sold into New England in 2030 has risen from $4.26 per MMBtu to $6.95 per MMBtu.

3. The Synapse 2017 study modeled all six New England states. We are modeling Massachusetts only. Therefore, we do not capture jobs gained or lost outside of Massachusetts.

4. The Synapse 2017 study modeled scenarios that increased both Massachusetts and Connecticut RPS policies. We are only modeling an increase in the Massachusetts RPS—assuming no changes in other states' policies. Synapse did not model a 3 percent incremental RPS for Massachusetts alone. In the one scenario that Synapse modeled an increase in the Massachusetts RPS alone, it was a 2 percent incremental increase per year. In that scenario, the study found that there were zero job impacts.

5. Our "CE Future" scenario adds incremental solar, offshore wind or battery storage. The Synapse 2017 study did not add these three resources in its policy scenarios.

Taken together, these changes result in a shift in New England's generation needs, how they are met, and corresponding greenhouse gas emissions.

BVG's November 2017 *U.S. Job Creation in Offshore Wind: A Report for the Roadmap Project for Multi-State Cooperation on Offshore Wind* study was used to develop the spending pattern for our modeling of offshore wind.[25] That study showed significant job impacts from installing offshore

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[24] Synapse Energy Economics, Inc. May 15, 2017. An Analysis of the Massachusetts RPS. http://www.synapse-energy.com/about-us/blog/analysis-massachusetts-rps.

[25] BVG Associates Limited. U.S. Job Creation in Offshore Wind: A Report for the Roadmap Project for Multi-State

wind in the U.S.[26] However, we should note that the economic impacts from the BVG study differ from our impacts for several key reasons:

1. The BVG study measure impacts on the entire United States. Our study focuses only on Massachusetts. Our impacts count business activity within the Commonwealth, not in the rest of the United States.

2. The BVG study adds significantly more wind—4,000 MW or 8,000 MW, depending on their scenario—while we add 1,400 MW in our CE Future scenario based on the bill's requirements.

3. The BVG study has several scenarios of potential supply chains—again for the United States as a whole. We have not explored the potential for Massachusetts to provide more supplies for offshore wind farms. If the Commonwealth began producing more offshore wind supplies, then the economic impacts would increase.

Similarly, Massachusetts' Clean Energy Center's *2018 Massachusetts Offshore Wind Workforce Assessment* models an addition of 1.6 GW of offshore wind over an eight-year period and finds an average of 421 additional jobs in each year stimulated by this policy alone.[27]

Sensitivity findings

The AEC Team also tested the sensitivity of these modeling results to variation in demand for electricity and the price of natural gas.

High electrification sensitivity

In the high electrification sensitivity, Massachusetts electrifies an ambitious share of its cars and home heating systems, adding to electric demand but also reducing the use of fuels in the transportation and buildings sectors. The electrification of light-duty vehicles is consistent with the Eight-State Zero Emissions Vehicle Memorandum of Understanding (ZEV-MOU)[28]—adding over a million new electric vehicles in Massachusetts by 2030. In addition, heat pumps replace 19

Cooperation on Offshore Wind. November 2017. Figure 2. p.5. https://www.northeastwindcenter.org/wp-content/uploads/US-job-creation-in-offshore-wind.pdf

[26] When comparing economic impact studies, one must use caution between comparing "jobs" and "job-years." A job-year is the activity of one worker over the course of one year. This can be summed to create total job-years over a period of time or averaged to show the annual average "jobs." For instance, an impact of 100,000 job-years over a 20-year period is an annual average of 5,000 jobs.

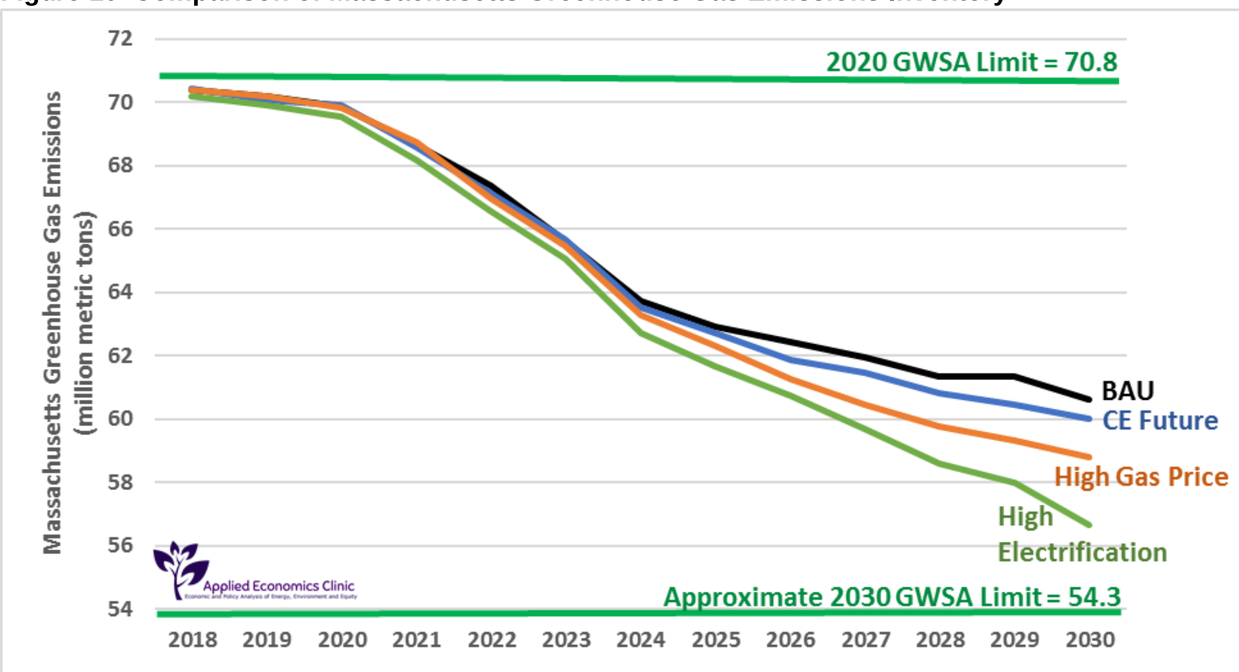
[27] Massachusetts Clean Energy Center. 2018 Massachusetts Offshore Wind Workforce Assessment. 2018. p.ix. http://files.masscec.com/2018%20MassCEC%20Workforce%20Study.pdf

[28] "State Zero-Emission Vehicle Programs: Memorandum of Understanding", October 24, 2013, www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf/

percent of space-heating in Massachusetts homes by 2030, consistent with the Northeast Energy Efficiency Partnership's (NEEP) "plausibly optimistic" scenario.[29] The result is 10 percent higher annual electric demand in New England in the high electrification sensitivity than in the CE Future scenario (and in the business-as-usual scenario and high natural gas price sensitivity).

Our modeling forecasts that higher demand for electricity prevents the 2027 retirement of Connecticut's Millstone 2 nuclear reactor, and prompts investment in an additional 300 MW of utility-scale solar farms in New England. Electric sector emissions change very little from the CE Future scenario but lower greenhouse gas emissions from the transportation and building sector bring the Massachusetts inventory to within 2.4 million metric tons of the 2030 target established in the CE Future bill (see Figure 10).

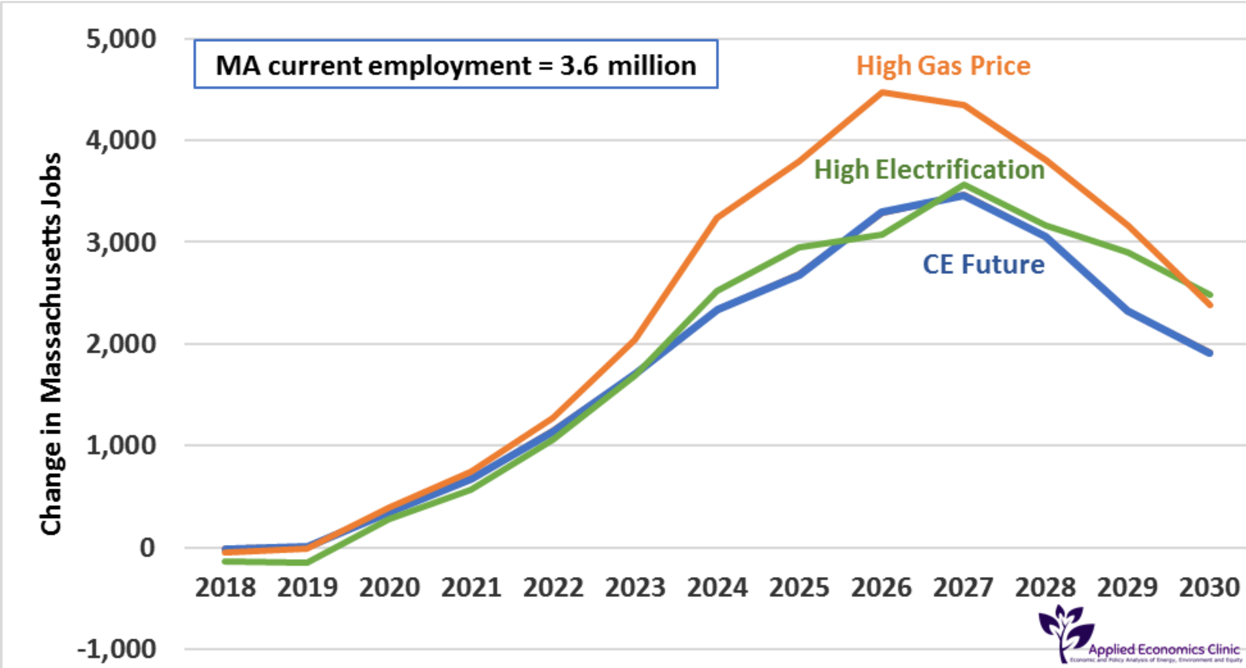
Figure 10. Comparison of Massachusetts Greenhouse Gas Emissions Inventory



Changes to customers' electric bills remain very small (on average across the modeling period, a 0.6 percent increase from business-as-usual). High electrification jobs and GDP are very similar to those found in the CE Future scenario: additional Massachusetts job-years from changes to electric-sector infrastructure and operations reach their maximum at 3,600 in 2027 (see Figure 11); and the total addition to state GDP over the twelve-year modeling period is $3.8 billion. New jobs from building electric vehicles infrastructure balances out jobs lost in fuel oil delivery.

[29] NEEP, July 2017, *Northeastern Regional Assessment of Strategic Electrification*, http://neep.org/sites/default/files/Strategic%20Electrification%20Regional%20Assessment.pdf

Figure 11. Comparison of Massachusetts change in employment



High natural gas price sensitivity

The high natural gas price sensitivity follows the high-end of the range of natural gas price forecasts presented by the U.S. Energy Information Administration in its 2018 Annual Energy Outlook. In response to higher natural gas prices, this sensitivity forecasts higher nuclear generation (again, forecasting that Millstone 2 would retire later than 2027) and additional investment in 1,800 MW of utility-scale solar farm capacity, replacing some generation from natural gas facilities. This results in somewhat lower emissions than in the CE Future (see Figure 10).

