Analysis of Massachusetts Electricity Sector Regulations

310 CMR 7.74: Reducing CO_2 Emissions from Electricity Generating Facilities

310 CMR 7.75: Clean Energy Standard

Electricity Bill and CO_2 Emissions Impacts

Massachusetts Executive Office of Energy and Environmental Affairs

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FORWARD

This Electricity Bill and CO_2 Emissions Impacts study is being published by the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) and the Massachusetts Department of Environmental Protection (MassDEP) as *Appendix A* to the document titled *Response to Comments on: 310 CMR 7.74 Reducing CO_2 Emissions from Electricity Generating Facilities [and] 310 CMR 7.75 Clean Energy Standard.*

The study, which was completed under contract by Synapse Energy Economics, Sustainable Energy Advantage, and Eastern Research Group, projects that the regulations will:

- Reduce carbon dioxide emissions in Massachusetts and New England
- Support increased clean energy generation
- Complement existing Massachusetts clean energy policies
- Ensure expected emissions reductions from in-state power plants
- Increase electricity bills by no more than 1–2 percent

The regulations directly address GWSA emission reductions requirements by:

- Limiting carbon dioxide emissions from regulated in-state power plants to a level consistent with achieving the GWSA-mandated 2020 emissions limit
- Requiring the use of additional clean energy to serve electricity customers in Massachusetts, thereby reducing emissions from electricity imported to Massachusetts

Relevant comments and final policy decisions were shared with the study authors on an ongoing basis to ensure that the study accurately reflects the regulations that were finalized by EEA and MassDEP.

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EXECUTIVE SUMMARY

The Massachusetts Executive Office of Energy and Environmental Affairs and the Massachusetts Department of Environmental Protection have promulgated two new regulations that address the electric power sector: (1) a mass-based limit on emissions from in-state power plants which emit greenhouse gases (310 CMR 7.74) and (2) a Clean Energy Standard (310 CMR 7.75) which sets standards for the sale of clean electricity to consumers in Massachusetts. The agencies contracted Synapse Energy Economics, Sustainable Energy Advantage, and Eastern Research Group (the Project Team) to conduct modeling analysis of emissions and bill impacts of the two regulations.

The Project Team found that these regulations will result in carbon dioxide (CO_2) emission reductions in Massachusetts and throughout New England. At the same time, we found that, based on our analysis, the estimated retail bill impact of these regulations will not exceed $1.30 per month for residential customers or 1.5 percent per month of historical bills for all customer types.

Our findings are based on a combination of electric-sector dispatch modeling and renewable market modeling in which we compared a Reference Case and a Policy Case. The Reference Case models our best estimate of a business-as-usual future without the regulations while the Policy Case represents this same future with one change: the implementation of these regulations. We also examined other scenarios and sensitivities that could lead to higher bill impacts, including versions of the Reference Case and Policy Case under higher electricity sales. Throughout our analysis, we focused on greenhouse gas emissions impacts and retail bill impacts both in the near term and through 2030. Our analysis and findings follow.

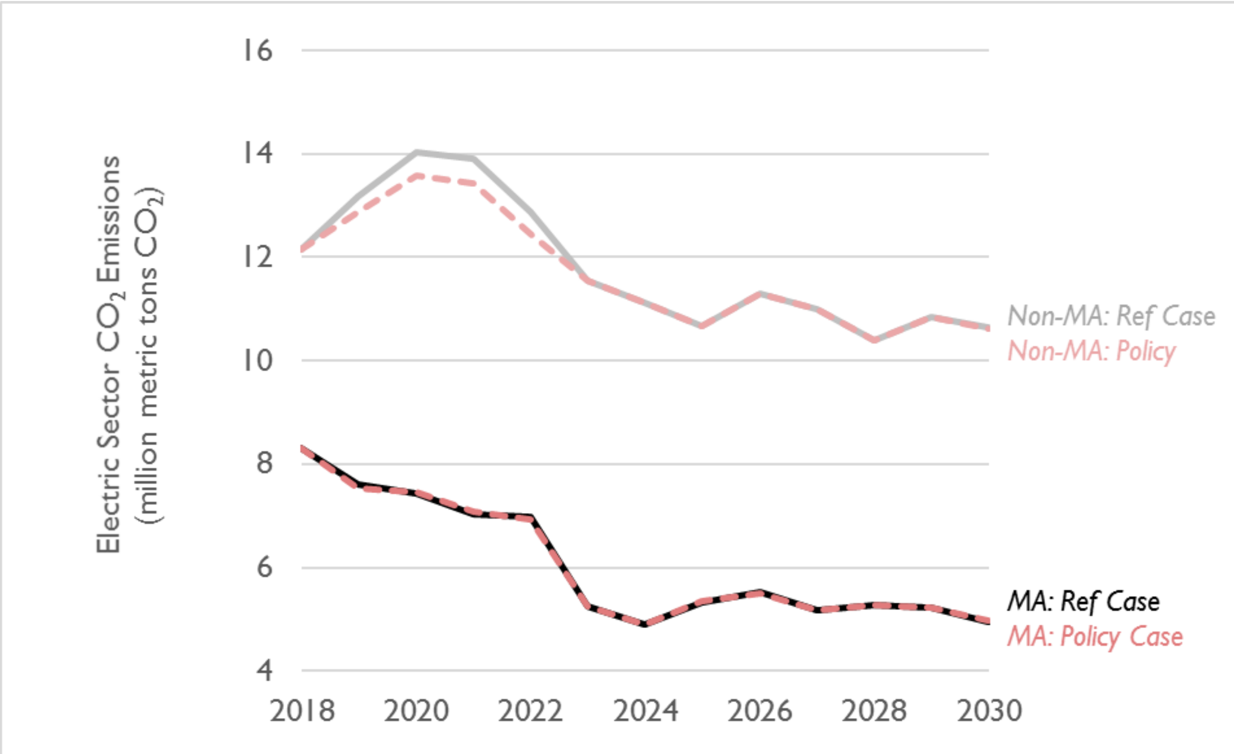
The new regulations reduce CO_2 emissions by 1.7 million metric tons regionwide, relative to a Reference Case.

Our Reference Case, which excluded the new regulations, projected decreasing electric sector emissions in Massachusetts and New England through 2030. Modeling showed that by 2020, electric-sector CO_2 emissions in Massachusetts decrease by an estimated 22 percent relative to 2016 emissions. By 2030, those emissions decrease by 43 percent relative to 2016 emissions as a result of already-planned changes to the electric system. These Reference Case circumstances included continued energy efficiency programs, renewable portfolio standards, and recently enacted requirements for utilities to enter into long-term contracts.

We found that in both the Reference Case and the Policy Case, annual CO_2 emissions are below the emissions limit established in 310 CMR 7.74. As a result, modeling showed that the price paid for CO_2 allowances issued pursuant to 310 CMR 7.74 could be as low as $0 per metric ton in each year. Furthermore, we found the Policy Case leads to a cumulative reduction of 40,000 metric tons CO_2 in Massachusetts between 2018 and 2030 relative to the Reference Case, a reduction of 0.1 percent (see ES-Figure 1).

While the Massachusetts-specific CO_2 emissions limit sets a maximum number of annual emissions for generators within Massachusetts, the Clean Energy Standard results in increases in generation from renewable resources located throughout New England. This additional renewable generation lowers CO_2 emissions in the other New England states, resulting in a cumulative region-wide decrease in CO_2 emissions of 1.7 million metric tons.

ES-Figure 1. CO_2 emissions from Massachusetts and non-Massachusetts electric power generators



We found that in an alternative sales forecast sensitivity in which annual electricity sales are higher in the near-term, the CO_2 limit under 310 CMR 7.74 is only binding in 2018, leading to an emissions reduction within Massachusetts of 4 percent. This results in a CO_2 price for allowances issued pursuant to 310 CMR 7.74 of $1.16 per metric ton in 2018, and a price of $0 per metric ton in all other years. As in the main scenarios, the Policy Case leads to emissions reductions both in Massachusetts and the other New England states. The expected result is a cumulative, region-wide reduction of 3.0 million metric tons.

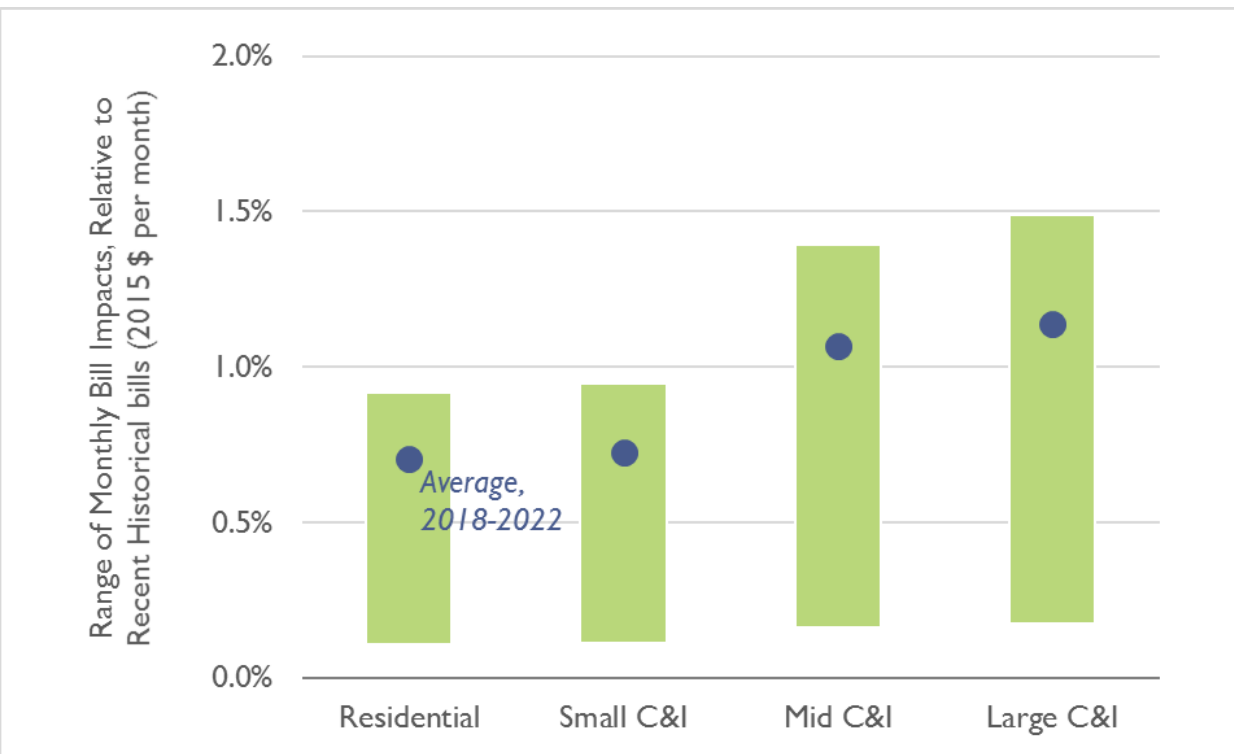
Implementing 310 CMR 7.74 and 7.75 results in monthly bill impacts of 0.1 to 1.5 percent.

We estimated changes to monthly retail electric bills impacts by calculating the aggregate impact of changes to wholesale energy market prices, wholesale capacity market prices, and spot market prices for Renewable Energy Certificates (RECs). Between 2018 and 2022, the regulations lower wholesale energy market prices by as much as 0.7 percent, largely resulting from additional renewable generation that has either near-zero variable operating costs or has operating costs met through payments associated with RECs. Because of this decrease in wholesale energy market prices, capacity prices increase during this period by as much as 1.4 percent as existing resources are forced to rely more heavily on the capacity market to compensate them for their fixed operational costs.

Because of increased demand for renewables driven by the Clean Energy Standard, our modeling showed that spot market prices paid for RECs in the Policy Case increase compared to the Reference Case between 2018 and 2022, but do not change from the Reference Case in 2023 and later years when new offshore wind and hydroelectric resources are available. Prices for RECs between 2018 and 2022 reach levels as high as $30 per megawatt-hour. This value represents 44 percent of the Massachusetts Renewable Portfolio Standard Alternative Compliance Payment price, which effectively serves as a cap on REC prices.

As a result of changes to wholesale energy and capacity prices and changes to REC prices, our modeling showed that the new regulations increase the typical residential customer's monthly electric bill by $0.14 to $1.22 between 2018 and 2022, relative to a future without the regulations. Relative to recent typical bills, this is an increase of 0.1 to 0.9 percent (see ES-Figure 2). Commercial and industrial customers, who in a given month may consume 10 to 1,000 times as much electricity as residential customers, see similar bill impacts, ranging from 0.1 to 1.5 percent. Our modeling found no relative bill impacts for any customers in any years between 2023 and 2030. This is due to increased availability of new offshore wind and hydroelectric resources, as well as actual operational emissions well below the CO_2 emission limits.

ES-Figure 2. Range of monthly bill impacts in 2018 through 2022, relative to recent historical bills



While wholesale energy and capacity market prices are relatively unchanged under a higher electricity sales forecast, the increased level of sales drives an increased demand for RECs, resulting in a higher spot market price for RECs between 2018 and 2022. This higher REC price results in larger bill impacts between the Reference Case and Policy Case, on the order of $1.72 per month for residential customers, but no more than 2.1 percent in any year for any customer type. As in the main scenarios, we did not observe bill impacts for any customers in any years between 2023 and 2030.

Conclusion

The new regulations are projected to reduce future CO_2 emissions in Massachusetts, relative to both today and a business-as-usual Reference Case. In addition, these regulations result in emissions reductions in the other New England states, and New England as a whole. At the same time, the regulations result in small bill increases for Massachusetts consumers, with monthly electric bill impacts only observed through 2022 and not exceeding 1.5 percent for any customer.

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1. INTRODUCTION

The Massachusetts Executive Office of Energy and Environmental Affairs and the Massachusetts Department of Environmental Protection have promulgated two new electric-sector regulations: (1) a mass-based limit on emissions from in-state power plants that emit greenhouse gases and (2) a Clean Energy Standard.[1] Synapse Energy Economics, Sustainable Energy Advantage, and Eastern Research Group (the Project Team) conducted modeling analysis of the two regulations. The Project Team found that these regulations will result in carbon dioxide (CO_2) emissions reductions in Massachusetts and throughout New England. We also estimated the relative retail bill impact of these regulations and found that it will not exceed $1.30 per month for residential customers. Further, the bill impact does not exceed 1.5 percent per month of historical bills for all customer types.

Our findings are based on electric-sector dispatch modeling and renewable market modeling in which we compared a business-as-usual Reference Case scenario and a Policy Case. Our Policy Case incorporates feedback from commenters on the regulations and represents a future in which the regulations are put into place. In addition, we examined several other scenarios and sensitivities to understand the Reference Case and Policy Case impacts. Throughout our analysis, we focused on greenhouse gas emissions impacts, wholesale energy price impacts, and retail bill impacts both in the near term and through 2030.

1.1 The Regulations

The following section details the modeling assumptions for each of the two regulations in this analysis.

310 CMR 7.74: Mass-based emissions limit on in-state power plants

310 CMR 7.74 assigns declining limits on total annual greenhouse gas emissions from identified emitting power plants within Massachusetts. Table 1 lists the affected power plants under 310 CMR 7.74. This list includes existing plants as well as other plants that are under construction and proposed plants expected to be subject to the regulation.[2] In this analysis, we modeled this regulation as a state-wide limit through which plants receive CO_2 allowances pursuant to 310 CMR 7.74 at the start of each year.[3]

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[1] More information on the regulations under Section 3(d) of the Massachusetts GWSA is available at http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html.

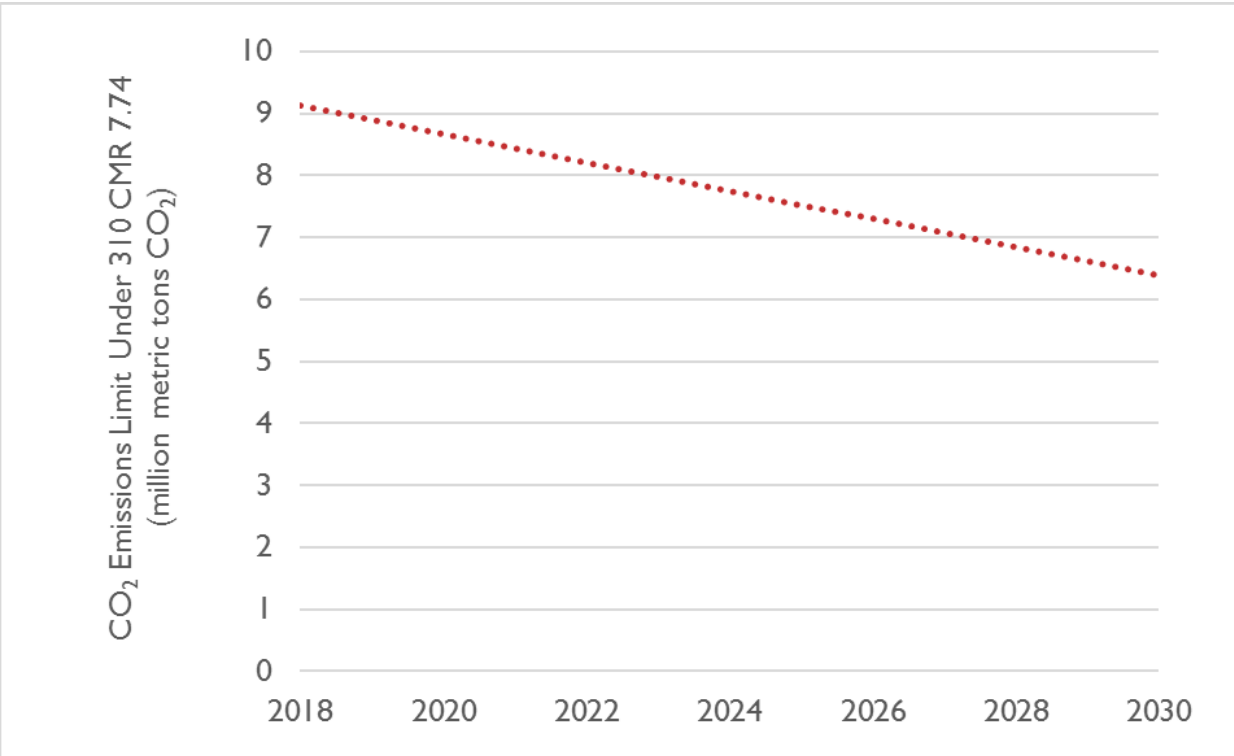
[2] More information on unit additions and retirements is available in Appendix A.

[3] We understand that allowances could be distributed through free allocation, through an auction, or through some combination thereof. We did not make a distinction between these approaches in this modeling analysis.

The emissions limit starts at 9.1 million metric tons in 2018. It then declines by 2.5 percent of the 2018 emissions limit to 8.7 million metric tons in 2020, and 6.4 million metric tons in 2030 (see Figure 1).[4]

In our analysis, we assumed that both new and existing units fall under the same aggregate limit. We modeled all new and existing units as able to fully trade allowances pursuant to 310 CMR 7.74 throughout each compliance year. We did not model any Alternative Compliance Payments (ACP) or banking of CO_2 allowances pursuant to 310 CMR 7.74.

Figure 1. Analyzed electric sector CO_2 limits



[4] Under the regulation, the emissions cap continues through 2050. For more information on this analysis' modeling scope, see Appendix A.

Table 1. List of generating units to be subject to 310 CMR 7.74

ORSPL	Facility	Unit Type	Fuel Type	Online Year (if new)	Unit Name
1588	Mystic	ST	Natural Gas	-	Mystic 7
1588	Mystic	CC	Natural Gas	-	Mystic CC
1592	Medway Station	GT	Oil	-	West Medway Jet
1595	Kendall Green Energy LLC	ST	Natural Gas	-	Kendall Square Jet
1595	Kendall Green Energy LLC	CC	Natural Gas	-	Kendall Square CC
1599	Canal Station	ST	Oil	-	Canal 1
1599	Canal Station	ST	Oil	-	Canal 2
1642	West Springfield	ST	Oil	-	West Springfield 3
1642	West Springfield	GT	Natural Gas	-	West Springfield 10
1642	West Springfield	GT	Natural Gas	-	West Springfield 1-2
1660	Potter	CC	Natural Gas	-	Potter Station 2
1660	Potter	GT	Natural Gas	-	Potter Station 2 GT
1678	Waters River	GT	Natural Gas	-	Waters River 1
1678	Waters River	GT	Natural Gas	-	Waters River 2
1682	Cleary Flood	ST	Oil	-	Cleary-Flood
1682	Cleary Flood	OT	Natural Gas	-	Cleary-Flood CC
6081	Stony Brook	CC	Oil	-	Stony Brook CC
6081	Stony Brook	GT	Oil	-	Stony Brook GT
10307	Bellingham	CC	Natural Gas	-	Bellingham Cogen
10726	MASSPOWER	CC	Natural Gas	-	Masspower
50002	Pittsfield Generating	CC	Natural Gas	-	Pittsfield
52026	Dartmouth Power	CC	Natural Gas	-	Dartmouth Power CC
52026	Dartmouth Power	GT	Natural Gas	-	Dartmouth Power GT
54586	Tanner Street Generation, LLC	CC	Natural Gas	-	L'Energia Energy Center
54805	Milford Power, LLC	CC	Natural Gas	-	Milford Power (MA)
55026	Dighton	CC	Natural Gas	-	Dighton Power
55041	Berkshire Power	CC	Natural Gas	-	Berkshire Power
55079	Millennium Power Partners	CC	Natural Gas	-	Millennium Power
55211	ANP Bellingham Energy Company, LLC	CC	Natural Gas	-	ANP Bellingham
55212	ANP Blackstone Energy Company, LLC	CC	Natural Gas	-	ANP Blackstone
55317	Fore River Energy Center	CC	Natural Gas	-	Fore River
1626	Footprint (Salem Harbor)	CC	Natural Gas	2017	Salem Harbor CC
1599	Canal 3	GT	Natural Gas	2019	Canal GT
59882	Exelon West Medway II LLC	GT	Natural Gas	2018	West Medway II

310 CMR 7.75: Clean Energy Standard

The Project Team also analyzed a second regulation, 310 CMR 7.75, that establishes a Clean Energy Standard for Massachusetts load-serving entities. This regulation requires load-serving entities in Massachusetts which are currently obligated to meet Class I Renewable Portfolio Standards (RPS) requirements to also purchase additional specified amounts of electricity from eligible clean energy resources in future years. In this regulation, certain types of resources are eligible to produce Clean Energy Certificates (CECs) which may be sold to obligated entities for compliance with the Clean Energy Standard, mirroring the role of RECs within the RPS.

Under this regulation, resources eligible to produce CECs must:

(1) Be located in the ISO New England region or an adjacent control area (capable of delivering the energy into the ISO New England control area), or have a dedicated transmission line—with a commercial operation date after December 31, 2016—for delivering the clean energy;

(2) Have a commercial operation date after December 31, 2010; and

(3) Must also fulfill one of the following conditions:

  a. be qualified as an RPS Class I renewable generation unit pursuant to 225 CMR 14.06(3), or

  b. have net lifecycle GHG emissions that are at least 50 percent lower than a new natural gas-fired combined cycle facility.[5]

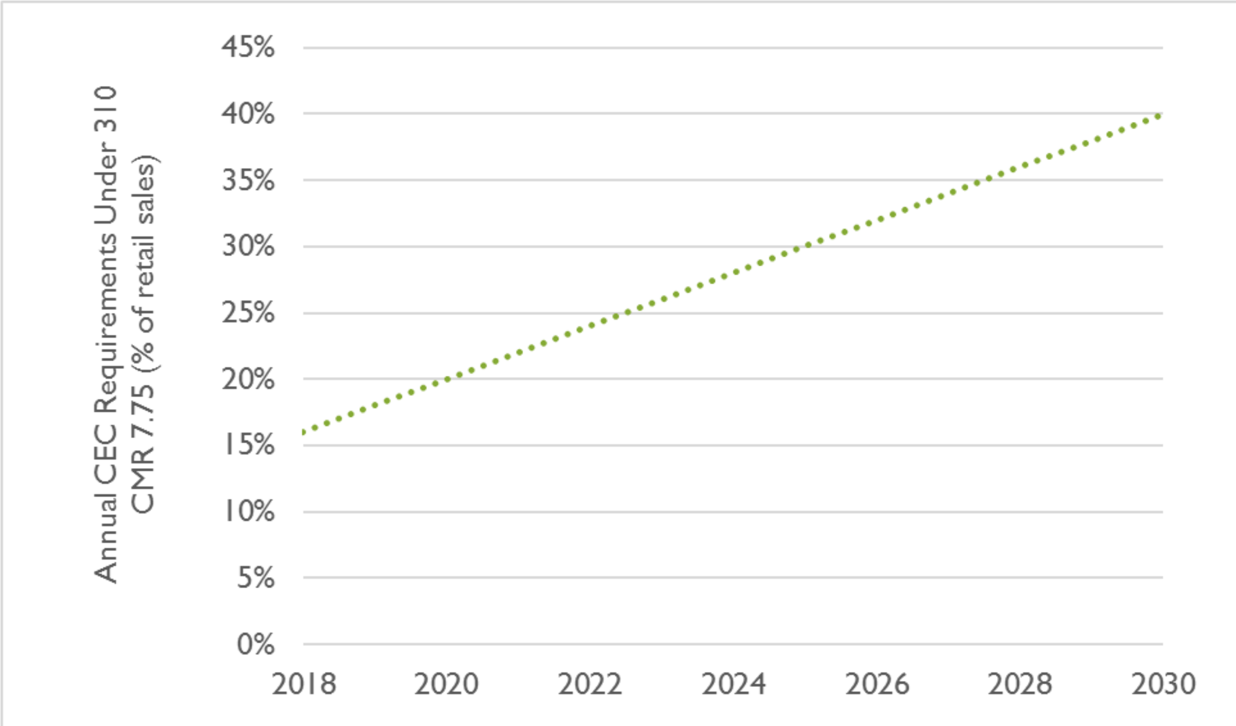
A generation unit that does not satisfy the applicable fuel, energy resource, or technology-specific provisions or limitations (in 225 CMR 14.05(1)(a)5.a–c, 6.b–g, or 7.a–g) may not qualify as a clean generation unit unless it is a hydroelectric generator that does not satisfy the limitation in 225 CMR 14.05(1)(a)6.a. Certificates used for Clean Energy Standard compliance must not have been retired in satisfaction of any other obligation or claim in jurisdictions other than Massachusetts.

For this analysis, we assumed the Clean Energy Standard would cover all electricity sales by distribution utilities and competitive suppliers, with the exception of municipally owned utilities. For the purposes of this analysis, the only resources eligible for compliance under the Clean Energy Standard are RPS Class I resources and new large hydro resources delivered over new transmission lines. In our modeling, the Clean Energy Standard begins at 16 percent per year for all retail sellers (except municipal light boards and electric departments) and increases at 2 percent per year until 40 percent in 2030.[6] In this analysis, we assumed that the ACP for CECs is fixed at 50 percent of the Massachusetts Class I ACP.

[5] Specifically, an eligible resource must have net lifecycle GHG emissions that are at least 50 percent lower, over a 20-year period, per unit of useful energy relative to the lifecycle greenhouse gas emissions from the aggregate use of the operation of a new combined-cycle natural gas electric generating facility with the most efficient commercially available technology as of the date of the statement of qualification application.

[6] Clean Energy Standard compliance continues through 2050, reaching a level of 80 percent in that year.

Figure 2. Clean Energy Standard annual requirements



1.2 Analytical Methodology

This analysis quantified incremental impacts of the regulations by estimating the potential change in wholesale market prices (including energy and capacity prices), REC and CEC prices, CO_2 allowance prices pursuant to 310 CMR 7.74, monthly retail bill impacts, capacity, generation, and electric-sector CO_2 emissions for each modeled scenario compared to a reference or business-as-usual case. The main scenarios analyzed include:

- **Reference Case:** This scenario assesses a business-as-usual future in which no changes are made to existing laws and regulations in Massachusetts or any other New England state. Specifically, this scenario models a future in which the new policies regarding unit-specific emissions limits and the Clean Energy Standard under 310 CMR 7.74 and 7.75 are not implemented.

- **Policy Case with new regulations:** This scenario is the same as the Reference Case with two exceptions: (1) it assumes that the annual CO_2 emission limits on electric generators under 310 CMR 7.74 are in effect, and (2) it assumes that the Clean Energy Standard under 310 CMR 7.75 is in effect.

For both scenarios, we utilized Sustainable Energy Advantage's REMO model to estimate renewable builds and REC prices, and Anchor Power Solution's EnCompass model to estimate unit-level dispatch, capacity expansion, generation, emissions, wholesale market prices, and CO_2 allowance prices pursuant to 310 CMR 7.74. While REMO and EnCompass are distinctly separate modeling tools, they were deployed in concert for this analysis. Through an iterative process, projected renewable energy buildouts and REC prices from the REMO model were used as inputs in the EnCompass estimation of wholesale energy and capacity prices. These forecasts were fed back into REMO to inform final renewable energy build-outs, REC prices and total REC expenditures by retail customers, and re-run through EnCompass to arrive at final values of wholesale energy and capacity prices, unit dispatch, and CO_2 emissions. At the end of this process, we integrated output data from REMO and EnCompass in a custom-built spreadsheet-based bill impact model to estimate the monthly retail bill impacts for a variety of different Massachusetts customer classes.