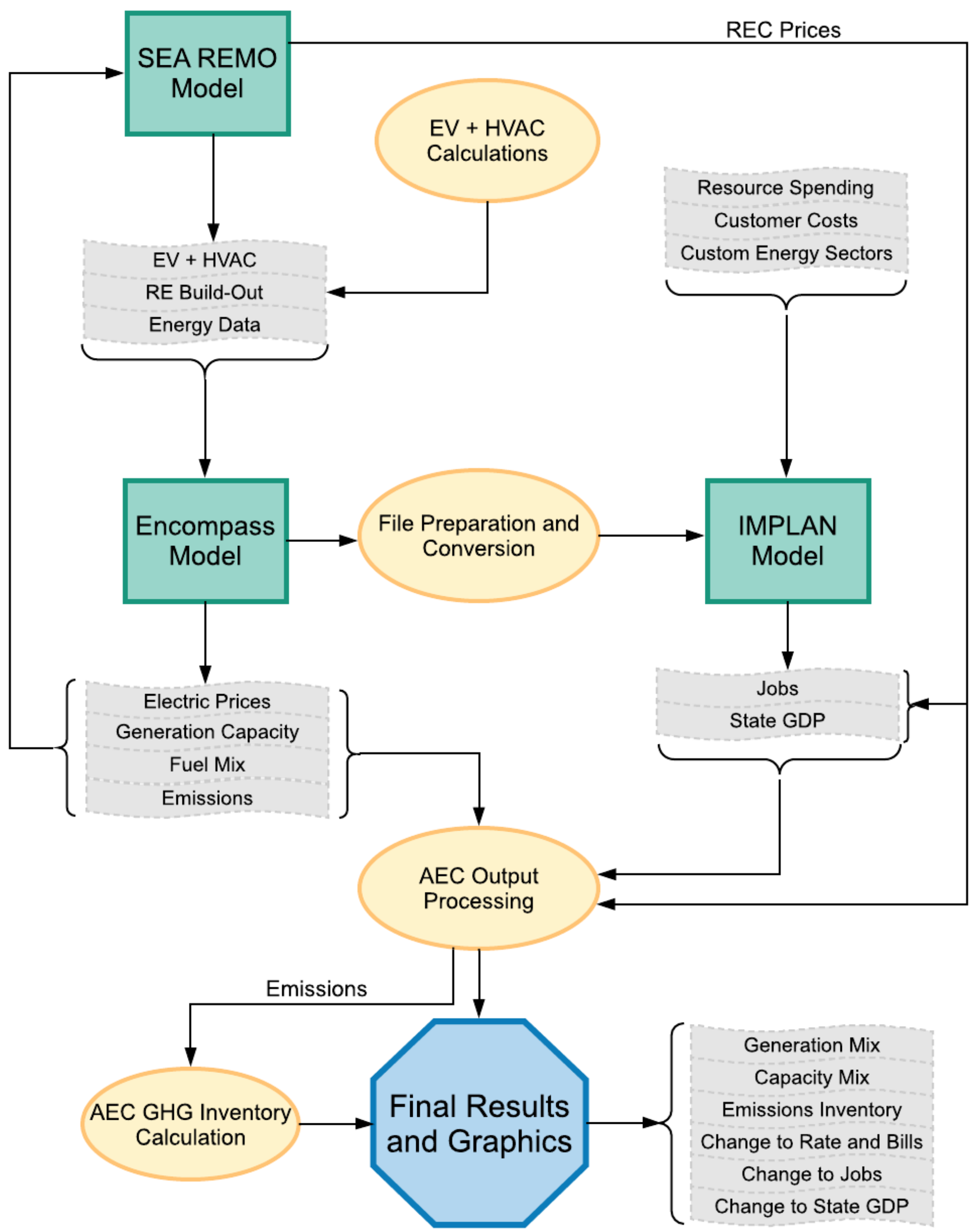
Again, changes to customers electric bills remain very small (on average across the modeling period, a 1.3 percent increase from business-as-usual). Additional solar infrastructure adds jobs and economic growth to the Commonwealth: additional Massachusetts job-years from changes to electric-sector infrastructure and operations reach their maximum at 4,500 in 2026 (see Figure 11); and the total addition to state GDP over the twelve-year modeling period is $4.2 billion.

3. Methodology

The AEC Team combined three models to produce these study results (see Figure 12):

- **Encompass:** electric sector capacity build-out and generation dispatch
- **REMO:** renewable energy build-out and REC prices
- **IMPLAN:** economic impacts including jobs and state GDP

Figure 12. Flowchart of study methodology



Encompass

Long-term capacity optimization and short-term dispatch analyses were performed using EnCompass, a power supply model developed by Anchor Power Solutions.[30] EnCompass assigns specific electric generating units to different geographical regions, along with projections for annual energy and peak demand. These regions are then linked with transmission resources to create an aggregated balancing area. EnCompass considers these existing units along with future capacity requirements to determine the optimal, lowest cost, future resource buildout subject to environmental constraints. This resource build is then dispatched economically to meet short-term energy requirements in the various geographic regions.

Regional output variables calculated by EnCompass include total generation, reserve margins, and energy and capacity prices. The model also provides a number of unit-specific output data on generation, unit starts, fuel and other variable production costs, ancillary services, and emissions. These data were provided by Horizons Energy Advisory Services.

The Renewable Energy Market Outlook Model

For this analysis, Sustainable Energy Advantage (SEA) deploys its suite of proprietary Renewable Energy Market Outlook (REMO) models. The REMO models forecast scenario-specific RPS Class I renewable energy build-outs and REC prices.

Near- and long-term dynamics are considered for both build-out and pricing. Near-term renewable builds are defined as projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. These projects are subject to customized, probabilistic adjustments to account for deployment timing and likelihood of achieving commercial operation.

Near-term REC prices are a function of existing, RPS-certified renewable energy supplies, near-term renewable builds, regional RPS demand (including Massachusetts Clean Energy Standard demand), Alternative Compliance Payments (ACPs) levels in each market, and other factors including banking, borrowing, imports, and discretional curtailment. Long-term REC prices are based on a supply curve analysis considering technical potential, resource cost, and market value of production over the study period. These factors are used to identify the marginal, REC price-setting, resource for each year in which new renewable energy builds are called upon. Long-term REC prices are estimated to be the marginal cost of entry for each year, meaning the premium requirement for the most expensive renewable generation unit deployed for a given year.

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[30] http://www.anchor-power.com/encompass-software.html

Economic Impacts

We use IMPLAN[31] to model the impacts on the Massachusetts economy from adopting policies included in an ‘Act to Promote a Clean Energy Future.’ The CE Future scenario results in new economic activity from the following:

- **Construction or installation of new resources:** Building a new energy resource requires hiring short-term workers and purchasing materials needed for the project. For instance, a new wind farm that is built (due to the policy) would generate a positive impact from the construction activity in the short-term. Conversely, if something would have been built in the business-as-usual scenario and is not built in the policy scenario, this would lead to negative economic impacts since the construction activity was foregone.
- **Operations of existing resources:** Energy resources require fuel, operations and maintenance in order to keep operating. These activities require long-term jobs, materials and services. For instance, a field technician that maintains wind turbines.
- **Electricity bill costs/savings:** Customers may see a change on their electric bill given what energy resources are built and operated. An increase (decrease) in the electric bill leads to less (more) spending available for other goods and services in the economy.

All economic impacts presented in this report are relative to the business-as-usual scenario. For this reason, the impact of the CE Future scenario can be interpreted as “what would happen under this policy over and above what would have happened without it.” The resource mix for each policy is determined by SEA’s REMO forecast of renewable resources and the electric system modeling in Encompass. The impact of building or operating resources outside of Massachusetts is only counted to the extent that this affects the Commonwealth’s residents and businesses’ electric bills. The economic impacts are reported in terms of employment and state GDP in the Commonwealth.[32]

IMPLAN is an industry-standard input-output model. IMPLAN provides key economic data for 536 industries in Massachusetts. It models the interactions between these industries based on flow of goods, services, and workers in and out of the Commonwealth as well as how each of the industries rely on one another. For instance, a new wind farm is built by a wind developer but relies on blade manufacturers for supplies (among many other industries). In some cases, we developed supplemental industries to accommodate the specificity of these activities that were not already captured in IMPLAN. The total economic impacts comprise the following:

- **Direct impacts:** These represent the jobs at the site of the investment. For instance, the workers installing solar panels on a solar farm count as “direct jobs.”
- **Indirect impacts:** These represent the jobs from providing supplies and services for the

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[31] http://www.implan.com/

[32] Employment or jobs in this report are in full-time equivalents (FTE’s).

investment. For instance, the workers producing wind blades that supply a wind farm are classified as "indirect jobs."

- **Induced impacts (from construction and O&M):** These represent the jobs associated with direct and indirect workers re-spending their wages in the local economy. For instance, jobs at restaurants patronized by wind farm technicians.
- **Induced impacts (from electric bills):** These impacts come from customers re-spending any savings on their electric bill (due to the policy).

Massachusetts Greenhouse Gas Inventory

We model the impact of an 'Act to Promote a Clean Energy Future' electric-sector policies on Massachusetts greenhouse gas emissions using the methodology inherent in Massachusetts Greenhouse Gas Inventory as follows:[33]

- **Electric sector:** For inventory purposes, Massachusetts electric-sector greenhouse gas emissions are calculated as using data from Encompass and REMO modeling:
    1. **Emissions from in-state generation**
       Massachusetts receives emissions associated with in-state generation, plus generation associated with RECs sold out-of-state, less generation associate with RECs and Clean Energy Credits (CECs) purchases from out-of-state and out of New England.
    2. **Emissions from New England (other than Massachusetts) generation:** Massachusetts is assumed to receive a share of the New England generation left over after each state meets its own needs. This share is calculated as Massachusetts residual need for generation over all New England states' residual need for generation.
    3. **Emissions from New York and Canada generation:** If needed, Massachusetts receives the same share of residuals of the emissions associated with non-REC/non-CEC generation imported from New York and Canada. We assume that this imported non-REC/non-CEC generation has an emissions rate equal to that of natural gas in the relevant region.[34]
- **Buildings sector:** Buildings sector (residential and commercial) emissions are assumed to be equal to their last recorded (2015) levels, reduced by:
    - **All scenarios and sensitivities other than the High Electrification sensitivity:** We assumed annual emissions reductions for the Buildings sector equal to the annual incremental natural gas energy efficiency savings predicted in the Massachusetts program administrators' 2016-2018 Three-Year Plan: 1.24

[33] Massachusetts Department of Environmental Protection. July 2016. Statewide Greenhouse Gas (GHG) Emissions Baseline & Projection Update. https://www.mass.gov/lists/massdep-emissions-inventories.
[34] Horizons Fall 2017 national database.

percent.[35]

- **High Electrification:** We assumed annual emission reductions equal to Avoided Energy Supply Components (AESC) 2018's "Heat pump share of thermal heating", which begins at 4 percent in 2018 rising to 19 percent in 2030.[36] (Business-as-usual emission reductions in this sector are assumed to be subsumed under, and not additional to, this AESC 2018 forecast.)

- **Transportation sector:** Transportation sector emissions are assumed to be equal to their last recorded (2015) levels,[37] reduced by:
  - **All scenarios and sensitivities other than the High Electrification sensitivity:** We adjusted Independent System Operator New England's (ISO-NE) Capacity, Energy, Loads and Transmission (CELT) 2018 annual electric sales forecast to account for electric sales to support an additional 10,000 EVs per year in Massachusetts and similar increase in electric vehicle (EV) penetration throughout New England consistent with the 2018 to 2019 increase in EV sales projected in the AESC 2018.[38] (That is, all years modeled for these scenarios have the same new EV sales: the 2018 to 2019 increase.) The EVs purchased also result in new CAFE-standard[39] cars not purchased, and the fuel and emissions from those cars are displaced. We assumed that the Federal Highway Administration's Massachusetts 2015 average vehicle miles traveled (VMT) per vehicle[40] would increase in accordance with that agency's reference case VMT growth projections[41], and that the fuel efficiency would grow according to the Energy Information Administration's (EIA) Annual Energy Outlook 2018 forecast for the "New Light-Duty Vehicle CAFÉ Standard".[42] Displaced gasoline was assumed to be 10 percent ethanol (E10) fuel with an emissions rate of 18.9 pounds of CO_2 per gallon.[43]

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[35] Department of Public Utilities (DPU). October 30, 2015. 2016-2018 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan. D.P.U. 15-160 through 15-169, Exhibit 1. http://ma-eeac.org/wordpress/wp-content/uploads/Exhibit-1-Gas-and-Electric-PAs-Plan-2016-2018-with-App-except-App-U.pdf

[36] Synapse Energy Economics. March 30, 2018. Avoided Energy Supply Components in New England: 2018 Report. Figure 54, pp. 242. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf.

[37] Mass.gov. 2018. MassDEP Emissions Inventories. Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2014, with Partial 2015 & 2016 Data. https://www.mass.gov/lists/massdep-emissions-inventories.

[38] Synapse Energy Economics. March 30, 2018. Avoided Energy Supply Components in New England: 2018 Report. Figure 53, pp. 240. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf.

[39] National Highway Traffic Safety Administration (NHTSA). 2018. Corporate Average Fuel Economy. https://www.nhtsa.gov/laws-regulations/corporate-average-fuel-economy.

[40] U.S. Federal Highway Administration. 2015. Highway Statistics Series: State Statistical Abstracts Massachusetts. https://www.fhwa.dot.gov/policyinformation/statistics/abstracts/2015/massachusetts_2015.pdf.

[41] U.S. Federal Highway Administration. May 2017. Forecasts of Vehicle Miles Travelled. https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.cfm.

[42] U.S. Energy Information Administration. 2018. *Annual Energy Outlook 2018.* Transportation Sector Key Indicators and Delivered Energy Consumption: Reference Case. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=7-AEO2018&cases=ref2018&sourcekey=0.

[43] U.S. Energy Information Administration. May 19, 2017. *Frequently Asked Questions.*

- **High Electrification:** The High Electrification sensitivity used the same methodology, data and assumptions for EVs with one exception: EV penetration for New England states was assumed to follow the AESC 2018 projection year by year, from 10,000 new EVs per year added in 2018 in Massachusetts to 210,000 added in 2030. In addition, heat pumps were assumed to displace a fixed share of natural gas and oil heating every year. The level of fuel displaced from heat pumps in Massachusetts was calculated using: 1) the EIA's State Energy Data System (SEDS) which provides total residential fuel consumption for Massachusetts and 2) the Residential Energy Consumption Survey (RECS) which provides the share of each fuel used for space heating for New England households. The emissions rates for each of those fuels was then applied to the avoided fuel usage.
- **Other sectors:** All other sectors are assumed to remain constant at last recorded (2014) levels.[44]

https://www.eia.gov/tools/faqs/faq.php?id=307&t=11.

[44] Mass.gov. 2018. MassDEP Emissions Inventories. Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory: 1990-2014, with Partial 2015 & 2016 Data. https://www.mass.gov/lists/massdep-emissions-inventories.

4. Assumptions

This study modeled the following set of scenarios and sensitivities to examine the expected impacts of Massachusetts 2018 'Act to Promote a Clean Energy Future' (see Table 3).

Table 3. Modeling scenarios and sensitivities

Scenario	Electric Demand	Natural Gas Price	RPS	Offshore Wind	Battery Storage	Net Metering Cap
Baseline: Business-as-Usual	Baseline (CELT with adjustments for EE, PV, EV)	Baseline	+1% annually	BAU	BAU	BAU
Baseline: CEFuture	Baseline (CELT with adjustments for EE, PV, EV)	Baseline	+3% annually	5 GW by 2035	1.8 GW by 2025	Continue SMART; lift NM cap
High Electrification: RPS, OSW, Battery, and NM Cap	High (CELT with adjustments for EE, PV, +EV, +Heat Pumps)	Baseline	+3% annually	5 GW by 2035	1.8 GW by 2025	Continue SMART; lift NM cap
High Natural Gas Price: RPS, OSW, Battery, and NM Cap	Baseline (CELT with adjustments for EE, PV, EV)	High Natural Gas Price	+3% annually	5 GW by 2035	1.8 GW by 2025	Continue SMART; lift NM cap

Energy usage forecast

The forecast for energy usage was based on review of ISO New England's 2018 Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report)[45], and the 2018 Avoided Energy Supply Components (AESC) study for New England, developed by Synapse Energy Economics.[46] Our "base case" forecast, shown in Figure 14, includes implied energy efficiency from the draft 2018 AESC forecasts and assumes that new EVs grow by the same amount in each year as they do from 2018 to 2019 in that study. Thus, the base case includes energy efficiency and a low amount of EV's added in each year. As shown below, expectations for energy usage in New England have changed significantly in the past year.[47] This is largely due to ISO-NE assumption of more energy efficiency and behind-the-meter solar photo voltaic (PV) in the future, both of which decrease system demand. Note that our forecast is slightly higher than the recently released CELT 2018 because we add more electric vehicles.

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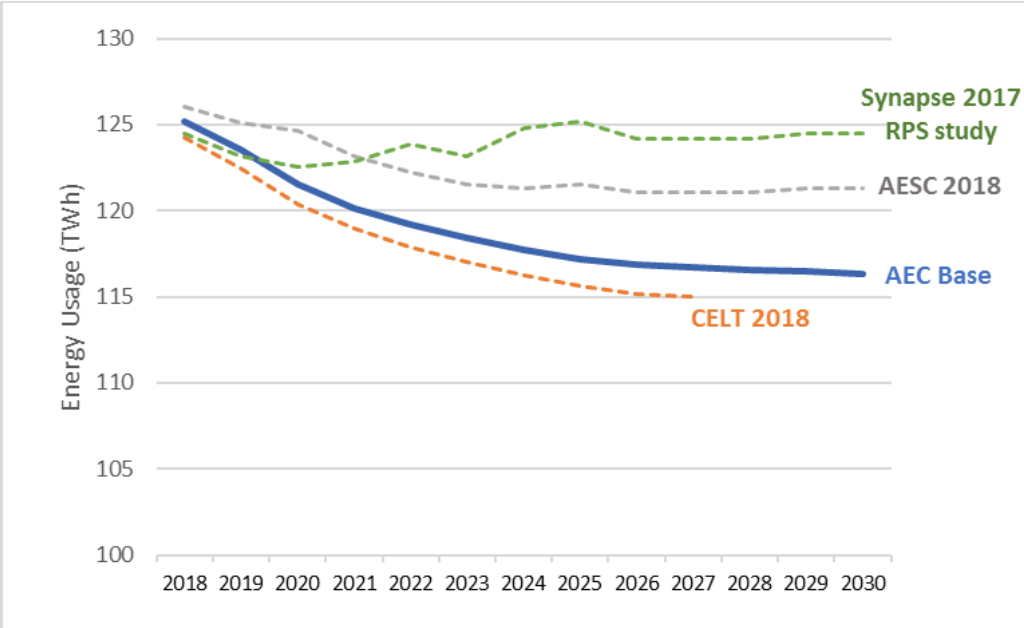
[45] ISO New England (ISO-NE). 2018. CELT Reports. https://www.iso-ne.com/system-planning/system-plans-studies/celt/

[46] Synapse Energy Economics. March 30, 2018. Avoided Energy Supply Components in New England: 2018 Report. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf.

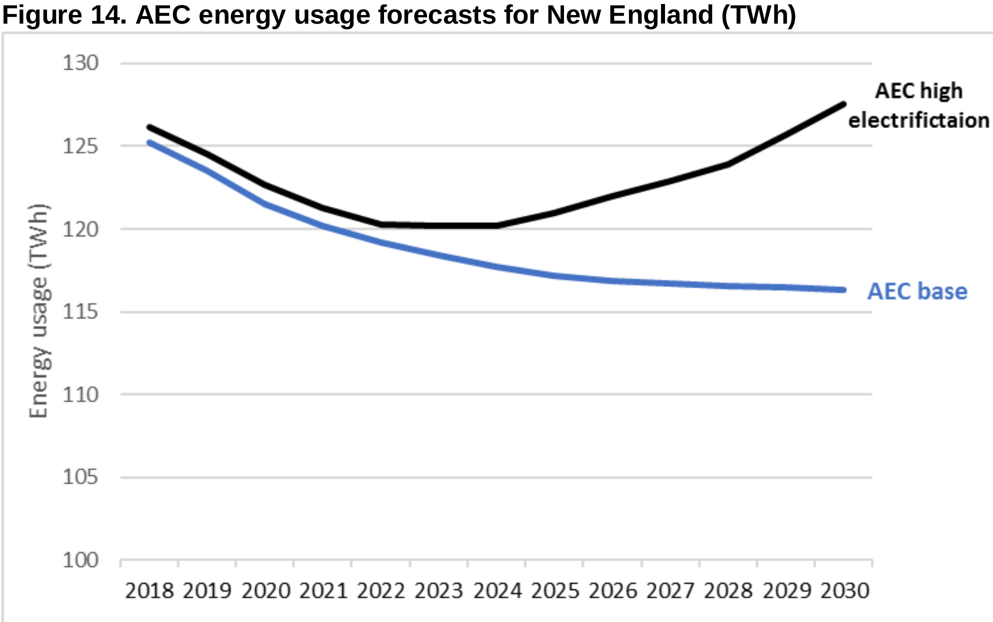
[47] Synapse Energy Economics and Sustainable Energy Advantage. May 2017. An Analysis of the Massachusetts Renewable Portfolio Standard. http://www.synapse-energy.com/sites/default/files/Analysis-MA-RPS-17-004.pdf

Figure 13: Energy usage forecasts for New England (TWh)[48]



The "high electrification" takes our base case and adds the implied energy for heat pumps and a higher projection of EV's as implied in the draft 2018 AESC's "high load" case. The state-specific 2017 CELT forecasts were used to apportion both forecasts into energy usage by state.