Importantly, both scenarios feature the same assumptions with respect to non-policy inputs. These include:

- **Electricity sales forecasts:** Both the Reference Case and Policy Case assume the same amount of electricity sales increases, energy efficiency, and vehicle electrification in any given year. The main electricity sales forecast used in this analysis is based on an econometric forecast of electricity sales from ISO New England, adjusted by Synapse to reflect the most up-to-date estimates of energy efficiency, and to include a forecast of electric vehicle deployment in Massachusetts in line with the 2015 update to the *Massachusetts Clean Energy and Climate Plan for 2020*.[7]

- **Natural gas prices:** Both scenarios use the same forecast for natural gas prices, based on a synthesis of NYMEX futures and the Energy Information Administration (EIA)'s latest Annual Energy Outlook (AEO).

- **Other resource costs:** In addition to assuming the same natural gas price, both scenarios use the same assumptions for other fuel costs, new capital costs, and operation and maintenance costs.

- **Known power plant additions:** Both scenarios assume that a number of new power plants will be constructed in the next several years, based on under-construction data from EIA databases and cleared resources in the New England Forward Capacity Market.

- **Known power plant retirements:** Both scenarios assume that power plants that are currently announced to be retired cease generating power on their announced retirement date; neither scenario assumes that any other power plants retire during the study period.

- **Renewable portfolio standards:** Both scenarios assume that annual increases to state RPS—both in Massachusetts and other states—remain consistent with current policies into the future; neither scenario assumes that RPS policies are adjusted beyond what is known today.

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[7] This main electricity forecast (i.e., the "Synapse forecast") is similar to, but not derived from or based on the sales forecast used in the 2015 update to the CECP, with the exception of the electric vehicle deployment component. More information on the 2015 update to the CECP is available at http://www.mass.gov/eea/waste-mgnt-recycling/air-quality/climate-change-adaptation/mass-clean-energy-and-climate-plan.html.

- **Other renewable, storage, and long-term contracting policies:** Both the Reference Case and the Policy Case assume that long-term contracting obligations issued by Massachusetts states are fulfilled. This includes:

    - A requirement under Massachusetts Chapter 188 of the Acts of 2016, an Act to Promote Energy Diversity ("Chapter 188") Section 83D for Massachusetts distribution utilities to solicit long-term contracts for clean energy generation (including firm service hydroelectric and/or new Class I RPS supply) for a quantity equivalent to 9.45 TWh per year,

    - Requirements under Massachusetts Chapter 188 Section 83C for these entities to solicit long-term contracts for 1600 MW of offshore wind, and

    - Adoption of goals issued by Massachusetts Department of Energy Resources (MA DOER) of 200 MWh of energy storage by 2020.

- **Intra-regional transmission additions:** Both scenarios assume new transmission buildouts consistent with those assumed in preparation for the ISO New England in the 11th Forward Capacity Auction Zone formation process.

- **Regional Greenhouse Gas Initiative (RGGI) allowance prices:** Both scenarios assume that the price paid for RGGI allowances in each year follow the same trajectory based on recent modeling by ICF International.[8]

Other scenarios and sensitivities

In addition to the two main scenarios discussed above, we assessed the impact of changing several key assumptions on costs and emissions. We also explored the sensitivity of costs and emissions to different policy scenarios (see Table 2). Specifically, we assessed the following variations:

- **Alternative electricity sales forecast:** We examined the cost and emissions impacts under a separate sales forecast trajectory which projects higher electricity sales in near-term years. This separate forecast closely follows the 2017 CELT forecast released by ISO New England in May 2017 (including the effects of both econometric sales growth and energy efficiency), but also includes the same level of incremental Massachusetts electric vehicle deployment applied in the Synapse forecast.

- **More stringent CO_2 limits:** We assessed a policy case in which, rather than starting at 9.1 million metric tons 2018, the CO_2 emissions limit on power plants starts at 7.4 million metric tons in 2018. It then declines by 2.5 percent in every subsequent year.

- **High natural gas price:** We examined a sensitivity in which natural gas prices followed a separate long-term trajectory, arriving at 2030 prices 50 percent higher than in the main scenarios.

[8] See https://www.rggi.org/design/2016-program-review/rggi-meetings for more information about ongoing RGGI modeling.

- **Alternative RGGI price:** After the release of new RGGI modeling by ICF International on June 22, 2017, we conducted additional modeling to assess the sensitivity of our analysis to different RGGI prices.

Additional details on the models used, input assumptions, and modeled scenarios are available in Appendix A and Appendix B.

Table 2. Modeled scenarios

	Description	Sales Forecast	Gas Price	RGGI Price	Regulations
Main Scenarios					
Reference Case	BAU future with no new regulations	Synapse forecast	Medium	April 2016 RGGI modeling runs	None
Policy Case	Future with new regulations	Synapse forecast	Medium	April 2016 RGGI modeling runs	Limit of 9.1 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year
Other Scenarios					
Reference Case, Alternative sales forecast	BAU future with no new regulations and alternative sales forecast	ISO New England	Medium	April 2016 RGGI modeling runs	None
Policy Case, Alternative sales forecast	Future with new regulations and alternative sales forecast	ISO New England	Medium	April 2016 RGGI modeling runs	Limit of 9.1 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year
Stringent Limit Case	Future with new regulations, including a more stringent CO_2 limit	Synapse forecast	Medium	April 2016 RGGI modeling runs	Limit of 7.4 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year
Stringent Limit Case, Alternative sales forecast	Future with new regulations, including a more stringent CO_2 limit and alternative sales forecast	ISO New England	Medium	April 2016 RGGI modeling runs	Limit of 7.4 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year
Policy Case, High gas price	Future with new regulations and a high natural gas price	Synapse forecast	High	April 2016 RGGI modeling runs	Limit of 9.1 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year
Policy Case, Alternative RGGI price	Future with new regulations and a different RGGI price	Synapse forecast	Medium	June 2017 RGGI modeling runs	Limit of 9.1 $MMTCO_2$ in 2018 declining by 2.5% per year; CES grows at 2% per year

Note: We analyzed two separate Policy Cases, one with a Clean Energy Standard ACP set to 50 percent of the Class I RPS ACP, and one with a Clean Energy Standard ACP set to 100 percent of the Class I RPS ACP. However, in the 50 percent ACP version, there was no year in which the REC/CEC price exceeded 50 percent of the Class I RPS ACP, making it a non-binding constraint. As a result, these two versions of the Policy Case were found to be identical in terms of renewable builds, generation, emissions, and cost impacts.

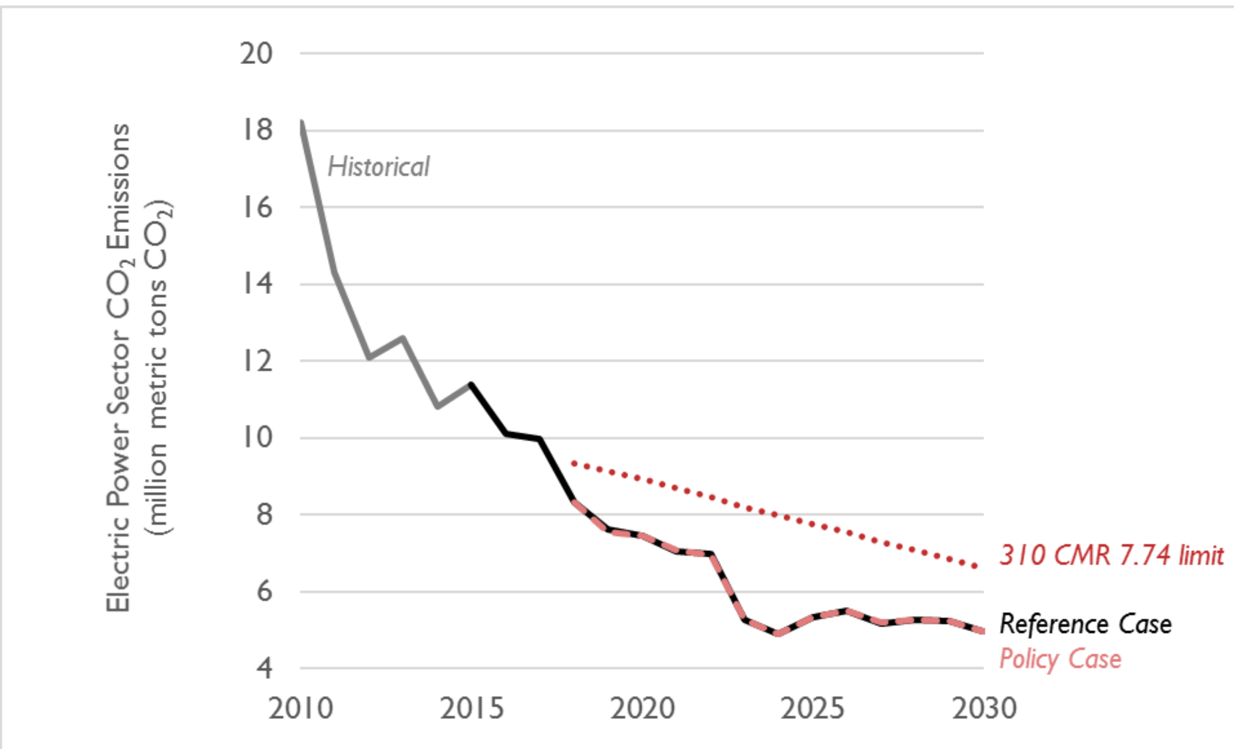
2. MAIN FINDINGS

This chapter details our primary findings, with a focus on the Reference Case and the Policy Case.

2.1 Impacts on CO_2 emissions

We found that although 310 CMR 7.74 establishes a limit on CO_2 emissions from Massachusetts electric power generators beginning in 2018, there is no year in the Policy Case in which CO_2 emissions exceed the limit (see Figure 3). In fact, even in the Reference Case, CO_2 emissions from Massachusetts electric power generators remain below the CO_2 limit in every year. Note that Figure 3 includes CO_2 emissions both from affected generators and other fossil-fired generators located in Massachusetts that are not subject to the CO_2 limit specified 310 CMR 7.74, though these unaffected generators constitute only 2.5 to 4.9 percent of CO_2 emissions in any given year.[9]

Figure 3. CO_2 emissions from Massachusetts electric power generators



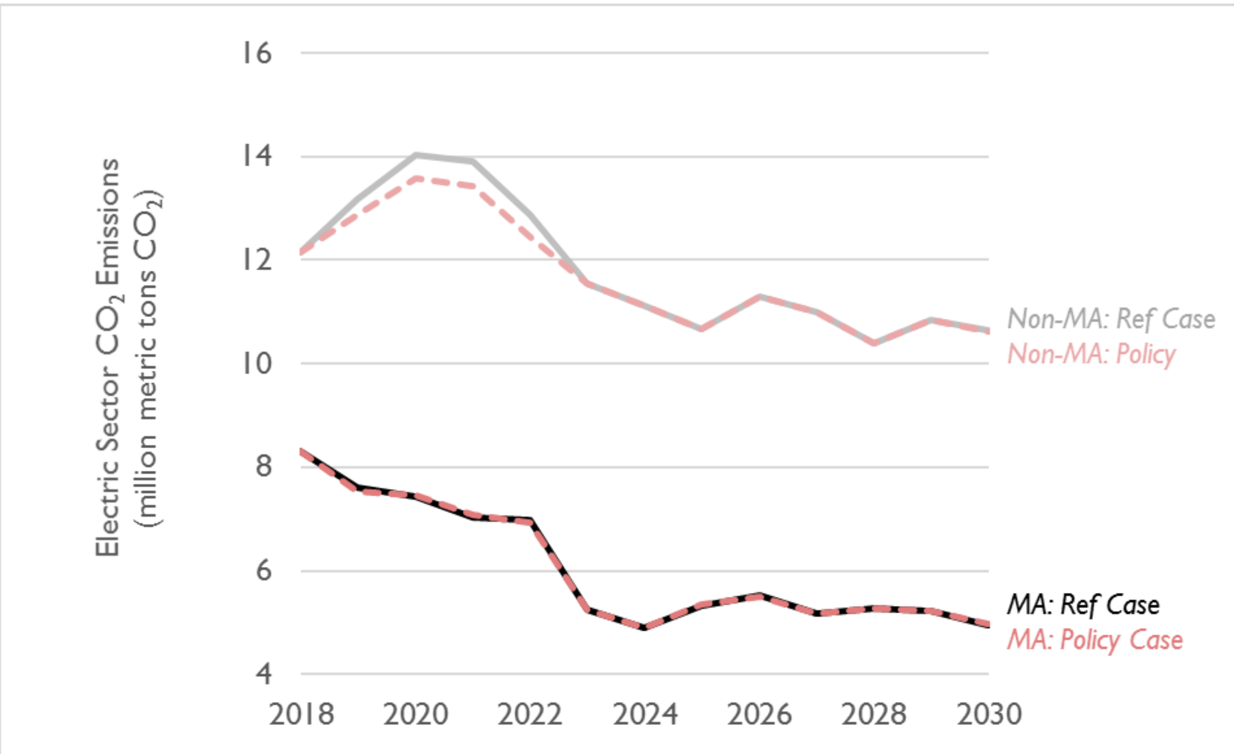
Notes: The CO_2 limit under 310 CMR 7.74 is binding when modeled emissions are equal to the regulatory limit, shown with the dotted line. This figure's y-axis is truncated at 4 million metric tons CO_2.

[9] This analysis does not quantify greenhouse gas emissions from biomass and municipal solid waste resources. MassDEP accounts for emissions from these resources separately under the Massachusetts Greenhouse Gas Inventory.

Although there is no year in which the CO_2 limit is binding, between 2018 and 2030, Massachusetts' cumulative CO_2 emissions in the Policy Case are lower than in the Reference Case by 40,000 metric tons, or 0.1 percent. Most of this decrease in emissions occurs between 2019 and 2022, and it is attributable to incremental renewable generation driven by the Clean Energy Standard in years before the assumed large hydroelectric imports are operational.

This decrease in emissions is not limited to Massachusetts. The incremental renewables driven by the Clean Energy Standard cause emissions to fall throughout New England (see Figure 4). Across all six New England states, CO_2 emissions between 2018 and 2030 fall by 1.7 million metric tons in the Policy Case relative to the Reference Case, a decrease of 0.7 percent. Of the total relative change in emissions, 2 percent occurs in Massachusetts. In 2019, the year with the largest observed decrease in emissions, Policy Case CO_2 emissions in Massachusetts are lower than the Reference Case CO_2 emissions by 0.9 percent.