Figure 14. AEC energy usage forecasts for New England (TWh)



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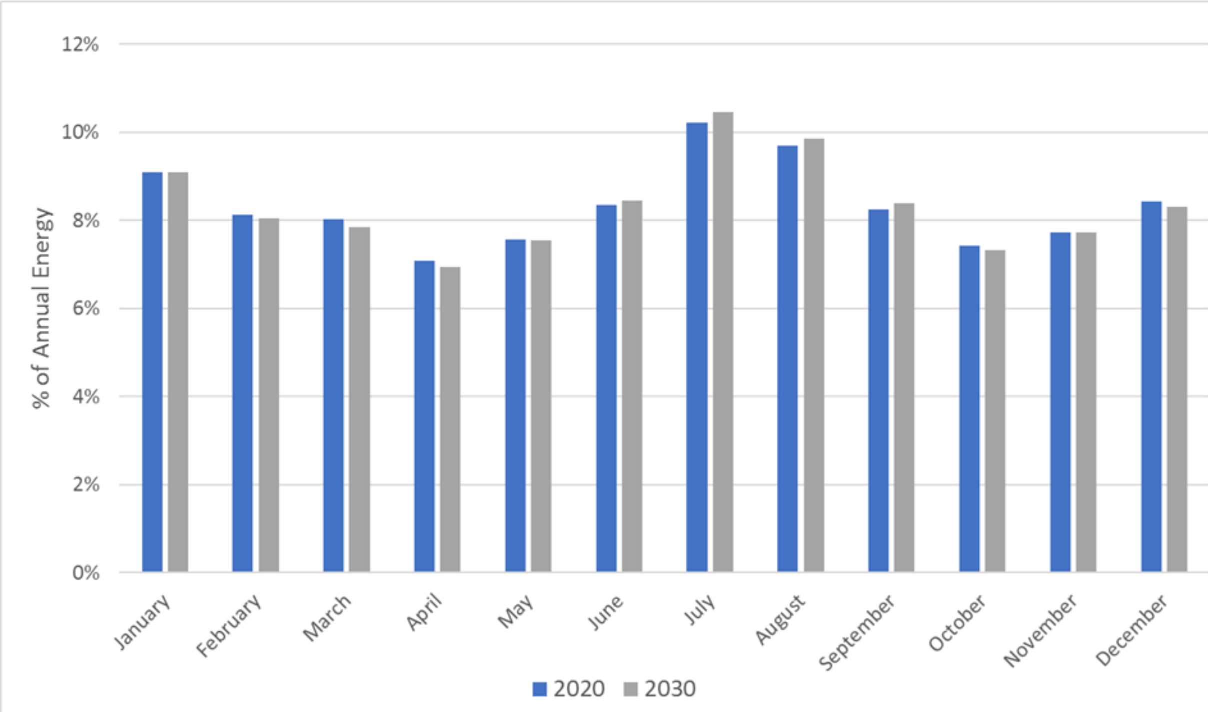
[48] CELT 2018 forecast is net energy (minus EE and BTM PV). AESC 2018 is the "2018 methodology" forecast. Synapse RPS 2017 is that report's "New England (with EE)" forecast.

The allocation of energy requirements by month was based on the breakdown in the CELT 2017 forecast data file.[49] This is shown below in Figure 15 for 2020 and 2030.

Figure 15. Monthly energy usage (% of annual energy usage)



Peak demand forecast

We translated the energy forecasts (shown above) into summer peak demand by relying on the implied "load factor" from the 2018 CELT forecasts of energy and summer peak demand.[50]

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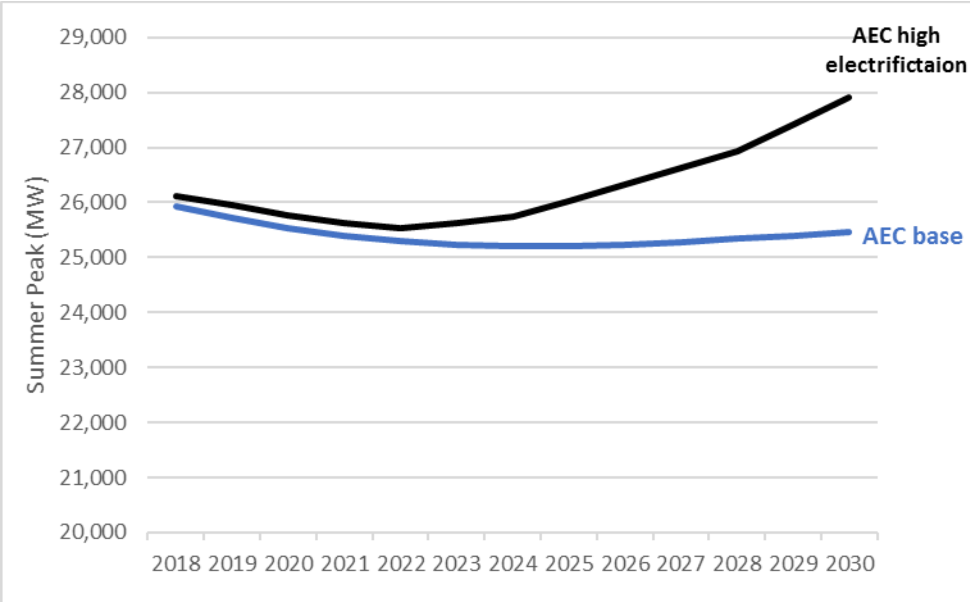
[49] 2017 CELT Forecast Data File. https://www.iso-ne.com/static-assets/documents/2017/05/forecast_data_2017.xlsx. This information was not available for the 2018 CELT forecast at the time our modeling was conducted.

[50] The load factor is calculated by dividing the energy usage by peak load multiplied by the number of hours in a year. [Load Factor = Energy Usage / (Peak Load x hours)].

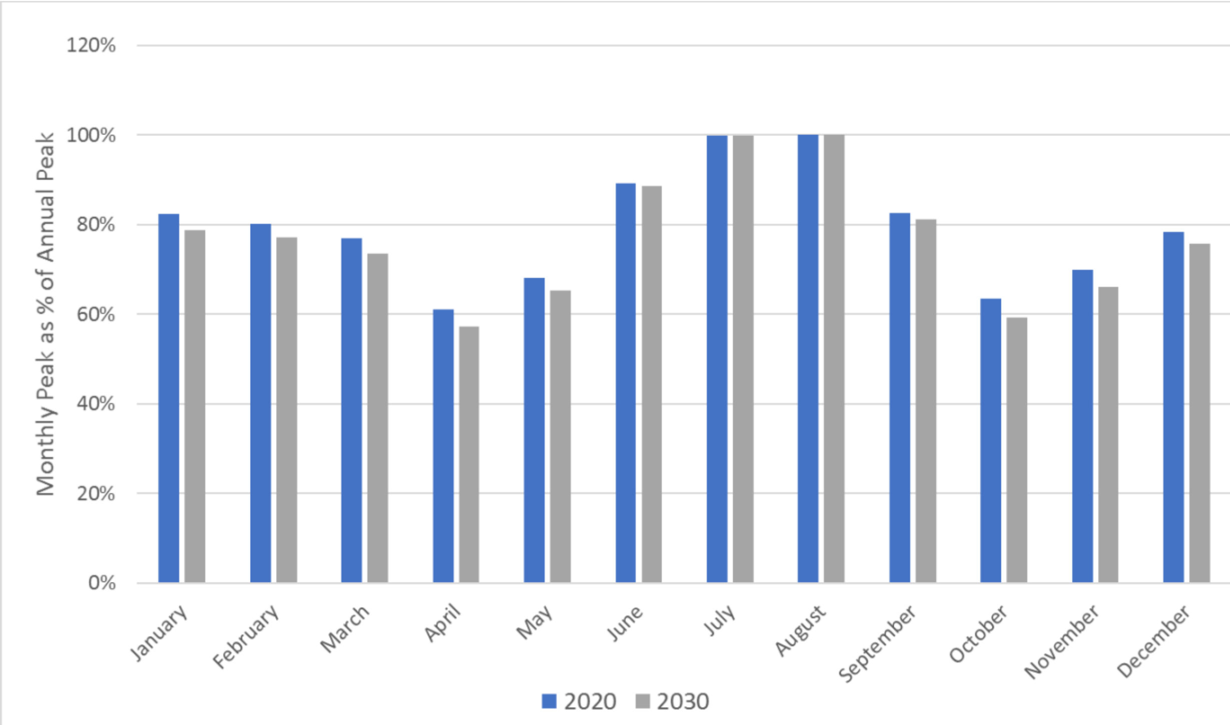
Figure 16. Summer peak load forecasts for New England (MW)



The peak demand for each month was based on the relationship between each month's peak demand and the annual peak demand (typically occurring in July). The percentages were taken from the 2017 CELT forecast data file, shown below in Figure 17 for 2020 and 2030.[51]

[51] 2017 CELT Forecast Data File. https://www.iso-ne.com/static-assets/documents/2017/05/forecast_data_2017.xlsx. This information was not available for the 2018 CELT forecast at the time our modeling was conducted.

Figure 17. Monthly peak demand (% of annual peak demand)



Renewable portfolio standards and other renewable policies

As a market fundamentals analysis, the supply, demand, and price dynamics modeled in REMO take all existing renewable energy policies into account. The expected participation of certified generators from adjacent control areas is also considered. REMO produces REC price outputs through 2030 for each Class I market in New England.

In each modeling run, the analysis assumes that all six New England states meet their renewable portfolio standard requirements, either through REC retirement or ACPs. We assume that there are no changes to the RPS policies in other states, and that Massachusetts makes no changes to the RPS policies applying to other classes.[52]

Table 4 shows the annual Class I or "New" RPS requirements applied in this analysis. In the CE Future scenario (and its respective sensitivities), we assume the change in targets takes effect in 2019, with 3 percent annual increases thereafter.

[52] After the conclusion of modeling for this report, Connecticut enacted a new law increasing its Class 1 RPS obligation from 20 percent by 2020 to 40 percent by 2030. All else equal, this will increase the demand for—and price of—the RECs used to satisfy both Massachusetts and Connecticut Class 1 RPS obligations. This impact is not included in this analysis.

Table 4. Current Class I or "new" RPS requirement in New England

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MA	12.0%	13.0%	14.0%	15.0%	16.0%	17.0%	18.0%	19.0%	20.0%	21.0%	22.0%	23.0%	24.0%	25.0%
CT	15.5%	17.0%	18.5%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
RI	9.5%	11.0%	12.5%	14.0%	15.5%	17.0%	18.5%	20.0%	21.5%	23.0%	24.5%	26.0%	27.5%	29.0%
VT*	1.0%	1.6%	2.2%	2.8%	3.4%	4.0%	4.6%	5.2%	5.8%	6.4%	7.0%	7.6%	8.2%	8.8%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH**	6.4%	7.2%	8.0%	8.8%	9.6%	10.4%	11.2%	12.1%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%

**Vermont RES Tier 2 (Distributed Generation)*

***After accounting for NH RPS Class I Thermal Carve-Out*

Summary of operating supply, near-term buildout, and resource potential

This analysis recognizes that Massachusetts's Class I RPS is implemented within the context of a broader marketplace of states and provinces, each with its own renewable mandate and target. These markets have overlapping eligibility criteria, so they compete on the margin to meet their respective demands. The REMO models take this eligibility dynamic into account. Table 5 shows the input assumptions for RPS supply modeled for this analysis.

Table 5. Input assumptions for RPS supply

	Input Assumptions	Scenario Notes
Operating Supply Assumptions		
Class I RPS, All Technologies	Based on RPS-certifications and SEA research	Operating supply does not vary by case, with the exception of biomass dispatch
Near-Term Supply Assumptions		
Utility Scale Onshore Wind & Solar	Units that have been RPS-certified, secured financing, or obtained long-term contracts	Near-term additions do not vary by case
DG, incl. BTM PV	MA: SREC-I & II; CT: LREC & ZREC; SHREC; Fuel Cells; RI: REGrowth; VNM VT: Standard Offer & NM	In "Net Metering Cap Removal" scenarios, assumed 56 MW of incremental solar to come-online in 2026 through 2030.
Other Technologies	Additional capacity where unique circumstances and policy supports allow	Estimated quantities will not vary by case.
Long-Term Supply Assumptions		
Onshore Wind	See additional contracting authority, below	Quantities deployed vary based on demand
Offshore Wind	MA: 1,600 MW between 2022 & 2030	In "5 GW by 2035," assumed to come on-line by 2035
	CT: 200 MW between 2022 & 2024 RI: 100 MW between 2022 & 2026	Estimated quantities will not vary by case.
Utility PV	Additional supply in response to incremental demand, and contracting authority	Quantities deployed vary based on demand case
Behind-the-meter PV	MA: 1,600 MW from SMART Program	Not varied by case.
	RI: REGrowth Expansion, CT: LREC/ZREC Expansion,	Not varied by case.
Other Technologies	Additional capacity where unique circumstances and policy supports allow	Estimated quantities will not vary by case.
Additional long-term contracting authority	MW: 9.45 TWh contracted by EOY 2022 (100% large hydro)	Estimated quantities will not vary by case.
	CT: 20 aMW of fuel cells RI: 80 MW	Estimated quantities will not vary by case.

Renewable and storage costs

The costs of renewable and storage are key inputs to this analysis. We reviewed many sources of cost forecasts in order to develop assumptions for New England. Capital cost assumptions for select years are provided below in Table 6. Further detail on the cost assumptions is discussed later in this section.

Table 6. Capital cost assumptions ($ per kW)

	2020	2025	2030
Utility-scale solar PV	$1,157	$1,035	$926
Commercial solar PV	$2,481	$2,026	$1,571
Onshore wind	$1,443	$1,393	$1,345
Offshore wind	$3,235	$2,887	$2,577
Battery	$977	$729	$544

Solar Photovoltaic

There are three types of solar photovoltaic (PV) systems in the market: residential, commercial and utility. Residential systems are typically between 3 and 10 KW in capacity; commercial scale installations are between 10kW and 2 MW, and utility-scale solar systems are those over 2 MW.[53] Capital costs for all systems include the panels, the power inverter,[54] panel site or roof preparation, permitting and interconnection costs, and labor for installation. Operations and maintenance (O&M) costs include insurance, taxes, maintenance fees, and the cost of new parts (such as replacement inverters).

Costs of solar installations have plummeted in recent years and are expected to continue to decline. We relied on Lazard's 2017 *Levelized Cost of Energy Analysis*[55] and the Horizons 2018 Spring database for utility-scale capital costs.[56] Lazard presents ranges of costs for each type of solar PV system. Horizons provides a cost estimates by region, as well as projected growth rates in capital costs. Given that the relative capital cost of solar in the Northeast region is higher than the national average, we used the high-end estimates for utility-scale solar from Lazard. This estimate was still lower than the Horizons base case capital cost. Based on our review of these data sources, we use the Lazard capital cost as a starting point for this study. Going forward, we applied the annual percentage growth rates for solar capital costs from the 2018 Horizons data.[57] Using this methodology, we estimate a capital cost of $1,289/kW in 2018, falling to $1,157/kW in 2020 and $926/kW by 2030.[58] O&M costs for utility-scale solar were assumed to be $11.75 per

[53] Ran Fu, David Feldman, Robert Margolis, Mike Woodhouse, and Kristen Ardani. August 2017. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. National Renewable Energy Laboratory (NREL). Pp. 28. https://www.nrel.gov/docs/fy17osti/68925.pdf.
[54] Solar PV output comes in the form of direct current (DC) which must be converted to alternating current (AC) through an inverter before the power can be supplied to the grid, home or business.
[55] Lazard. November 2017. Lazard's Levelized Cost of Energy Analysis – Version 11.0. Pp. 18. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.
[56] Horizons Spring 2018 national database (not publicly available).
[57] Lazard does not project future costs for solar, only current costs. Lazard costs were all adjusted to 2016 dollars using the Consumer Price Index (CPI).
[58] All estimates are in 2016 dollars unless other specified.

kW/year, based on Lazard.

We also relied on Lazard regarding the current costs of commercial solar installations; Horizons does not project costs for these resources. To model future cost changes, we relied on National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) which projects percentage annual growth in renewable resource costs.[59] The commercial solar estimate for 2018 is $2,729/kW, decreasing to $2,481/kW in 2020 and $1,571/kW by 2030.[60] Commercial solar costs are only applied to incremental installations for scenarios in which the net metering cap is lifted. O&M costs for commercial solar were assumed to be $19.58 per kW/year, based on Lazard. Residential solar installations are identical in all scenarios, that is; no incremental installations were projected and forecasts of residential solar costs were not used in this study.

Battery storage

Energy storage technology can collect excess energy that can be generated during cheaper, off-peak times and release it onto the grid to cover peak demand times. This comes in the form of flywheels, compressed air, pumped hydroelectric facilities and batteries (among others). There are numerous battery storage technologies currently available including lithium-ion battery, vanadium flow battery and zinc bromide flow battery. Of these, lithium ion batteries hold the lion's share of the market, accounting for nearly 99 percent of the national battery storage market in the last quarter of 2017.[61] Technological advancements have led to significant price decreases in storage systems, making them increasingly price competitive. According to IHS, the price for lithium-ion batteries decreased more than 50 percent between 2012 and 2015, and their estimate from 2016 predicted an additional price decrease of 50 percent before 2019.[62] GTM research forecasted the cost of energy storage components to decrease 40 percent between 2017 and 2022.[63] In part due to these price trends, the storage market grew 27 percent in 2017 alone, with total storage in the United States exceeding 1 gigawatt-hour (GWh) of electricity in that year.[64]

Our analysis focused on lithium-ion batteries—the prevailing battery technology in the short to medium-term. Lazard reported capital costs in 2017 for lithium-ion batteries (as peaking units)

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[59] National Renewable Energy Laboratory. 2017. Annual Technology Baseline (ATB) Data. https://atb.nrel.gov/electricity/data.html.

[60] *Id*. Mid" scenario percentage change from 2018 through 2030 for commercial solar.
Lazard. November 2017. Lazard's Levelized Cost of Energy Analysis – Version 11.0. Pp. 18. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

[61] Munsell, Mike. "US Energy Storage Market Tops the 1 GWh Milestone in 2017". Greentech Media. Match 6, 2018. https://www.greentechmedia.com/articles/read/us-energy-storage-market-tops-the-gwh-milestone-in-2017#gs.iMgf8SU

[62] *State of Charge: Massachusetts Energy Storage Initiative*. p.7. https://www.mass.gov/files/2017-07/state-of-charge-report.pdf

[63] Gupta, Mitalee. "U.S. Front-of-the-Meter Energy Storage System Prices 2018-2022". Greentech Media. February 2018. https://www.greentechmedia.com/research/report/us-front-of-the-meter-energy-storage-system-prices-2018-2022#gs.fXKEQqY

[64] Munsell, Mike. "US Energy Storage Market Tops the 1 GWh Milestone in 2017". Greentech Media. Match 6, 2018. https://www.greentechmedia.com/articles/read/us-energy-storage-market-tops-the-gwh-milestone-in-2017#gs.iMgf8SU

from $1,338 to $1,700/kW.[65] Capital costs were estimated to drop to $1,142 in 2018. Lazard's analysis estimated that the average capital cost of lithium-ion batteries across uses, including peaker replacement, would drop 36 percent between 2017 and 2021.[66] Future predictions from Horizons 2018 for the capital cost of storage in the ISO-NE region are expected to fall from $1,099/kW in 2018 to $977/kW by 2020 and then decrease significantly to $544/kW by 2030.[67] We used Horizons' estimates in our modeling, which showed similar percentage annual decreases in cost when compared to Lazard's in the early years. (Lazard did not provide medium to long-term projections.) Horizons also provided the operating costs of the lithium ion battery units used in our modeling which were $8.50 per kw-year in fixed O&M and $0.70 per MWh for variable O&M.

To encourage the installation of energy storage systems in Massachusetts, the Energy Storage Initiative (ESI) Program began in 2015 with an initial $10 million in funding for storage projects. In December 2017, an additional $20 million was awarded through the second phase of the program –Advancing Commonwealth Energy Storage (ACES)—to 26 storage demonstration projects across the state to showcase replicable storage use cases and models.[68] Projects include microgrids at universities and hospitals, bus charging stations, municipal light plant energy storage systems, commercial storage projects, and multiple combined solar plus storage systems. The largest project is a municipal light plant storage system based in Reading and will provide 10,000 kWh of electricity annually when complete. The 26 projects have a combined capacity of nearly 70,000 kWh, and 22 projects will use lithium-Ion batteries. Massachusetts lithium-Ion based projects are expected to produce nearly 60,000 kWh when complete at an average cost across projects of $1,335.65/kW, or $482.09/kWh.[69]

Offshore Wind

In December 2016, the 30-MW $360 million-dollar Block Island Wind Farm came into operation as the first offshore wind facility in the United States. Since then, the Bureau of Ocean Energy Management has auctioned offshore wind leases in Virginia, Maryland, Massachusetts, New Jersey, New York and North Carolina.[70] Offshore wind projects planned for the Atlantic Coast have benefitted from state policies to procure wind energy through Power Purchase Agreements (PPAs) or carve-outs in states' RPS specifically for offshore wind. Massachusetts requests for offshore wind projects of 400-800 MW are a two-to-fourfold increase in size over existing projects. Other

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[65] Lazard. November 2017. Lazard's Levelized Cost of Energy Analysis – Version 11.0. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.
[66] *Id*. p.16.
[67] Horizons Spring 2018 (not publicly available)
[68] Massachusetts Clean Energy Center. Advancing Commonwealth Energy Storage (ACES). http://www.masscec.com/advancing-commonwealth-energy-storage-aces.
[69] Advancing Commonwealth Energy Storage: Awardee Summary. AEC calculated average cost. http://files.masscec.com/Simplified%20Projects%20Summary.pdf
[70] Bureau of Ocean Management (BOEM). No Date. Lease and Grant Information. https://www.boem.gov/Lease-and-Grant-Information/.

projects include US Wind's 248-MW facility off the Maryland coast slated to begin operation in 2020 and Deepwater Wind's 120-MW Skipjack facility off the Delaware coast in 2022, energy from both of which will be sold over 20 years at $131.93/MWh.[71] Other projects off New York and Maine are estimated to cost $160/MWh and $230/MWh, respectively.[72]

Cost estimates for offshore wind projects consider key site parameters such as water depth and wind speed. Offshore wind facilities can be either fixed-bottom (attached to the ocean floor) or floating, with the latter being considerably more expensive. The capital costs include the cost of the wind turbines, the foundation, installation, electrical infrastructure and other costs associated with site development. In 2016, the National Renewable Energy Laboratory (NREL) estimated capital costs for fixed-bottom offshore wind projects from a baseline year of 2015 out to 2050.[73] NREL's cost estimates ranged from $3,891/kW for shallower, closer to shore projects to $5,442/kW for projects in deeper water and further from shore.[74] In the future, the cost was assumed to decline between 54 and 62 percent by 2050. Lazard estimates the current capital cost for offshore wind in the United States to be between $2,311 and $4,406/kW—or $3,358/kW on average.[75] O&M includes the annual fixed maintenance costs for offshore wind projects, including insurance, land lease payments, administration, replacement parts costs and maintenance. NREL averaged these costs to be $146/kW-year in 2015, and estimated these costs to gradually decline 7.5 percent in a mid-cost scenario and 16 percent in a low-cost scenario by 2050.[76] In comparison, Lazard's 2017 analysis estimates current O&M costs to be between $80 and $110/kW-year.[77]

New England offers some of the best offshore wind resources available in the United States. The ocean waters off New England provide high capacity factors of close to 50 percent—equivalent to European facilities.[78] Indeed, in a recent economic assessment of the potential of offshore wind, models predicted the greatest net value and economic potential among U.S. projects would be those located off the coasts of Maine, Massachusetts, Rhode Island, New Hampshire, New York and Connecticut—up to 9 GW.[79] The average wind speed in the northeastern Atlantic region is

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[71] U.S. DOE. 2016 Offshore Wind Technologies Market Report. p.29. https://www.energy.gov/sites/prod/files/2017/08/f35/2016%20Offshore%20Wind%20Technologies%20Market%20Report.pdf

[72] Ibid.