Figure 4. CO_2 emissions from Massachusetts and non-Massachusetts electric power generators



Note: This figure's y-axis is truncated at 4 million metric tons CO_2.

2.2 Impacts on generation and dispatch

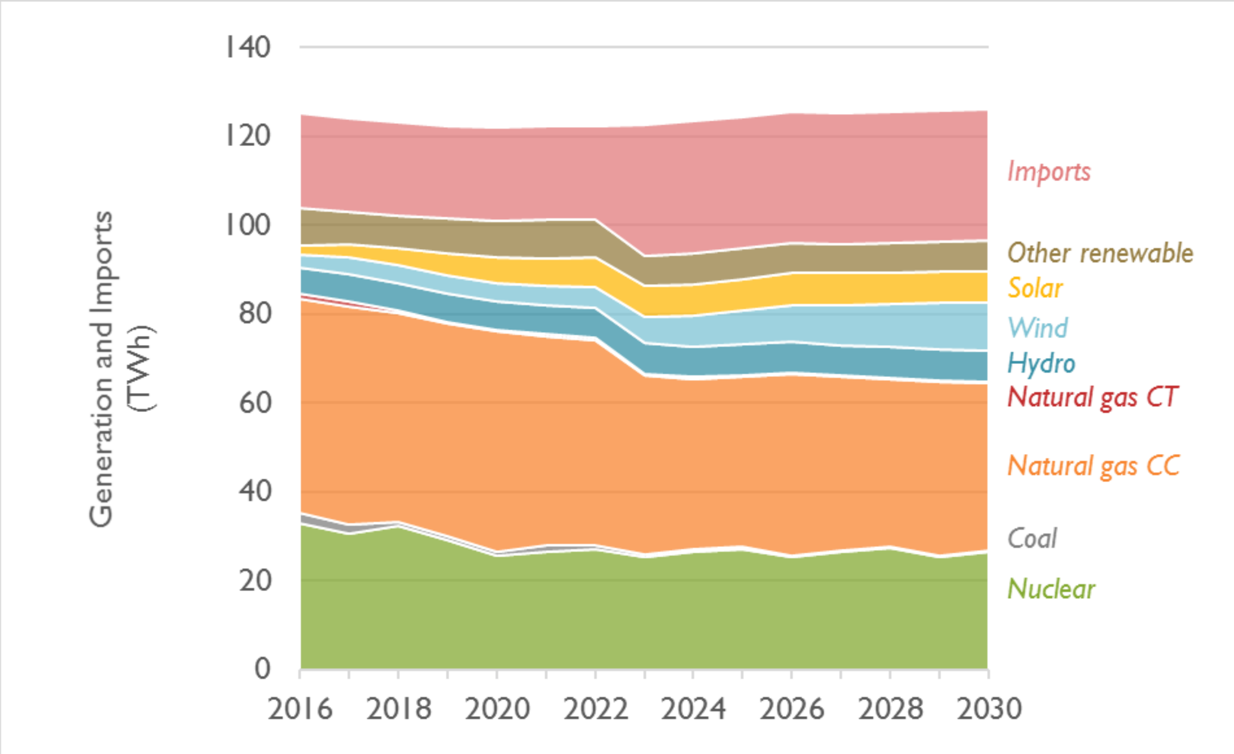
The fact that there are only small differences in emissions in the Reference Case and the Policy Case is a direct result of the comparatively larger changes to the New England electric system that are expected regardless of the new regulations. Figure 5 shows the expected sources of electricity in New England in future years. Though this figure shows these values for the Policy Case, the Reference Case is similar, with the exception of a 3 percent increase in renewable generation in 2018 to 2022 and a corresponding decrease in natural gas generation during the same period. Over the entire analysis period, we observed three main drivers that result in diminishing fossil generation, and as a consequence, decreased emissions:

- **Increased renewables:** As a result of (1) RPS policies throughout New England (and boosted by the Clean Energy Standard in the Policy Case) and (2) long-term contracting requirements for renewables under Massachusetts' Chapter 188 and other laws, renewable generation is expected to grow substantially between 2016 and 2030. In 2016, renewables (including solar, wind, hydro, biomass, municipal solid waste, and other renewables) constituted about 19 percent of New England's electricity generation; by 2030, this percentage is expected to grow to 33 percent.
- **Increased imports of electricity:** In 2016, imports of electricity from adjoining electric systems in New York and Canada constituted 17 percent of New England's electricity demand. In 2030, this percentage is assumed to grow to 23 percent. Although some new electric imports are eligible to receive CECs under the Clean Energy Standard, these imports are also required under Massachusetts' Chapter 188. Thus, they would exist under the Reference Case as well as the Policy Case.[10]
- **Flat electric sales:** Our analysis of expected sales, energy efficiency, and expected electric vehicle deployment assumes that the annual energy demand for electricity in New England is likely to grow by just 1 percent between 2016 and 2030.

Given the increase in renewables and imports, as well as a largely static demand for electricity, electricity generation from fossil generators is estimated to decrease by 1 percent by 2020, relative to 2016 levels. By 2030, fossil generation will decrease by 25 percent. As fossil generation decreases in the Reference Case, so too do CO_2 emissions from fossil generators, resulting in the observations described above.

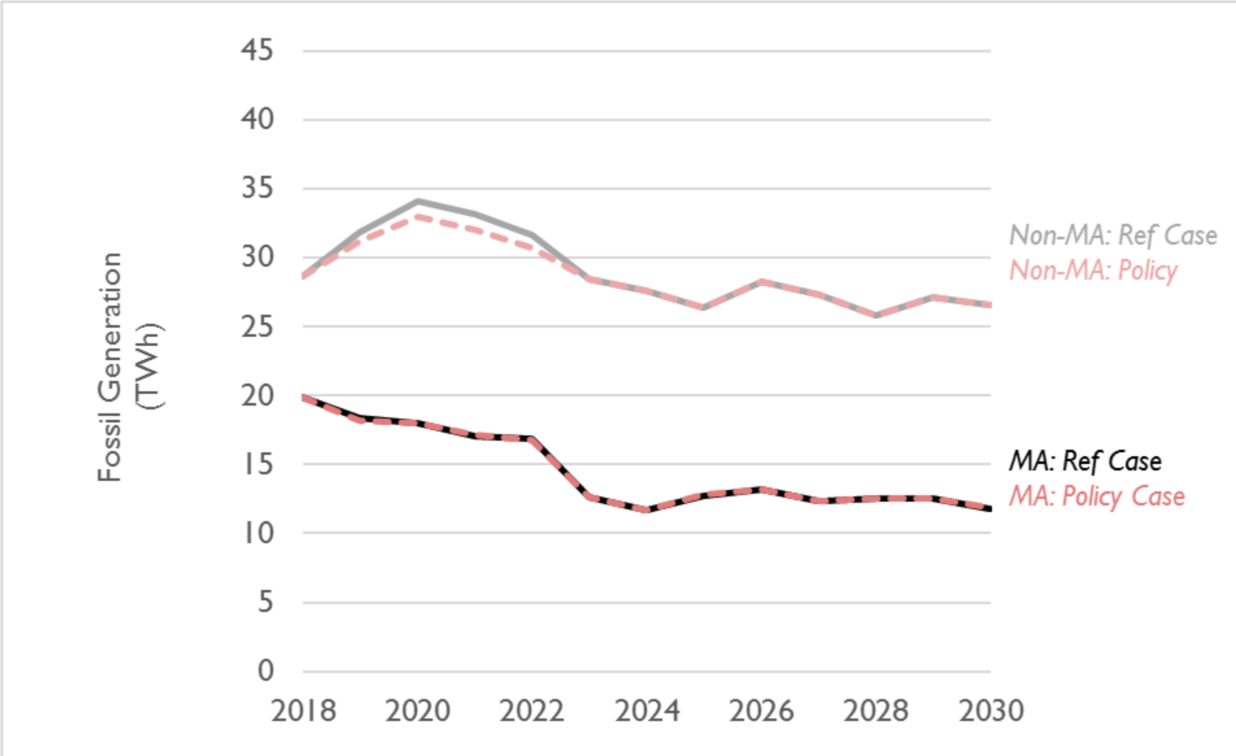
[10] Only imported electricity that is transmitted over transmission lines built on or after January 2017 is eligible to qualify for CECs. As a result, we assume that all new imports required by Massachusetts Chapter 188 are incremental to existing imports. We assume that net imports over existing transmission lines remain constant in all future years, although the resource composition of these imports may change from year-to-year.

Figure 5. New England-wide electricity generation and net imports in the Policy Case



Note: In this figure, the "other renewable" capacity includes battery storage, biomass, biogas, biodiesel, fuel cells, landfill gas, low emission advanced renewables, municipal solid waste, and tidal energy. Note that "hydro" in this chart does not include hydroelectric power imported from outside New England. "Natural Gas" includes generation produced from both natural gas and petroleum that is consumed at primarily natural gas-fired power plants.

Figure 6. Fossil generation from Massachusetts and New England electric power generators



2.3 Impacts on wholesale and retail prices

Changes to the regional electric system that are expected even without the new regulations will have a noticeable impact on generation and CO_2 emissions, as well as corresponding impacts on wholesale and retail prices. Our modeling showed the following additional impacts due to the new regulations.

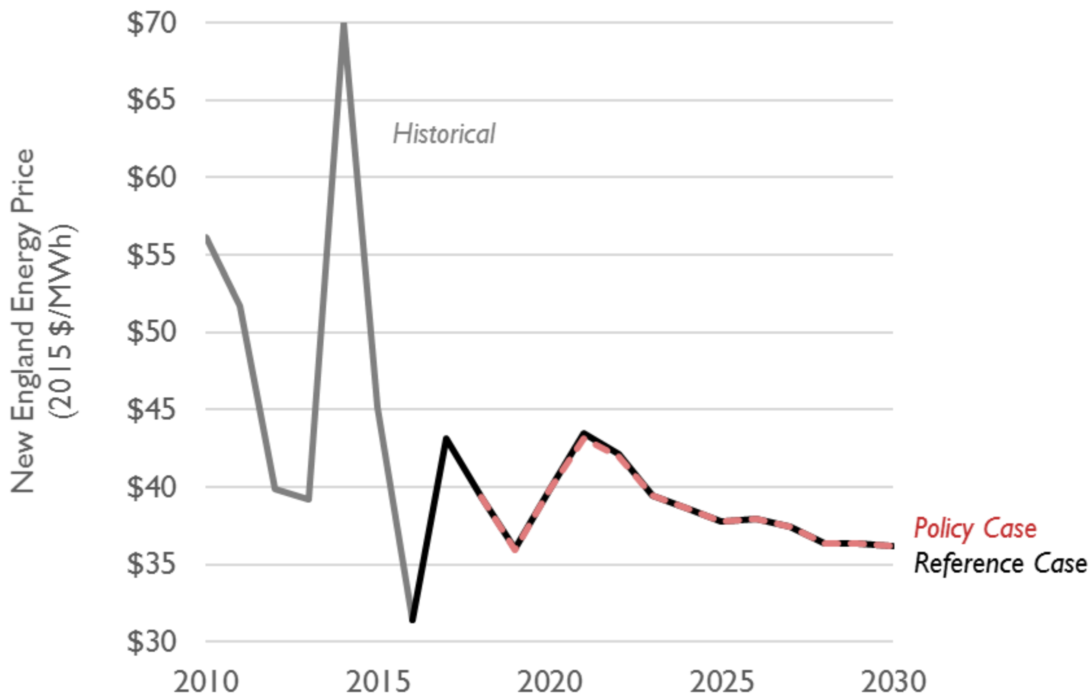
Between 2018 and 2022, the regulations decrease wholesale energy market prices between 0 and 0.7 percent. This effect can be linked to increased production from renewable generation. Renewable resources typically participate in wholesale energy markets as price takers (bidding zero dollars per MWh and displacing more expensive resources), or are deployed as a result of long-term bundled contracts, which establish combined energy and REC prices sufficient for the facility to operate. Both of these mechanisms drive down the wholesale energy costs throughout the region (see Figure 7).

Embedded in the wholesale energy market prices are the prices associated with CO_2 allowances (both those issued pursuant to 310 CMR 7.74, and those issued as part of the RGGI program).[11] Because the CO_2 emission limit is not binding in the Policy Case (or for that matter, in the Reference Case), the

[11] See Chapter 3 for more information on the impacts of changing the RGGI allowance price and Appendix B for more information on how the assumption for RGGI allowance price was determined.

effective CO_2 allowance price pursuant to 310 CMR 7.74 is $0 per metric ton in every year between 2018 and 2030.

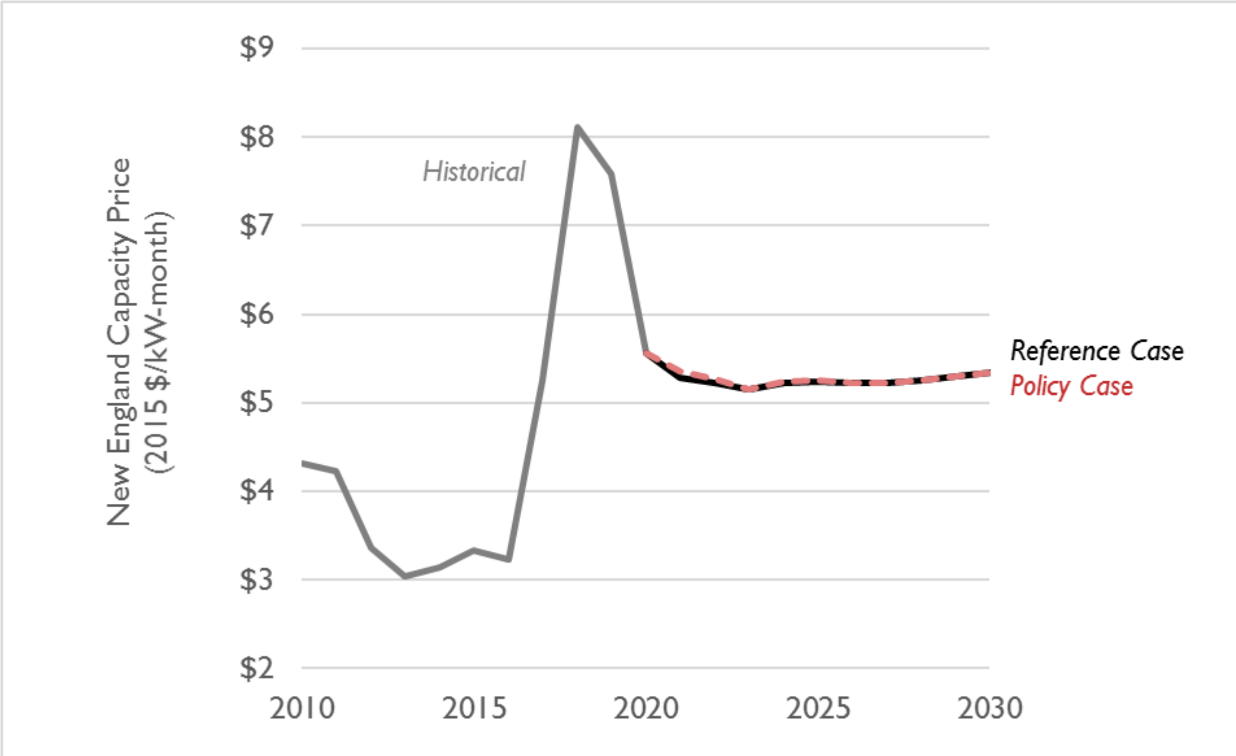
Figure 7. Wholesale energy market prices



The regulations cause capacity prices between 2018 and 2022 to vary between 0 and 1.4 percent, relative to the Reference Case (see Figure 8).[12] The observed changes in wholesale energy market prices and capacity market prices driven by the regulations are well within the bounds of the expected variability of more uncertain variables, such as upstream fuel prices or changes to capacity market rules. Since 2010, wholesale market prices have fluctuated as much as -35 to +78 percent year-on-year, while wholesale capacity prices have fluctuated as much as -27 to +63 percent year-on-year. In other words, the impact on prices caused by the regulations is smaller than what would be expected to be caused simply by normal variation in market conditions.