[73] National Renewable Energy Laboratory. 2017. Offshore Wind Power Plants. https://atb.nrel.gov/electricity/2017/index.html?t=ow#wiser-et-al-2016.

[74] Ibid.

[75] Lazard. November 2017. Lazard's Levelized Cost of Energy Analysis – Version 11.0. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

[76] Ibid.

[77] Ibid.

[78] Walter Musial, Philipp Beiter, Paul Schwabe, Tian Tian, Tyler Stehly and Paul Spitsen. 2016 Offshore Wind Technologies Market Report. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Pp. 67. https://www.energy.gov/sites/prod/files/2017/08/f35/2016%20Offshore%20Wind%20Technologies%20Market%20Report.pdf.

[79] Philipp Beiter, Walter Musial, Levi Kilcher, Michael Maness, and Aaron Smith. March 2017. An Assessment of the Economic Potential of Offshore Wind in the United States from 2015 to 2030. National Renewable Energy

between 9 and 10 meters per second (m/s), compared with other wind siting areas further south, that are between 7 and 8 m/s.[80] In Lazard's 2017 analysis, the capacity factor for U.S. offshore wind is between 40 percent and 50 percent.[81]

At this stage of their development, substantial uncertainty remains regarding the projected price of U.S. offshore wind projects, however, large reductions in capital costs are expected over the next thirty years. The AEC Team estimates the capital cost for offshore wind projects in 2017 to be $3,459/MW for fixed turbine installations. (We did not project floating turbine costs for purposes of this study.) To arrive at this number, we use Lazard's 2017 average of $3,358/kW, which was lower than Horizons' estimate in 2018, along with Horizons' Fall 2017 more modest annual percentage change (as compared to their trajectory developed for Spring 2018). Using this method, our capital cost estimates are essentially on-par with Horizons Spring 2018 by 2026.

Onshore wind

Because U.S. onshore wind is a more mature industry, there is less uncertainty and variation in cost forecasts. Costs are still expected to decrease, albeit at a slower pace than for solar PV or offshore wind. We relied on Horizons Spring 2018 forecast of $1,463/kW in 2018, decreasing to $1,345/kW by 2030. The 2018 price used here is very close to the average of Lazard's high and low range of onshore wind costs for the United States ($1,395/kW). We relied on Lazard for fixed O&M costs ($39/kw-year).

Heat Pumps

In the high electrification sensitivity, heat pumps displace the need for some oil and natural gas heating while increasing electric demand. The amount of space heating provided by heat pumps was based on the trajectory provided in the AESC 2018. By 2030, that study assumed that approximately 19 percent of residential thermal heating load in New England would be provided by heat pumps. We assumed that electric demand increased by the same increment shown in the AESC 2018.

Electric Vehicles

This study includes two possible trajectories of electric vehicle adoption in New England: a base case used in three of our four scenarios or sensitivities, and a high electrification case used in our

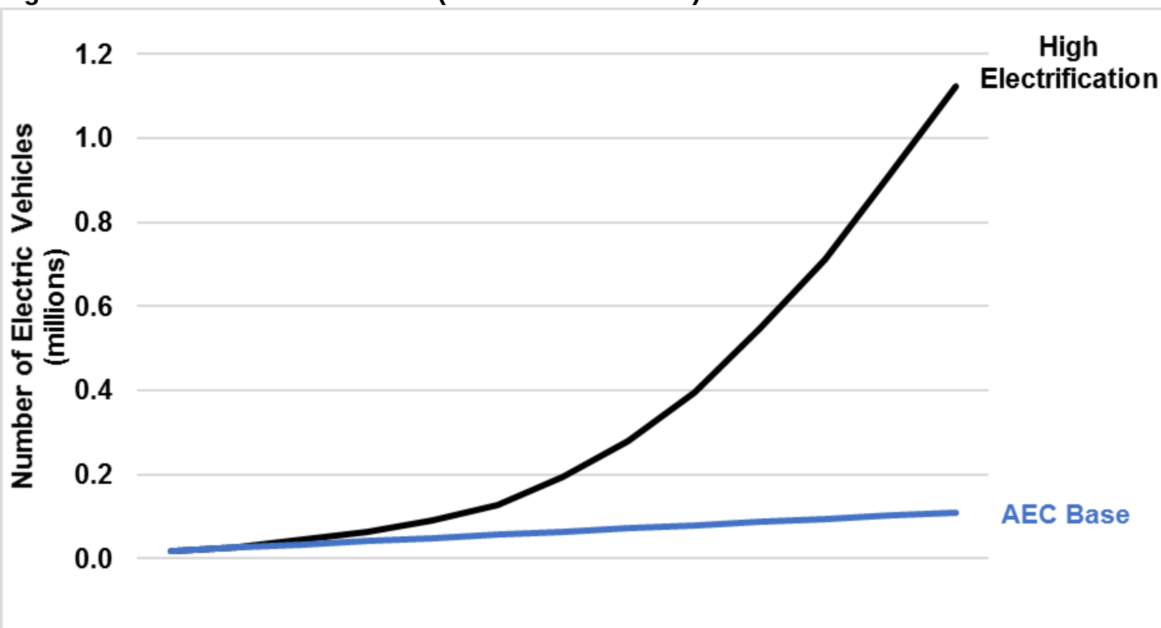
Laboratory. Pp 34. https://www.nrel.gov/docs/fy17osti/67675.pdf.

[80] Walter Musial, Philipp Beiter, Paul Schwabe, Tian Tian, Tyler Stehly and Paul Spitsen. 2016 Offshore Wind Technologies Market Report. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. p. 68. https://www.energy.gov/sites/prod/files/2017/08/f35/2016%20Offshore%20Wind%20Technologies%20Market%20Report.pdf.

[81] Lazard. November 2017. Lazard's Levelized Cost of Energy Analysis – Version 11.0. p.19. https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

"High Electrification' sensitivity. Both are based on projections from AESC 2018 and are included in our energy and peak load forecasts discussed previously.[82] In our base case, we assume the same number of EV's added in that study in the first year (2018 to 2019) are then added in each subsequent year. For Massachusetts, this leads to about 110,000 EV's on the road by 2030 in our base case (see Figure 18 below). For comparison, there are about 10,000 EV's currently in the Commonwealth.[83] In the high electrification case, we assume a more aggressive trajectory of EV adoption, based on the AESC 2018 "high load" case.[84] This case projects over 1 million EV's in Massachusetts by 2030.

Figure 18. Massachusetts EV fleet (millions of vehicles)



Natural gas prices

Natural gas generation is the marginal energy resource in New England in most hours, and therefore, often sets the wholesale electricity price for the region.[85] All generators are paid the wholesale electricity price. Thus, the price of natural gas is an important input for modeling the electric sector. Our forecast was based on Henry Hub natural gas prices from the EIA's 2018 Annual Energy Outlook (AEO) reference case forecasts and its Short-Term Energy Outlook

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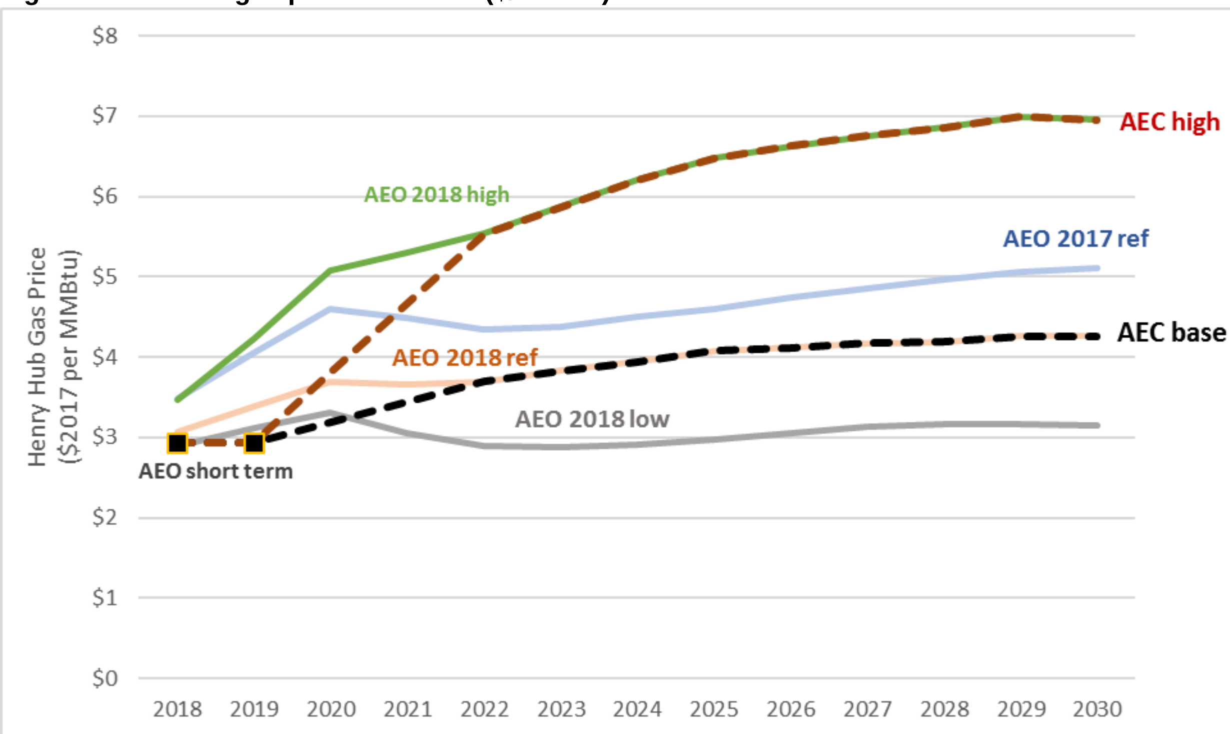
[82] Synapse Energy Economics. March 30, 2018. Avoided Energy Supply Components in New England: 2018 Report.
[83] Benson, Brian. "Electric Vehicle Ownership on the Rise in Massachusetts". MetroWest Daily News. September 13, 2017. http://www.govtech.com/fs/Electric-Vehicle-Ownership-on-the-Rise-in-Massachusetts.html
[84] Synapse Energy Economics. March 30, 2018. Avoided Energy Supply Components in New England: 2018 Report.
[85] ISO-NE. 2016 ISO New England Electric Generator Emissions Report. p.17. https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf

(STEO) forecast for 2018 and 2019.[86] The STEO is more up-to-date and in-line with natural gas market expectations (such as NYYMEX futures) for 2018 and 2019. Therefore, we decided to rely on the 2018 and 2019 prices from the STEO then the AEO 2018 reference case starting in 2022. In the interim years (2020 and 2021), our forecast prices increase linearly to meet the 2022 price from the 2018 AEO. These forecasts are shown below in Figure 19. For comparison, this figure also shows the 2017 AEO reference case and the 2018 AEO low gas price case. Our Henry Hub forecast is used in Encompass which then translates the forecast into New England-specific prices using a basis differential between New England and Henry Hub.