[12] In years where the EnCompass model estimates higher capacity prices, these are caused by corresponding decreases in wholesale energy prices. Note that capacity market prices are notoriously difficult to forecast for any one specific year because of changing market rules and supply conditions. Historically, rather than converging around an average price (as estimated in this analysis), capacity market prices have instead swung between very low and very high prices (constrained by administrative limits), as the available capacity has swung between over- and under-supply. Just as occurred in the most recent capacity auction, our modeling forecasts that future capacity prices are set by the fixed cost of the resource that would otherwise have retired without capacity market revenues.

Figure 8. Wholesale capacity market prices



Note: Capacity prices are established by ISO New England-administered Forward Capacity Auctions, which take place three years in advance of a commitment period. Thus, the capacity price is already known through May 2021. Capacity prices are issued on a "commitment period" basis, which spans June through May of each year; these prices have been converted into calendar-year prices for the purposes of this figure.

2.4 Renewable energy supply, demand, and REC price dynamics

All six New England states have active RPS policies, requiring varying (and typically increasing) percentages of obligated entity sales to be supplied by RPS-certified facilities. In Massachusetts, a Clean Energy Standard has been created as part of 310 CMR 7.75 to complement the RPS. Policy design, including changes over time, impacts the source and cost of renewable energy used for policy compliance. Since its inception in 2003, the Massachusetts RPS program has experienced periods of both shortage and surplus, leading to both high and low REC prices, respectively. Looking ahead, it is helpful to parse REC market dynamics over time by considering near-term (2017 through 2022) and long-term (2023 through 2030) expectations. Over the last several years, early renewable energy policies have resulted in substantial quantities of distributed generation—a significant portion of which is behind the meter and has the dual effect of creating REC supply and reducing REC demand. At the same time, regional load forecasts have transitioned from projected increases to projected decreases over the next 10 years. As a result, RPS markets are expected to be in surplus in the near-term; at least until the implementation of the Clean Energy Standard.

With the implementation of a Clean Energy Standard, the near-term surplus is expected to be reduced to near-equilibrium for the period spanning 2019 to 2022. During this time, REC prices will increase as a result of demand tension, but no incremental renewable energy supply beyond the already-committed pipeline will be required to meet the RPS and Clean Energy Standard policies—although some will nonetheless be built as a result of existing long-term contracting and net metering programs currently being implemented for regional distributed generation.

Renewable supply responding to this incremental Clean Energy Standard-driven demand will come from either renewable energy imports from adjacent control areas or existing biomass generators within ISO New England. Both sources of supply are price-responsive and will import or operate, respectively, only when the sum of energy and REC revenue is expected to exceed their short-run marginal cost. Put another way, this generation will elect not to generate and sell their full potential of RECs into the New England market in order not to further oversupply the market and further reduce REC prices. As renewable energy demand increases over time, a greater percentage of this available supply can be expected to import or operate, respectively. Table 3 summarizes incremental Class I generation from ISO New England and adjacent control areas in response to the Clean Energy Standard. Additional imports from large, Clean Energy Standard-eligible hydro facilities are also expected in 2023 and later years.

Table 3. Incremental renewable generation driven by the Clean Energy Standard, Policy Case (GWh)

	2016	2017	2018	2019	2020	2021	2022	2023 through 2030
Incremental eligible in-region generation	0	0	1,325	1,018	1,175	1,415	1,409	0
Incremental eligible imports	0	0	0	821	1,074	1,092	1,073	0

Near-term conditions notwithstanding, incremental legislation in Massachusetts and Connecticut has endowed the distribution utilities with long-term contracting authority. In Massachusetts, amendments to the Green Communities Act establish a pathway to competitively securing contracts for 1,600 MW of offshore wind and up to 9,450 GWh of hydroelectric (not eligible for the Class I RPS but eligible for the Clean Energy Standard) and Class I renewable energy through a competitive process. Fulfillment of this authority without corresponding increases in RPS demand targets would specify long-term market surpluses, and REC prices less than $5 per MWh once these resources are expected to come on-line in approximately 2023.

This analysis also includes banking in which obligated entities are allowed to over-comply with the RPS or Clean Energy Standard through state-specific annual compliance filings and then apply such excess compliance in either of the following two compliance years. To simplify, during periods in which current year REC prices are lower than expected future REC prices, obligated entities are assumed to bank RECs. During periods in which current year prices are higher than expected future REC prices, obligated entities are assumed not to bank excess compliance. In fact, entities with available bank balances would be expected to use them for RPS compliance in the current year, presumably replacing current-year REC expenditures with banked compliance that was accrued at lower cost. This analysis takes into account actual historic banking injections and withdrawals (as reported in state-by-state annual compliance filings), and estimates forward-looking banking behavior based on this experience and the expectations described above.

Based on these market factors and dynamics, we found that the price paid for RECs and CECs differs in some years between the Policy Case and the Reference Case. Based on eligibility criteria, the Clean Energy Standard will be fulfilled entirely by Class I RECs until eligible hydropower is delivered to New England from an adjacent control area over new transmission. We model such deliveries to commence in 2023. As a result, REC and CEC supply, demand and price will be the same through 2022. During this near-term period, the Clean Energy Standard creates incremental demand (above Massachusetts Class I demand) for Massachusetts Class I resources, and therefore places upward pressure on REC prices. Between 2019 and 2022, the regulations are expected to increase spot Massachusetts Class I REC prices by $15 to $19 per MWh in the Policy Case, relative to the Reference Case (see Figure 9 and Table 4). During this period, we expect REC and CEC prices to range between $27 and $29 per MWh in the Policy Case.[13]

This analysis finds that the REC and CEC market dynamics are distinctly different after 2022. Because Clean Energy Standard-qualifying hydropower represents a new category of supply that will create CECs but not RECs, beginning in 2023 the REC and CEC markets will have different supply, demand and price dynamics. The two markets will no longer function as one, and REC and CEC spot market dynamics and prices could separate. In the post-2022 CEC market, eligible hydropower, delivered over new transmission, is assumed to dramatically exceed total (as opposed to incremental) CEC demand in all cases. This means that the entire Clean Energy Standard obligation can, and is assumed to, be fulfilled by qualifying hydropower. This will cause a dramatic reduction in CEC prices, and may result in a CEC spot market with little or no activity or liquidity. As a result, by 2023, we find that the spot market price for CECs will fall to roughly $2 per MWh. This price reflects the expectation of considerable surplus, with CEC prices approximating transaction costs.

Class I RECs previously assumed to meet the incremental demand driven by the Clean Energy Standard demand will revert to the Class I RPS market. On top of this supply reversion, the post-2022 REC market will be impacted by incremental supply additions from legislated long-term contracting authority. These long-term contracted supplies are assumed to exceed incremental REC demand. If the full volume of long-term contracting authority is implemented without a corresponding increase in Class I RPS demand, then Class I REC prices are expected to remain suppressed from 2023 through 2030.

[13] We do not model REC/CEC prices as being different in 2018, as a result of the lag time between the regulations' promulgation and the time at which REC/CECs are purchased for compliance in 2018.

Figure 9. Spot market prices for Massachusetts Class I REC/CECs

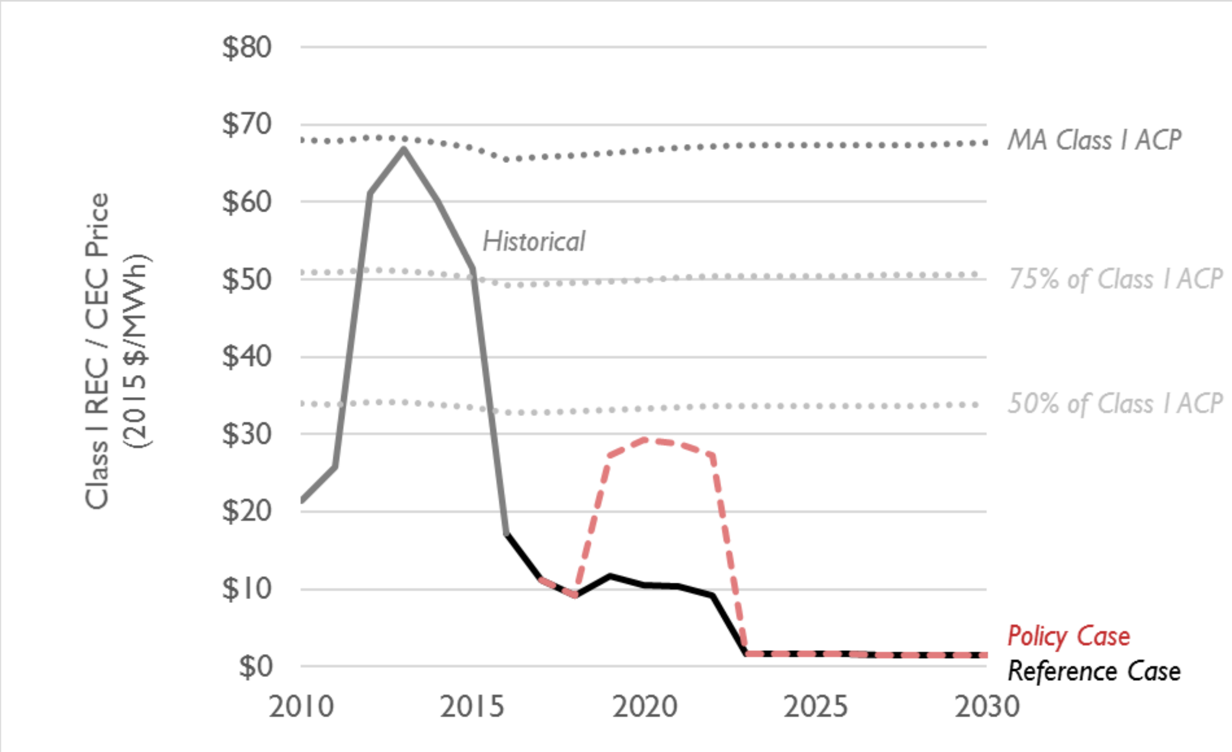


Table 4. Spot market prices for Massachusetts Class I REC/CECs (2015 $/MWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	…	2030
Reference Case	$17	$11	$9	$12	$11	$10	$9	$2	$2	$2	…	$1
Policy Case	-	-	$9	$27	$29	$29	$27	$2	$2	$2	…	$1

While short-term REC and CEC market prices will impact retail costs (whether they are high or low), it is important to remember that only a portion of RPS and Clean Energy Standard compliance will be fulfilled through short-term purchases. The remainder of RPS and Clean Energy Standard compliance will be fulfilled through a portfolio of long-term contracts with varying lengths, volumes, and prices. This analysis assumes that approximately 25 percent of Massachusetts RPS compliance is fulfilled through spot market purchases for compliance years 2018 to 2022, and then through long-term contracts for RECs beginning in 2023. As a result of recently enacted additional procurement authority, we anticipate the fraction of spot market purchases within the RPS to fall to 20 percent by 2030. With respect to the Clean Energy Standard, we assumed that all compliance will be fulfilled through long-term contracts for CECs in all cases. Consequently, ongoing surpluses in the CEC spot market are likely to reduce the price to a level reflecting transaction costs.

When evaluating expected REC/CEC pricing and the estimated cost of Clean Energy Standard compliance, we also considered the ACP rate. If the Clean Energy Standard ACP is set at any level greater than 50 percent of the Massachusetts Class I ACP, then we would not expect it to become binding and influence Clean Energy Standard compliance costs in any year in any case. If the Clean Energy Standard

ACP is set at 50 percent of the Massachusetts Class I ACP, we concluded that it would still not be a binding price constraint on Clean Energy Standard compliance in the Policy Case.

2.5 Retail Bill Impacts

Taken together, impacts on wholesale energy market prices (inclusive of CO_2 allowance prices), wholesale capacity market prices, and spot prices paid for RECs and CECs allow us to estimate retail bill impacts. Table 5 shows relative monthly bill impacts for four different types of electricity customers in Massachusetts.[14] These relative monthly bill impacts (measured in 2015 dollars per month) represent the incremental cost of paying for the regulations in any given year. For residential customers, these costs range from 14 cents to $1.22 per month between 2018 and 2022.

For comparison purposes, Table 5 also shows a recent historical bill for typical customers within each of these customer classes. In addition, this table provides a percentage impact, which describes the degree to which the Reference Case / Policy Case bill impact represents an increase over the monthly cost of electricity paid for by Massachusetts ratepayers today. For residential customers, these percent impacts range from 0.1 percent to 0.9 percent. While these percent impacts are higher for some customer classes in some years, the percent impact is estimated to not exceed 1.5 percent in any year for any typical customer.[15, 16]

[14] More information on the bill impact methodology and the data sources used to determine historical bills and customer classes can be found in Appendix A.

[15] Note that these relative bill impacts do not include any impacts of future changes that occur in both the Reference Case and Policy Case. If future changes to the electric system cause monthly electric bills to increase in the Reference Case (i.e., absent any new regulations), any bill impact increase will be diminished, in percentage terms. Conversely, if future changes to the electric system decrease monthly electric bills in the Reference Case, higher relative bill impacts in the Policy Case will translate into a larger percentage increase.

[16] Table 5 shows some bill impacts (on the order of less than 0.1 percent) in years after 2022 in some commercial and industrial customer classes. These variations in bill impacts are due to differences in wholesale market prices, which in turn are caused by differences in unit dispatch in years prior to 2023.