Figure 19: Natural gas price forecasts ($/MMbtu)



In the high natural gas price sensitivity, natural gas prices follow the same short-run forecast as in the AEC base case and then escalate rapidly to follow the AEO 2018 high natural gas price forecast (called "low oil/gas resource").

Behind-the-meter solar impacts on the grid

We accounted for reductions in energy and peak load that would be produced by incremental

[86] Energy Information Administration (EIA) Annual Energy Outlook. 2017 Reference Case with Clean Power Plan, 2018 Reference Case, and 2018 High Oil/Gas Resource and Technology case ("2018 low price"). https://www.eia.gov/outlooks/aeo/data/browser/
Short-Term Energy Outlook (STEO) from April 2018. Latest version is available here: https://www.eia.gov/outlooks/steo/report/

"behind-the-meter" solar PV resources. Unlike utility-scale solar PV, which acts as a supply-side resource, behind-the-meter solar is located at the site of the direct customer and decreases that customer's demand from the grid. We relied on the most recent forecast of behind-the-meter solar from ISO-New England. This behind-the-meter solar was accounted for in our energy and peak demand forecasts.

In the scenario and sensitivities where the solar net metering cap is lifted for Massachusetts, we accounted for reductions in energy and peak load that would be produced by incremental behind-the-meter solar PV resources. Therefore, for the relevant scenario and sensitivities the ISO-NE energy and peak load forecasts were reduced based on the incremental behind-the-meter solar (i.e. only those resources installed due to the lifting of the net metering cap) and an assumed percentage of peak load reduction for the amount installed. ISO-New England's annual PV forecast showed the amount of peak load reduction per MW of behind-the-meter solar installed in New England.[87] This calculation relies on the total amount of behind-the-meter solar on the New England system because, as more behind-the-meter solar is added, it reduces the impact on ISO-NE's peak as peak hours are shifted from mid-day to later in the day.[88] We extrapolated ISO-NE's trend to account for having more behind-the-meter solar on the system after 2027.

Economic impact assumptions

This study provides economic impacts (in terms of jobs and GDP) for the CE Future and its sensitivities relative to the business-as-usual. Therefore, each year's impact is incremental to a future without the policy being modeled. For this analysis, we conducted significant research to produce impacts customized to each energy resource. We also used the IMPLAN model which provides useful information on trade flow, commuter flows, and industry relationships. This data leads the model to produce unique multipliers (i.e. spin-off) impacts—including direct, indirect and induced impacts—for 536 sectors.

In some cases, the default IMPLAN sector was sufficient to model an activity for this study. For instance, the model has a sector for "construction of new power and communication structures" that is reasonable for modeling a new natural gas or biomass plant. In other cases, we modified IMPLAN's spending pattern for one of its default sectors. For instance, the IMPLAN sector "electric power generation - fossil fuel" was modified to develop a spending pattern for natural gas O&M. Finally, we developed our own spending patterns for other activities, including construction and O&M for offshore wind, onshore wind, small-scale solar PV, large-scale solar PV, and battery storage. These spending patterns were based on resource-specific research, including past economic impact studies. We had to determine both the proper sector to use in IMPLAN for each type of material and worker, and the percentage of total project costs that would be allocated to

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[87] ISO-NE. Final 2018 PV Forecast. https://www.iso-ne.com/static-assets/documents/2018/04/final-2018-pv-forecast.pdf
[88] ISO-NE 2017. p.60.

this sector. Further detail is provided below for each resource and activity.

General assumptions

The following assumptions broadly applied to our economic impact analysis:

- **Coal and nuclear generation.** There is no coal generation in Massachusetts and the its only remaining nuclear plant (Pilgrim) is slated to retire in 2019. There were no economic impacts from coal or nuclear generation because there were no changes in these activities between scenarios.
- **Timing of impacts.** The economic impacts are meant to reflect when each activity is taking place. Construction spending was assumed to be spread out evenly prior to when resource comes on-line. The time period for construction was resource-specific, mainly relying on EIA's assumptions used in its Annual Energy Outlook.[89] O&M impacts occur as long as each resource was operating.
- **Direct wages.** The wages for each resource activity were taken from state-specific data on industry wages from the U.S. Bureau of Labor Statistics (BLS).[90] This data was used for every resource, except for large-scale solar which used wage information from an economic impact study of a project in Vermont.
- **Labor compensation and wages.** The assumptions above pertain to wages only. The IMPLAN model works from "labor compensation" which includes wages, benefits, and taxes. IMPLAN offers data for each of the 536 industries to translate wages into labor compensation.
- **Full-time equivalents and employment.** IMPLAN presents "employment" as a headcount of number of workers in each industry; this method counts full and part-time workers equally. The job impacts presented in this report are in terms of "full-time equivalents" (FTE's)—that is 2,080 hours of work per year. We translated employment into FTE's using IMPLAN's sector-specific factors.
- **Inflation.** All GDP impacts are in terms of real 2016 dollars. Nominal dollars were translated into 2016 dollars assuming the 2.2 percent inflation rate used in the Horizons Fall 2017 database.

Offshore wind

Building offshore wind requires turbines, blades, towers, underwater cables, and foundations for

[89] EIA. Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018. Table 8.2. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

[90] U.S. BLS. Quarterly Census of Employment and Wages Private, NAICS 6-Digit Industries, Massachusetts 2016 Annual Averages, All Establishment Sizes. https://www.bls.gov/data/. NAICS industries used included "NAICS 237130 Power and communication system construction," "NAICS 221112 Fossil fuel electric power generation, "NAICS 238212 Nonresidential electrical contractors," "NAICS 221 Utilities," and "NAICS 541330 Engineering services."

each tower. The breakdown of these costs of installation, including labor costs, came from a BVG Associates study on offshore wind job creation, conducted for state energy agencies in Massachusetts, New York and Rhode Island, Massachusetts Clean Energy Center (Mass CEC) and the Clean Energy States Alliance.[91] Each of these materials was translated into the relevant NAICS (North American Industry Classification System) code and, following that, the relevant IMPLAN sector. NAICS codes for steel products used in wind farms came from an offshore wind study for Maryland.[92] NAICS codes for blades and towers came from a report of the supply chain of wind farms in Illinois.[93] IMPLAN sectors used for materials included "turbine and turbine generator set units manufacturing," "power, distribution, and specialty transformer manufacturing", and "other fabricated metal manufacturing." The installation labor used several IMPLAN sectors including "construction of new power and communication structures," "architectural, engineering, and related services," and "scenic and sightseeing transportation and support activities for transportation." The latter sector includes port and harbor operators that are required to transport supplies and workers to the site. A similar set of sectors are used for annual O&M spending.

Onshore wind

The construction of onshore wind relied, in part, on the research done for offshore wind where the components were similar. However, there were several key differences for onshore wind (relative to offshore wind): 1) a higher percentage of the project's costs were allocated to turbines; 2) activities related to water transportation were translated into truck transportation; and 3) the foundation for the tower included concrete. The most important factor was the change in costs of the turbine relative to the cost of the whole project. This information was gleaned from a BVG report for onshore wind.[94] The installation labor used similar IMPLAN sectors to offshore wind except that "truck transportation" was used instead of "scenic and sightseeing transportation and support activities for transportation." O&M for onshore wind used "construction of new power and communication structures" and "electric power transmission and distribution" IMPLAN sectors. Lease payments to landowners were $8,100 per MW per year, based on an NREL study. These payments passed through to Massachusetts residents—reducing overall energy customer costs (discussed later in further detail).

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[91] BVG Associates Limited. U.S. Job Creation in Offshore Wind: A Report for the Roadmap Project for Multi-State Cooperation on Offshore Wind. November 2017. Figure 2. p.5. https://www.northeastwindcenter.org/wp-content/uploads/US-job-creation-in-offshore-wind.pdf

[92] Pedro Guillen, Nic Wetzler, and Nick Abstoss. Analysis of Maryland Steel Facilities for Sufficiency to Support Offshore Wind Energy Deployment. Prepared for State of Maryland, Maryland Energy Administration. p. 92-94. http://energy.maryland.gov/Documents/AnalysisMarylandSteelFacilitiesSufficiency_SupportOffshoreWindEnergyDeployment.pdf

[93] Dr. David Loomis, Dr. J. Lon Carlson, and Dr. James Payne. Illinois Wind Turbine Supply Chain Report. June 2010. p. 9.

[94] BVG Associates. Economic benefits from onshore wind farms. For ScottishPower Renewables. September 2017. p.11. https://bvgassociates.com/wp-content/uploads/2017/09/BVGA-18510-Economic-impact-onshore-wind-report-r3.pdf

Large-scale solar

Large-scale ("utility-scale") spending was in part based on an economic impact study performed for the Coolidge solar project in Vermont.[95] Some of the IMPLAN sectors were specified in that study, including "wiring device manufacturing," "sheet metal work manufacturing," and "maintenance and repair construction of nonresidential structures." We allocated the cost of solar panels to "semiconductor machinery manufacturing" and remaining balance of plant expenses to "other electronic component manufacturing" and "power, distribution, and specialty transformer manufacturing." Wages for construction were taken from the report then adjusted for inflation and for the cost of living in Massachusetts relative to Vermont.[96] Following the IMPLAN industries specified for the Coolidge project, O&M included "insurance carriers," "employment and payroll of state govt, non-education" (for state and local permit fees). and "all other miscellaneous electrical equipment and component manufacturing" (for replacement of inverters). The lease payments made to landowners for the Coolidge project in Vermont were assumed to pass through to landowners in Massachusetts in a similar manner. This amounted to $5,415 per MW per year which was assumed to pass through to Massachusetts residents.

Small-scale solar

Residential and commercial installations are quite different from utility-scale installations. Small-scale projects are usually installed on a rooftop instead of in a field, where many utility-scale installations sit. The percentage of project costs spent on each material vary significantly from large-scale projects, due in part to economies of scale. We relied on data from the Solar Action Alliance[97] and a report by the U.S. DOE on the breakdown of costs for a small-scale system.[98] We allocated these costs using some of the same IMPLAN sectors as we used for large-scale projects as well as costs for marketing and other business overhead.

Battery storage

Most of the spending on the installation and operations of battery storage is composed of the battery and hardware. The *State of Charge* study conducted for Massachusetts DOER and CEC provided a breakdown of IMPLAN sectors relevant to battery storage, including: "all other

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[95] Tommy Vitolo, PhD, Maximilian Chang, Tyler Comings, and Avi Allison. Economic Benefits of the Proposed Coolidge Solar I Solar Project. Synapse Energy Economics. Prepared for Coolidge Solar I, LLC. November 3, 2015. p.9-12. http://www.synapse-energy.com/sites/default/files/Coolidge-Solar-Report-15-104.pdf

[96] Cost of living adjustment to Massachusetts wages used the median household income in Massachusetts divided by the median household income in Vermont. American Factfinder: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk

[97] Solar Action Alliance. How Much Will the Whole Installation Cost Me? https://solaractionalliance.org/residential-solar-panel-cost/.