Table 5. Relative bill impacts for residential and commercial and industrial (C&I) customer classes (2015 $ per month)

		2016	…	2018	2019	2020	2021	2022	2023	2024	2025	…	2030
Residential	Recent historical	$133											
	Policy		…	$0.14	$0.93	$1.19	$1.22	$1.20	$0.00	$0.01	$0.02	…	$0.00
			…	0.1%	0.7%	0.9%	0.9%	0.9%	0.0%	0.0%	0.0%	…	0.0%
Small C&I	Recent historical	$1,076											
	Policy		…	$1.19	$7.72	$9.93	$10.20	$10.00	$0.02	$0.10	$0.16	…	$0.00
			…	0.1%	0.7%	0.9%	0.9%	0.9%	0.0%	0.0%	0.0%	…	0.0%
Med. C&I	Recent historical	$6,587											
	Policy		…	$11	$69	$89	$92	$90	$0	$1	$1	…	$0
			…	0.2%	1.1%	1.4%	1.4%	1.4%	0.0%	0.0%	0.0%	…	0.0%
Large C&I	Recent historical	$71,949											
	Policy		…	$125	$810	$1,043	$1,071	$1,050	$2	$10	$16	…	$0
			…	0.2%	1.1%	1.4%	1.5%	1.5%	0.0%	0.0%	0.0%	…	0.0%

3. SENSITIVITY FINDINGS

In addition to the two main scenarios, the Reference Case and the Policy Case, we examined a set of other scenarios to explore how altering input assumptions could change study results. The following section contains selected findings from our analysis of these study sensitivities.

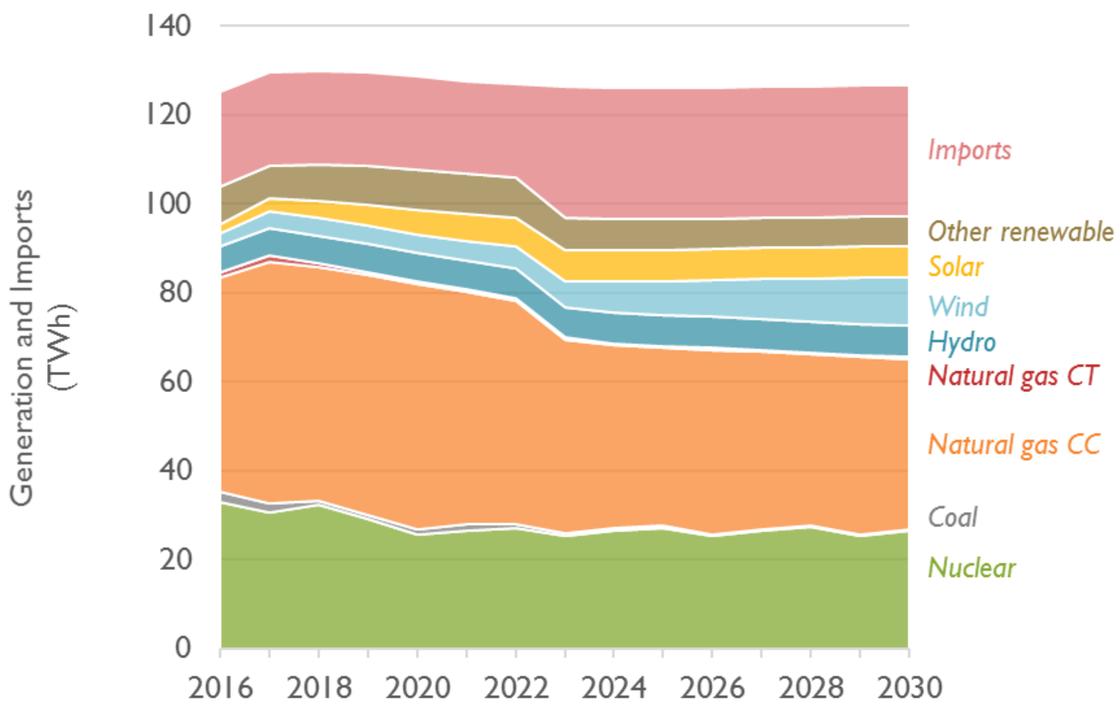
3.1 Alternative sales forecast

We examined the impact of a Policy Case with an alternative sales trajectory. In this alternative sales forecast, we relied on the most recent sales forecast developed by ISO New England instead of the Synapse-developed forecast used in the main scenarios.[17] In this alternative sensitivity, near-term demand for electricity from 2018 through 2022 in New England and Massachusetts is 5 percent higher than in the main scenarios, although over the long term (through 2030) electricity demand in both trajectories is comparable to 2016 demand.

Under this alternative sales forecast, the Policy Case shows 10 percent of the increase in near-term electricity demand met by increased generation from renewable sources. The remaining 90 percent is met by an increase in fossil generation—primarily from natural gas combined-cycle generators (see Figure 10). However, by 2030, the total output from fossil generators declines to 40 percent of in-region generation, in line with the level of fossil generation observed in the main Policy Case.

[17] More information on the methodology and assumptions used to develop the two sales forecasts can be found in Appendix B.

Figure 10. New England-wide electricity generation and net imports in the Policy Case with an alternative sales forecast



This change in fossil dispatch leads to greater absolute CO_2 emissions in the alternative sales sensitivities than were observed in the main Reference Case and main Policy Case. Thus, it causes the implementation of the regulations to have a greater relative impact on CO_2 emissions. Specifically, under the alternative sales forecast, the CO_2 emissions limit under 310 CMR 7.74 is binding in 2018, but not in any other year (see Figure 11). When this effect is combined with the impact of increased renewable generation driven by the Clean Energy Standard, we observe overall lower CO_2 emissions in Massachusetts in 2018 through 2022, relative to the Reference Case. Although these emission reductions are offset to a degree by a slight increase in CO_2 emissions in the other New England states in 2018, in all other years the regulations drive lower emissions in these states as well (see Figure 12). When taking all six New England states together, we observe lower aggregate CO_2 emissions in all years in the Policy Case, relative to the Reference Case.

Figure 11. CO_2 emissions from Massachusetts electric power generators under the alternative sales forecast

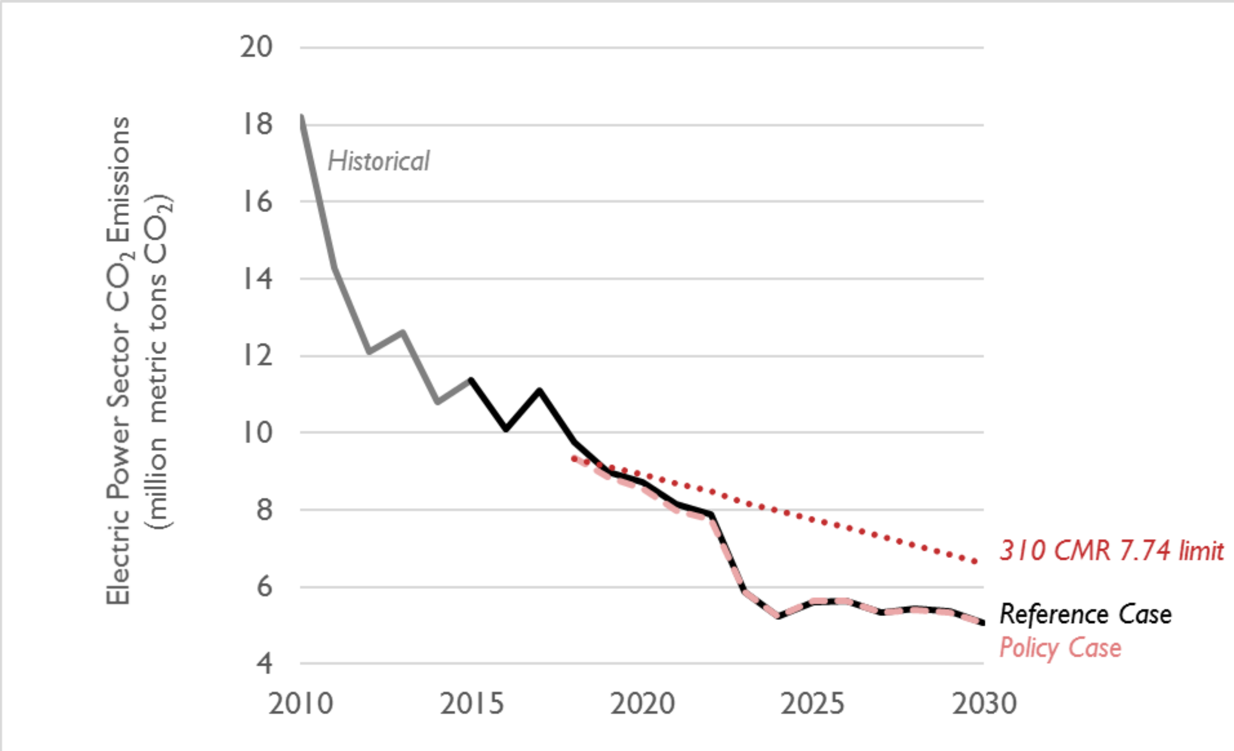
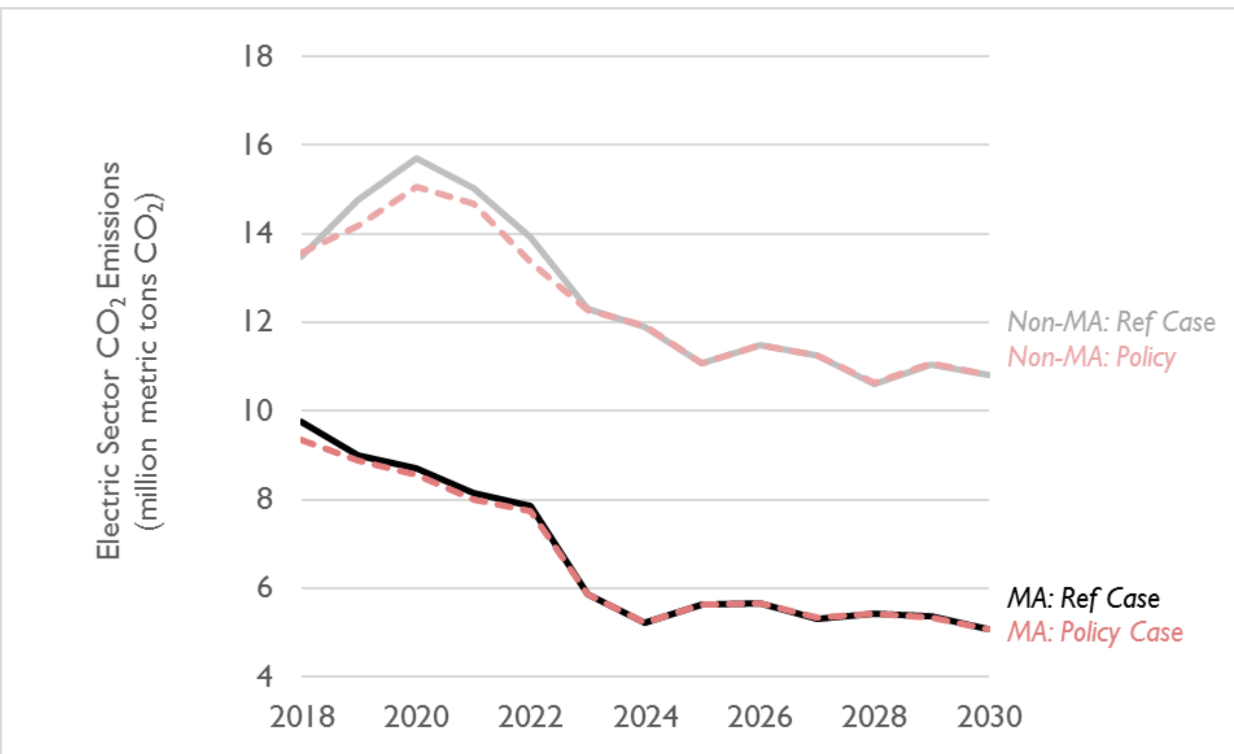
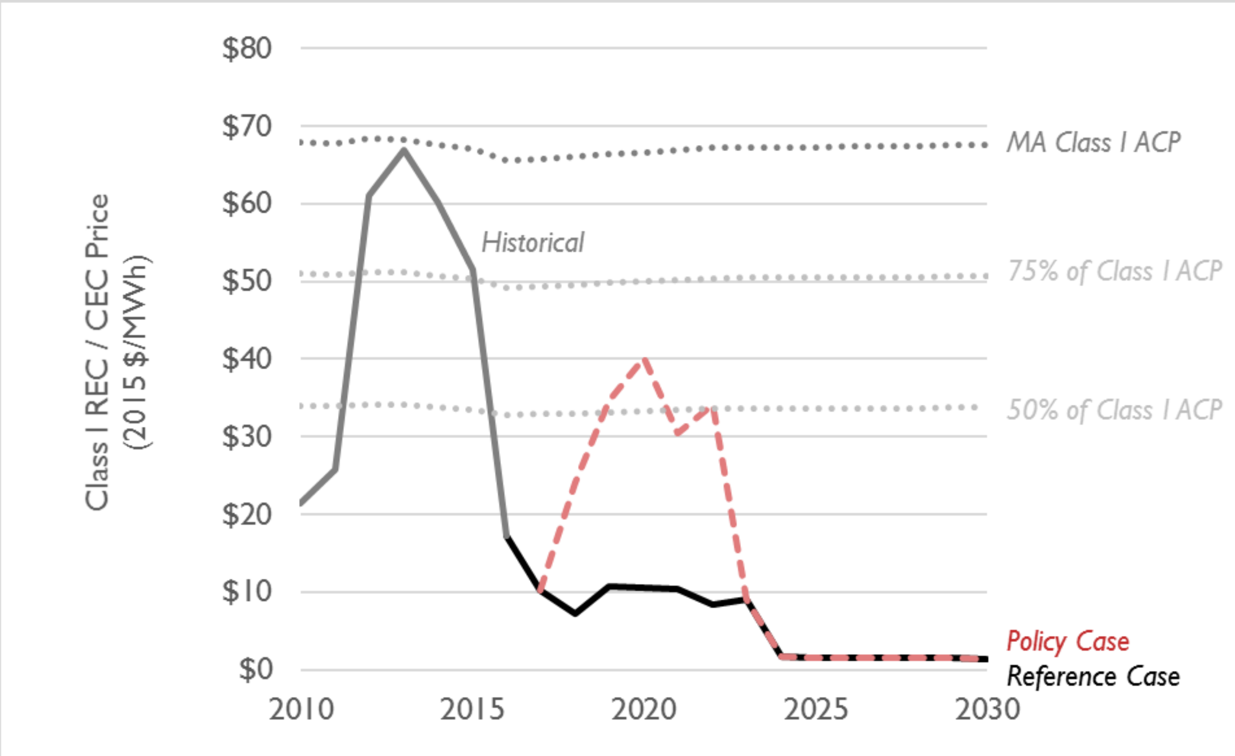


Figure 12. CO_2 emissions from Massachusetts and non-Massachusetts electric power generators under the alternative sales forecast



As in the main scenarios, relative impacts to wholesale energy market prices and wholesale capacity market prices between the Reference Case with an alternative sales forecast and the Policy Case with an alternative sales forecast are small. Between 2018 and 2022, wholesale energy market price impacts range from -0.4 to 1.7 percent, and wholesale capacity market price impacts range from 0 to 1.4 percent. The higher level of electricity sales drives a greater absolute demand for RECs and CECs between 2018 and 2022, resulting in a higher spot price for RECs/CECs (as high as $40 per MWh in 2020). However, this price also falls in 2023 once new, imported hydroelectric resources are fully operational (see Figure 13 and Table 6).[18]

Figure 13. Spot market prices for Massachusetts Class I REC/CECs in the alternative sales forecast



[18] Note that in three years (2019, 2020, and 2022), the spot price for RECs and CECs reaches 52 to 60 percent of the Massachusetts Class I ACP price. In modeling this sensitivity, we assumed that the price of CECs could reach up to 100 percent of the Class I ACP price. If a Clean Energy Standard ACP limited to 50 percent of the Class I ACP price is implemented, then ACP payments will replace CEC purchases for a portion of the obligation in these three years. This will cause a reduction in bill impacts for the Policy Case in the alternative sales forecast compared to the values shown in this report.

Table 6. Spot market prices for Massachusetts Class I REC/CECs in the alternative sales forecast (2015 $/MWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	…	2030
Reference Case	$17	$10	$7	$11	$11	$10	$8	$9	$2	$2	…	$1
Policy Case	-	-	$24	$35	$40	$30	$34	$9	$2	$2	…	$1

In aggregate, these price changes result in slightly higher bill impacts relative to the main scenarios (see Table 7). For residential customers, bill impacts range from $0.98 to $1.72 per month between 2018 and 2022, or 1.0 to 1.3 percent of a typical 2016 monthly electricity bill. For some commercial and industrial customer classes, bill impacts are higher in some years, but do not exceed 2.1 percent in any year. As in the main scenarios, no bill impacts are observed in years after 2022.[19]

Table 7. Relative bill impacts for residential and commercial and industrial (C&I) customer classes under the alternative sales forecast (2015 $ per month)

		2016	…	2018	2019	2020	2021	2022	2023	2024	2025	…	2030
Residential	Recent Historical	$133											
	Policy		…	$0.98	$1.33	$1.72	$1.39	$1.66	$0.00	$0.02	$0.00	…	$0.00
			…	0.7%	1.0%	1.3%	1.0%	1.2%	0.0%	0.0%	0.0%	…	0.0%
Small C&I	Recent Historical	$1,076											
	Policy		…	$8.13	$11.11	$14.35	$11.55	$13.85	$0.01	$0.13	$0.04	…	$0.02
			…	0.8%	1.0%	1.3%	1.1%	1.3%	0.0%	0.0%	0.0%	…	0.0%
Med. C&I	Recent Historical	$6,587											
	Policy		…	$73	$100	$129	$104	$125	$0	$1	$0	…	$0
			…	1.1%	1.5%	2.0%	1.6%	1.9%	0.0%	0.0%	0.0%	…	0.0%
Large C&I	Recent Historical	$71,949											
	Policy		…	$853	$1,167	$1,506	$1,213	$1,454	$1	$14	$4	…	-$1
			…	1.2%	1.6%	2.1%	1.7%	2.0%	0.00%	0.0%	0.0%	…	0.0%

[19] As in Table 5, Table 7 shows some bill impacts (on the order of less than 0.1 percent) in years after 2022 in some commercial and industrial customer classes. These variations in bill impacts are due to differences in wholesale market prices, which in turn are caused by differences in unit dispatch in years prior to 2023.

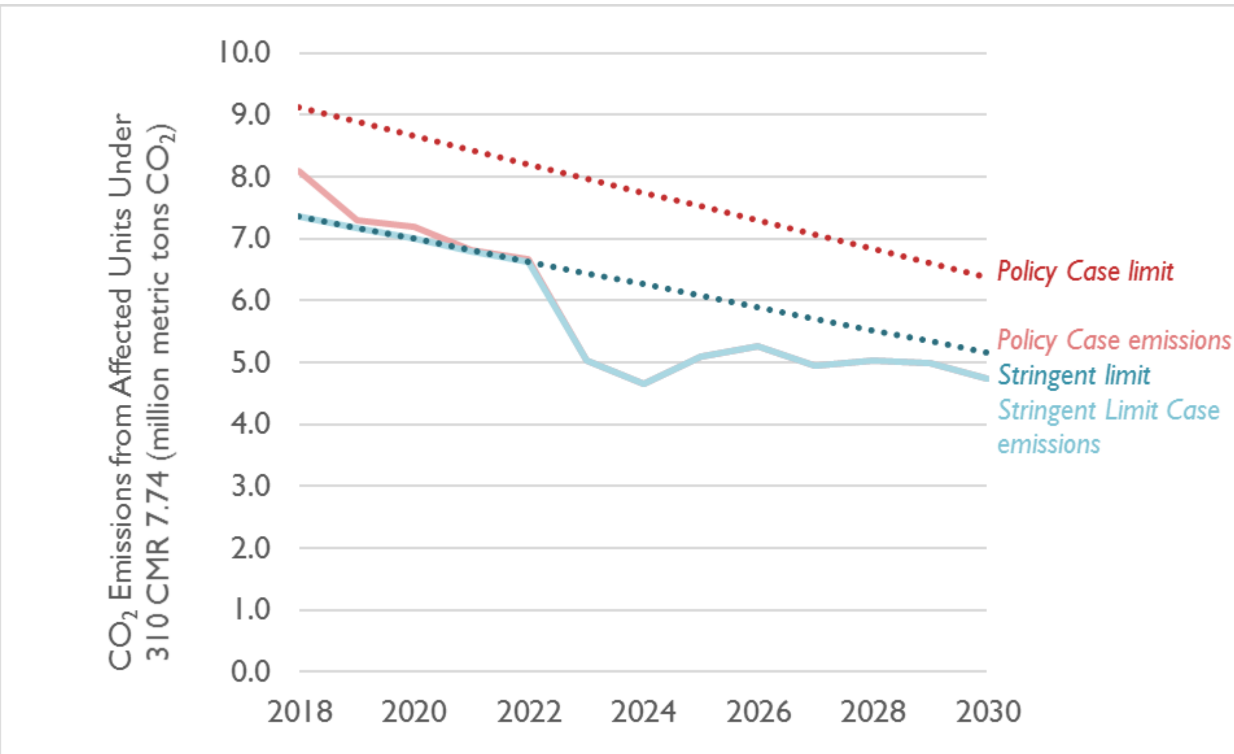
3.2 Other sensitivities

Stringent Limit Case

We examined a variation of the Policy Case in which a different Massachusetts-specific CO_2 limit is implemented in the future. In this other scenario, the "Stringent Limit Case," the CO_2 emissions limit starts at 7.4 million metric tons in 2018, or 19 percent lower than the limit analyzed in the Policy Case. It then declines by 2.5 percent of the 2018 value in every subsequent year.

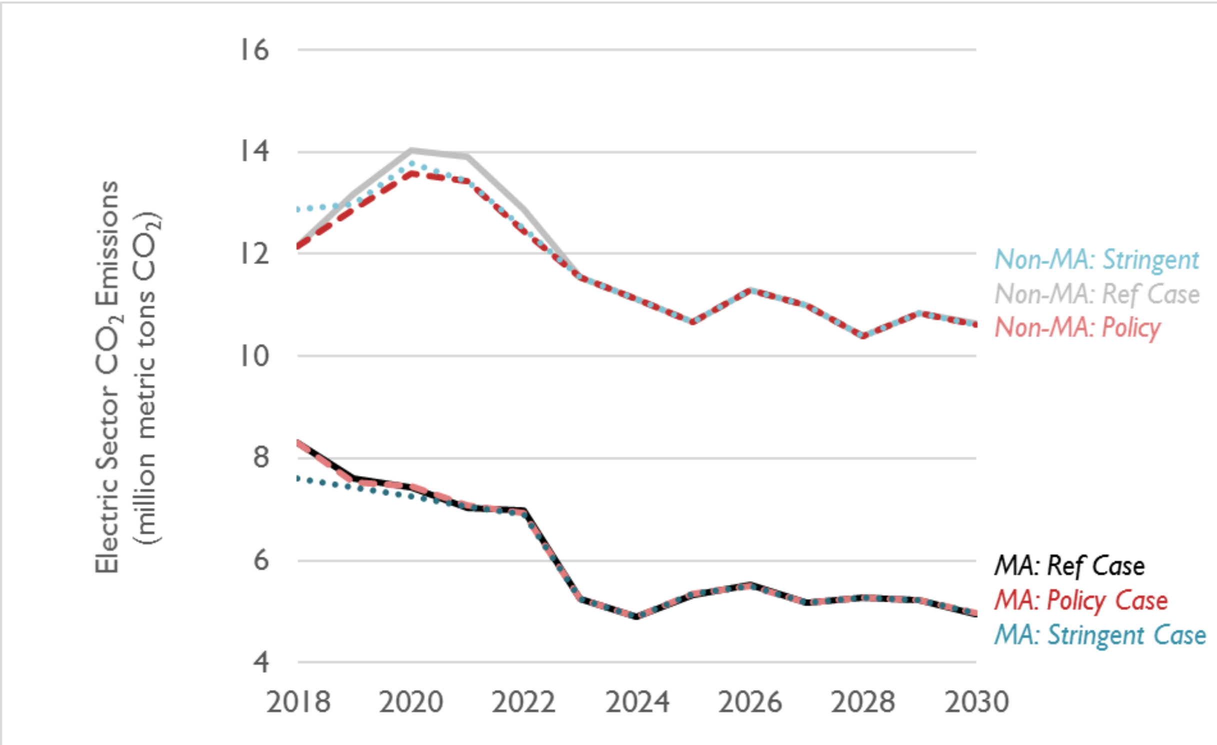
Unlike in the Policy Case, we found the CO_2 emissions limit to be binding in some years in the Stringent Limit Case (see Figure 14). In this alternative scenario, the CO_2 emissions limit is binding in every year from 2018 to 2020 and 2022.

Figure 14. CO_2 emissions from affected Massachusetts electric power generators in the Policy Case and Stringent Limit Case



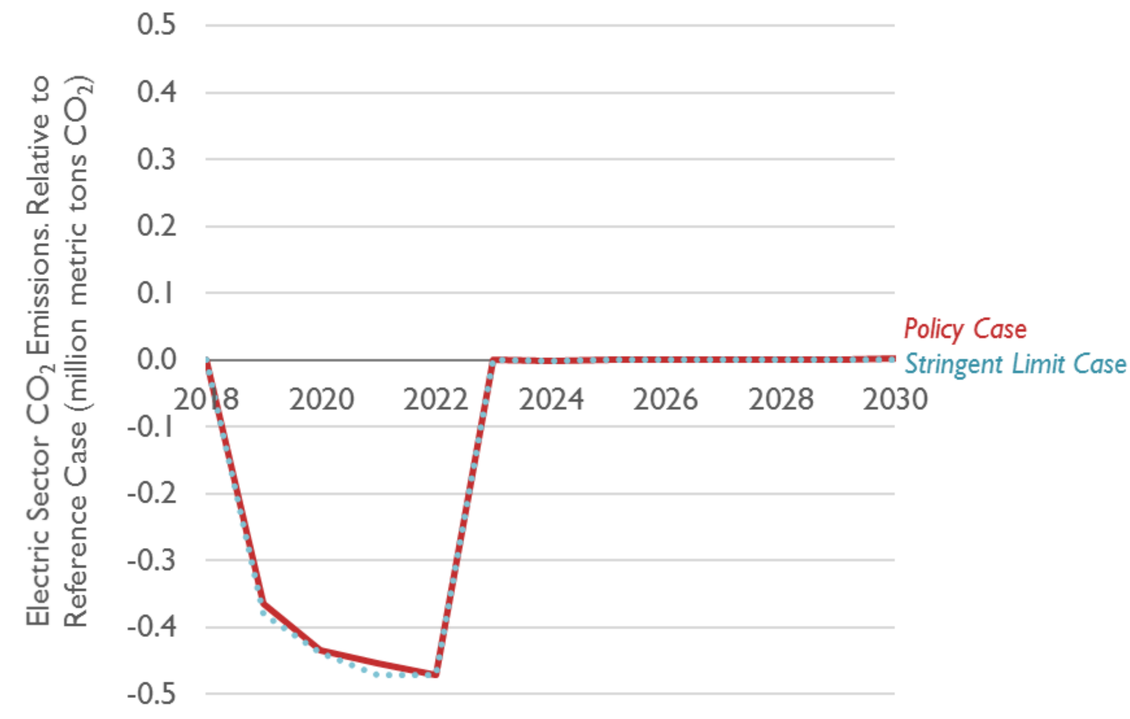
One result of this binding limit on Massachusetts CO_2 emissions in the Stringent Limit Case is a shift in generation from fossil generators located in Massachusetts to fossil generators located in other New England states. In the Stringent Limit Case, CO_2 emissions in Massachusetts over the entire 2018 to 2030 study period decrease by 1.4 percent relative to the Policy Case, but they increase in the other New England states by 0.7 percent. In aggregate, for all of New England, the Stringent Limit Case results in emissions that are 0.8 percent lower than that observed in the Reference Case, and less than 0.1 percent lower than observed in the Policy Case (see Figure 16).[20]

Figure 15. CO_2 emissions from Massachusetts and New England electric power generators in the Reference Case, Policy Case, and Stringent Limit Case



[20] We observed similar results for a Stringent Limit Case under an alternative sales forecast.

Figure 16. Difference between New England CO_2 emissions in the Reference Case and Policy Case, and the Reference Case and the Stringent Limit Case



High natural gas price forecast

In a third sensitivity, we examined the impacts on emissions and system dispatch under a high natural gas price forecast. Regardless of natural gas price, electric sales forecast, or regulations, the majority of dispatchable emitting generation in New England in future years is composed of natural gas-fired combined cycle generators.[21] As a result, regardless of the constraints imposed on the electric system, these natural gas-fired combined cycle generators are the resources likely to respond with increased or decreased electric generation, rather than other resources (such as the remaining coal-fired generators).