[98] U.S. DOE. Office of Energy Efficiency & Renewable Energy. Soft Costs 101: The Key to Achieving Cheaper Solar Energy. February 25, 2016. https://www.energy.gov/eere/articles/soft-costs-101-key-achieving-cheaper-solar-energy

miscellaneous electrical equipment and component manufacturing," "storage battery manufacturing," and "electric power transmission and distribution."[99] We used the latter industry to model construction and O&M labor and the former two industries to model the construction and O&M supplies needed for a battery storage project.

Natural gas

We also modeled natural gas combined cycles (NGCC) and combustion turbines (NGCT) as separate resources, where applicable. The construction of both types of natural gas facilities used the default IMPLAN sector for power plant construction. O&M for renewable resources is nearly all fixed costs ("fixed O&M" or "FOM"), little to no non-fuel variable costs ("non-fuel variable O&M" or "non-fuel VOM") and no fuel costs. For natural gas, we modeled fuel, FOM, and non-fuel VOM separately. Labor costs at natural gas plants are primarily fixed costs: the number employed at the plant does not change significantly if the plant is operational. Therefore, in our modeling, the direct jobs only fluctuate with changes in FOM—such as when a unit is retired or a new unit is brought on line. For FOM, we used a combination of the default IMPLAN fossil fuel generation sector and a Brattle Group study on the economics of natural gas.[100] The Brattle study provided a breakdown of labor spending as a percentage of all FOM for NGCC's and NGCT's separately. Taking the spending from IMPLAN's fossil fuel sector, we removed all fuel spending (this was modeled separately). Spending on FOM non-labor included "pipeline transportation," "maintenance and repair construction of nonresidential structures" and "turbine and turbine generator set units manufacturing." Natural gas fuel was modeled separately using IMPLAN's default natural gas extraction sector. Non-fuel VOM spending was modeled as chemical manufacturing and waste management.

Biomass

There was no new biomass built in Massachusetts in our CE Future scenario. Therefore, there were no construction impacts for this resource. Similar to natural gas, we modeled biomass FOM, fuel, and non-fuel VOM separately. For biomass FOM, we used the IMPLAN fossil fuel generation sector and extracted all fuels and pipeline transportation. Fuel was modeled separately using IMPLAN's logging sector. Non-fuel VOM, like natural gas, was modeled as spending on chemicals and waste management.

Electric vehicle infrastructure

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[99] State of Charge: Massachusetts Energy Storage Initiative Study. p. 221. https://www.mass.gov/files/2017-07/state-of-charge-report.pdf.

[100] Newell, Samuel A. et al. Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM. Brattle Group. Prepared for PJM Interconnection LLC. May 15, 2014. p.33-34. http://files.brattle.com/files/6068_cost_of_new_entry_estimates_for_combustion_turbine_and_combined_cycle_plants_in_pjm.pdf

Only the high electrification sensitivity includes economic impacts from EV's; the number of EV's is the same in all other cases (including the business-as-usual). In the high electrification sensitivity, we assume a more aggressive trajectory of EV adoption in Massachusetts. EVs are not produced in Massachusetts. Shifting towards more EV adoption, however, will necessitate the addition of supporting infrastructure—mainly in the form of charging stations. We modeled the economic impacts of installing several types of charging: Level 1, Level 2 and DC charging units. The number of stations installed is based on studies on EV charging from NREL and Rocky Mountain Institute.

NREL conducted a study of Massachusetts adopting 300,000 EV's—concluding that the state would need 138 Level 1 chargers and 83 Level 2 chargers per 1,000 EV's on the road.[101] In our high electrification sensitivity, we add more than 1 million EV's in the state by 2030. The first 300,000 EV's were assumed to need the amount of Level 1 charging laid out in the NREL report on Massachusetts. We also used another NREL study of national EV adoption to project the amount of Level 2 and DC chargers needed.[102] We used the average Level 2 chargers per 1,000 EV's from the two reports and the level of DC chargers per 1,000 EV's from the national study. The costs for each charging technology are based on research by the Rocky Mountain Institute (RMI).[103] The RMI study also provided a breakdown of labor and materials costs that we translated into IMPLAN sectors for each EV charging type, including: "other communication and energy wire manufacturing," "power, distribution, and specialty transformer manufacturing," and "construction of new power and communication structures."

Electric vehicles reduce gasoline spending and increase electric demand. We account for changes in spending on both (described below). We do not, however, estimate job losses from reduced gasoline consumption. Much of gasoline purchasing is already automated, so reduced demand should have little effect on jobs—other than for towns that require full service. In addition, we have not accounted for the positive, yet small, impact of jobs related to operating EV charging stations after they are built. We expect that any loss or gain from jobs in these two activities would be small and difficult to estimate with precision.

Heat pumps

In the high electrification sensitivity, we assume that heat pumps account for an increasing amount of residential thermal heating load. We account for the effects of spending on heating from

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[101] Eric Wood, Sesha Raghavan, Clément Rames, Joshua Eichman, and Marc Melaina. Regional Charging *Infrastructure for Plug-In Electric Vehicles: A Case Study of Massachusetts.* p.25. https://www.nrel.gov/docs/fy17osti/67436.pdf

[102] Eric Wood, Clément Rames, Matteo Muratori, Sesha Raghavan, and Marc Melaina. *National Plug-In Electric Vehicle Infrastructure Analysis.* September 2017. https://www.nrel.gov/docs/fy17osti/69031.pdf

[103] Agenbroad, Josh and Ben Holland. *Pulling Back the Veil on EV Charging Station Costs.* Rocky Mountain Institute. April 29, 2014. https://rmi.org/news/pulling-back-veil-ev-charging-station-costs/

increased electricity spending and decreased spending on oil and natural gas. We assumed that avoided natural gas usage would not change job activity in Massachusetts since it would result in less gas distribution but more electric distribution. For oil usage, however, there are direct implications for oil delivery jobs in the Commonwealth: less labor will be required as a result of more electric heating. The economic impact on Massachusetts oil delivery jobs was based on the reduced oil usage (due to heat pumps) and the share of all liquid fuel sales that were due to residential heating.[104] This percentage was applied to the amount of existing fuel delivery jobs in Massachusetts to arrive at the amount of direct jobs lost. This number was then modeled in IMPLAN using the "truck transportation" sector. We did not model the activity of installing heat pumps as this would essentially replace the installation of other new heating and cooling units. The installation activities are similar and, as with the impacts of avoided gasoline, difficult to estimate with precision.

Customer costs

Revenue requirements for New England were provided by the Encompass model for each scenario we modeled. These represent the costs of market-supplied capacity and energy, policy compliance costs and capital costs for new resources that are passed on to Massachusetts ratepayers. They did not include transmission and distribution charges that would appear on the electric bill. Thus, we implicitly assume that these charges are equal across scenarios. For the induced impacts of electric bills, the revenue requirements are allocated to residential, commercial and industrial customers based on the share of retail sales to each sector in Massachusetts, as reported by utilities to the EIA.[105]

Lease payments from wind and solar projects made to landowners defrayed the collective electricity costs of Massachusetts residents. In the high electrification sensitivity, residents spend more on electricity but less on gasoline and heating fuel due to the addition of EVs and heat pumps, respectively. We projected the avoided heating costs based on the avoided natural gas and oil for residents (replaced by heat pumps) multiplied by the respective costs of each fuel provided in the EIA's Annual Energy Outlook.[106] Similarly, the avoided gasoline spending uses the EIA's projection of gasoline prices applied to the number of gallons displaced by EV's. Residents were assumed to save approximately 6 percent of any income, based on the average savings rate

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[104] U.S. Energy Information Administration. *New England - Energy Consumption by Sector and Source.* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2017&region=1-1&cases=ref2017 Note: Data for New England is not yet available for AEO 2018.

[105] U.S. Energy Information Administration. Form EIA-861. Annual Electric Power Industry Report. https://www.eia.gov/electricity/data/eia861/

[106] U.S. Energy Information Administration New England - Energy Consumption by Sector and Source. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2017&region=1-1&cases=ref2017 Note: Data for New England is not yet available for AEO 2018.

for the past ten years in the U.S.[107] The remaining savings, was assumed to be spent. We used the median household spending pattern in IMPLAN after removing spending on necessities such as healthcare, real estate, and utilities spending. Conversely, higher costs would lead residents to have less money available to spend on other discretionary items. Where applicable, these negative impacts were captured as well.

Businesses were assumed to absorb some of the savings on electricity costs and re-invest some of the savings. We used IMPLAN data for all commercial and industrial sectors to determine a share of savings that would be re-spent on hiring worker versus profits. For the commercial sector, we modeled the cost and savings from incremental behind-the-meter (BTM) solar—in the CE Future scenario and its sensitivities. Net savings were calculated assuming a ten-year solar loan at a 6.8 percent interest rate, a retail electric rate that increases with inflation (for avoided costs), and SREC revenue (based on SREC prices provided by SEA). The net savings or costs of owning this BTM solar decreases or increases costs to commercial customers, respectively.

REC price analysis

Over the last several years, many projects set in motion as a result of early renewable energy policies have achieved commercial operation, and are contributing material quantities of renewable energy to New England's electric system. These new additions include substantial volumes of distributed generation—a significant portion of which is behind the meter and has the dual effect of *increasing* REC supply and *decreasing* RPS-obligated load. At the same time, regional load forecasts have transitioned from projected increases to projected decreases over the next 10 years as a result of aggressive energy efficiency measures and penetration of behind-the-meter resources. As a result, RPS markets are expected to be in surplus in the near-term (2017 – 2018), as evidenced by the historically low Class 1 REC prices experienced at the conclusion of the 2017 trading year. Implementation of the Massachusetts Clean Energy Standard (CES), which begins in 2018, will add to Class 1 demand and is likely to result in increased REC prices until CES-eligible hydroelectric generation is deliverable to New England. Since the CES requirement "wraps around" the Massachusetts Class I RPS, the effect of a 3-percentage point target annual increase in Massachusetts Class I RPS is not felt until the cumulative Massachusetts Class 1 RPS target exceeds the cumulative CES target.

Beginning in 2022, CES-eligible hydroelectric power (assumed procured under Massachusetts Section 83D) is modeled to be delivered to New England. By 2023, this supply is assumed to dramatically exceed total (as opposed to incremental) Clean Energy Certificate (CEC) demand in all cases. At such time, the Class I RECs previously assumed to meet the incremental demand driven by the CES demand will revert to the Class I RPS market. In addition, incremental

[107] Federal Reserve St. Louis. Personal saving rate in the United States from 1960 to 2017. https://fred.stlouisfed.org/series/PSAVERT

legislation in Massachusetts, Connecticut, and Rhode Island has endowed the distribution utilities with long-term contracting authority. In conjunction with the existing Class 1 supply reversion, fulfillment of this authority without corresponding increases in RPS demand targets would create long-term market surpluses, suppressing REC prices after 2022, as shown in the business-as-usual scenario. By comparison, the 3-percent annual increase to RPS assumed as part of "CE Future" contributes to a more balanced market (i.e. supply does not dramatically exceed demand) and somewhat higher REC prices.

In "CE Future", the incremental supply contributed by additional offshore wind procurement (5 GW by 2035 compared to the current requirement of 1.6 GW by 2030) and removal of the net metering cap could match the incremental demand of 3-percent increases to the Massachusetts Class I RPS target. This would cause REC prices to settle in the $20 to $40 range during the 2023-2030 period.