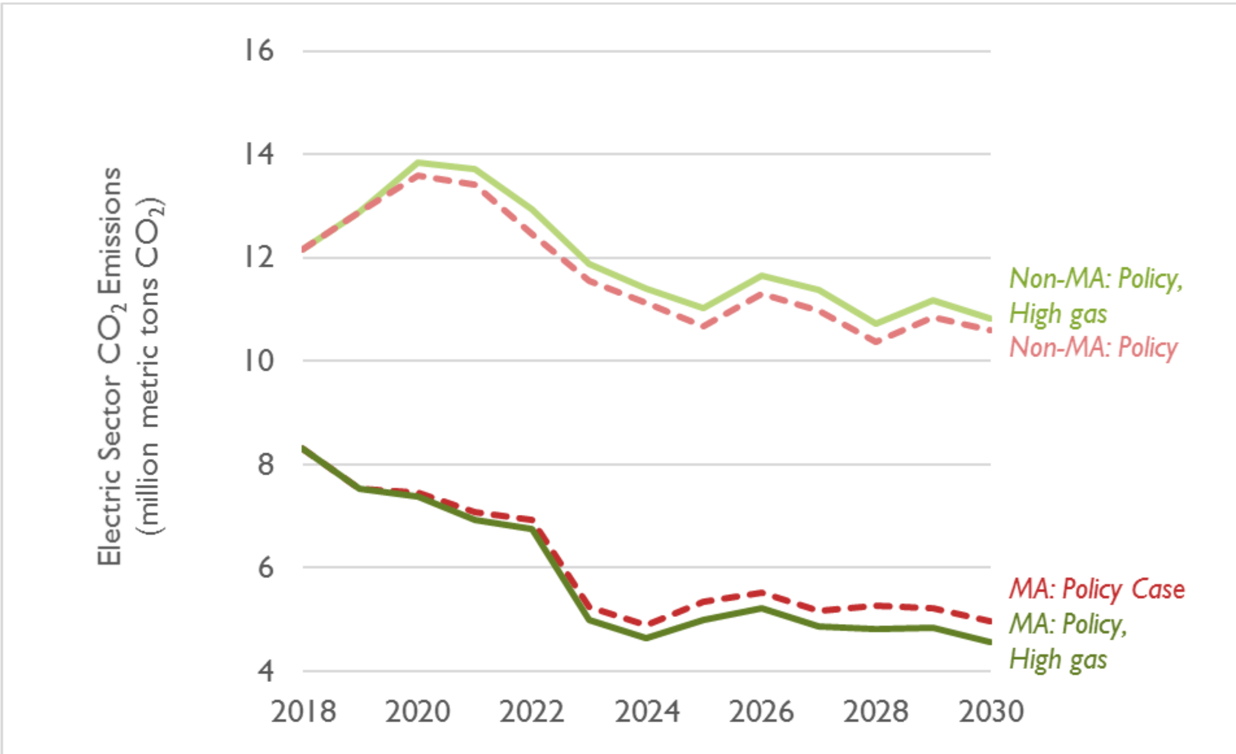
As a result, even with a natural gas price 50 percent higher than assumed in the main scenarios, electric-sector CO_2 emissions do not substantially change in the Policy Case (see Figure 17). In many years, higher natural gas prices drive down generation from natural gas generators in Massachusetts and other states, while driving up generation from coal plants in New Hampshire.

In this scenario, Massachusetts' electric sector emissions are even lower than in the main Policy Case, once again causing the CO_2 cap to not be binding. It is likely that this same effect would be observed in a

[21] This includes power plants which may occasionally consume petroleum rather than natural gas.

Reference Case with a high natural gas price, which would imply wholesale price impacts and retail bill impacts differentials similar to those observed in the main Policy Case and main Reference Case.

Figure 17. CO_2 emissions from Massachusetts and New England electric power generators in the main Policy Case and Policy Case under a high natural gas price



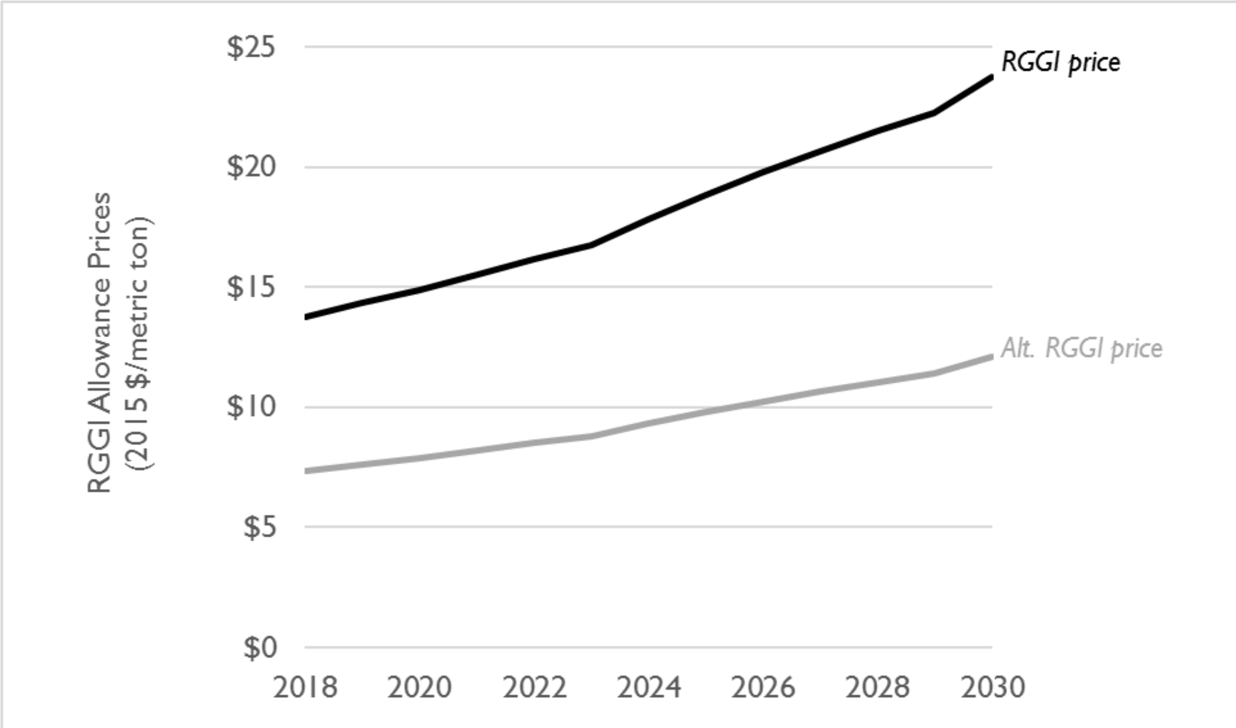
Alternative RGGI price forecast

In a fourth sensitivity, we analyzed the effect of a different RGGI allowance price. All six New England states are part of RGGI and generators in those states must purchase emission allowances from a continually decreasing pool.[22]

In the main scenarios, we assumed the price of allowances under RGGI would follow a price trajectory based on a blending of April 2016 modeled prices from the 2016 RGGI Program Review (see "RGGI Price" in Figure 18). Under this trajectory, RGGI allowance prices increase from about $14 in 2018 to $24 in 2030. In the RGGI price sensitivity, we developed an alternative allowance price trajectory based on modeled prices released in June 2017 under the 2016 RGGI Program Review. These prices range from $7 in 2018 to $12 in 2030, or about half the value of the main scenario RGGI price in any given year.

[22] More information on the assumptions used for RGGI are available in Appendix B.

Figure 18. RGGI CO_2 allowance prices assumed in the main scenarios ("RGGI price") and alternative sensitivity ("Alt. RGGI price")



As with changes to the natural gas price forecast, changes to the RGGI allowance price forecast affect most emitting generators throughout New England. Because the majority of emitting generators in New England are natural gas-fired combined cycle units (on a generation basis), and because many of these generators have similar ton-per-MWh emissions rates, the main impact of a decreased RGGI price is to lower the wholesale energy market price. However, decreasing the RGGI price does not lead to substantially different emissions.

In the alternative RGGI allowance price sensitivity, Massachusetts' electric sector emissions are similar to those in the main Policy Case, and the Massachusetts-specific CO_2 limit is not binding. Given the lack of a binding limit, it is also likely that a Reference Case with a different RGGI allowance price (which was not modeled) would be similar to the main Reference Case. As a result, it is likely that relative wholesale price impacts and retail bill impacts under a different RGGI allowance price would be similar to the differentials observed between the main Policy Case and main Reference Case.

APPENDIX A. MODELING METHODOLOGY

This analysis used two models in conjunction: EnCompass (Version 2.4), a state-of-the-art electric power capacity expansion and production cost model produced by Anchor Power Solutions, and the Renewable Energy Market Outlook (REMO) model, a proprietary model developed by Sustainable Energy Advantage for assessing renewable builds and REC prices.

The Renewable Energy Market Outlook Model

For this analysis, Sustainable Energy Advantage has relied on New England REMO, a set of models developed by Sustainable Energy Advantage that estimate forecasts of scenario-specific renewable energy build-outs, as well as REC and CEC price forecasts. Within REMO, Sustainable Energy Advantage has defined forecasts for both near-term and long-term project buildout and REC/CEC 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. The near-term REC/CEC price forecasts are a function of existing, RPS-certified renewable energy supplies, near-term renewable builds, regional RPS demand, Massachusetts Clean Energy Standard demand, ACP levels in each market, and other dynamic factors. Such factors include banking, borrowing, imports, and discretional curtailment of renewable energy. The long-term REC/CEC price forecasts are based on a supply curve analysis taking into account 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. The long-term REC price forecast is 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.

The EnCompass Model

Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that allows for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis
- Long-term integrated resource planning, including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

EnCompass provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions described in Appendix B and Appendix C. Synapse populated the model with a custom New England dataset developed by Anchor Power Solutions and based on the 2015 Regional System Plan, which has been validated against actual unit-specific 2015 dispatch data.[23] Synapse used EnCompass to optimize the generation mix in New England and to estimate the costs of a changing energy system over time. Because this study focuses on annual generation, costs, and emissions, the model was run in "partial" optimization mode with typical peak/off-peak day temporal resolution. These parameters enabled faster processing time at the expense of some detail at the unit operation level.

More information on EnCompass is available at www.anchor-power.com.

Bill Impacts

For this analysis, Synapse developed a custom-built, Excel spreadsheet-based model that estimates bill impacts for Massachusetts ratepayers across a variety of customer classes. This spreadsheet model integrates wholesale market price and expenditure data from EnCompass (including changes to wholesale energy costs, CO_2 allowance costs, wholesale capacity costs, and transmission costs) and spot market REC/CEC price and expenditure data from REMO to estimate the annual, relative change in monthly retail bills between two scenarios.

To define customer classes, we relied on a March 2016 filing by National Grid to the Massachusetts Department of Public Utilities.[24] This document provides estimated monthly usage (measured in kWh) and monthly bills (measured in dollars per month) for Massachusetts customers under a residential rate class and commercial and industrial rate classes.

Our analysis focused on the difference in costs between scenarios, meaning that while we accounted for variables that change between scenarios (such as energy prices, capacity prices, and REC prices), we did not account for cost impacts that are assumed to be the same in all scenarios (for example, any transmission costs associated with incremental hydroelectric imports from Canada).[25] Because we have not accounted for the full, incremental cost of all changes to the electric system (and have instead focused on the differential cost between scenarios), scenario-to-scenario bill impacts cannot be directly

[23] ISO New England. "2015 Regional System Plan." Available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[24] National Grid Energy Efficiency Reconciliation Factors Filing D.P.U. 16-26, March 1, 2016, Attachment 3 Mass. Electric Typical Bills.

[25] Note that we exclude all policy-based renewable supply (e.g., offshore wind required under 83C), which is assumed to have the same prices and quantities in each scenario. In instances in which the utility or energy distribution company as provider of last resort (POLR) banks RECs at a market price and market prices experience a subsequent prolonged crash, there is a material risk that the POLR will either sell additional RECs at a material loss or be unable to sell them at all; if the POLR is allowed to pass such costs through to distribution ratepayers, the bill impacts shown here would be greater. This impact has not been modeled as part of this analysis.

added to historical bills (as provided in the National Grid 16-26 docket) to calculate total future bills. Instead, we have provided historical bills to provide context for the magnitude of the scenario-to-scenario differential bill impacts.

Temporal Scope

The time period of this analysis is 2016 to 2030. REMO and EnCompass modeling was performed for each year, at an hourly resolution for typical peak and off-peak days in each month. Historical data for 2010 through 2015 were included in post-processing to provide comparison for data points in future years.

Geographic Scope

We used EnCompass to model all six New England states with unit-specific resolution, with the ISO New England system modeled as 13 separate zones within the ISO New England balancing area. Trade within New England was constrained by the region's major transmission paths. We modeled transfers between New England and its neighbors, including New York, Québec, and New Brunswick, as set import/export patterns based on actual 2015 hourly flows.

APPENDIX B. SCENARIOS AND SCENARIO ASSUMPTIONS

This analysis quantifies incremental impacts of the regulations by estimating the potential change in wholesale market prices (including energy and capacity prices), REC and CEC prices, CO_2 allowance prices, capacity, generation, and electric-sector CO_2 emissions for each modeled scenario compared to a reference or business-as-usual case. The main scenarios analyzed include:

- **Reference Case:** This scenario assesses a business-as-usual future in which no changes are made to existing laws and regulations in Massachusetts or any other New England state. Specifically, this scenario models a future in which the policies regarding unit-specific emissions caps and the under 310 CMR 7.74 and 7.75 are not implemented.

- **Policy Case with new regulations:** This scenario is the same as the Reference Case with two exceptions: (1) it assumes that the CO_2 emission caps on electric generators under 310 CMR 7.74 is in effect, and (2) it assumes that the Clean Energy Standard under 310 CMR 7.75 is in effect.

In addition to the two main scenarios, we assessed the impact of changing several of the key assumptions on costs and emissions. We also assessed the sensitivity of costs and emissions to different policy scenarios, including an alternative sales forecast, a more stringent CO_2 emissions limit under 310 CMR 7.74, a high natural gas price forecast, and an alternative RGGI CO_2 allowance price forecast.

Electricity sales and energy efficiency

For this analysis, we developed a main projection of electricity demand for use in the main Reference Case and main Policy Case scenarios. In addition, we developed a second, alternative projection of electricity demand for use in the alternative sales sensitivities.[26] Both projections rely on three main components:

1. An econometric forecast of future electricity demand
2. The impact on electricity demand from energy efficiency measures
3. Additional electricity demand resulting from increased electric vehicle deployment or end-use electrification

In addition, electricity sales vary due to incremental levels of behind-the-meter or distributed generation. See the following sections for detail on the assumptions used in this analysis for demand-side renewable resources.

[26] Note that the electricity sales projections developed in this analysis are not meant to be definitive statements of demand in future years. Electricity demand may fluctuate based on weather, economic conditions, technological advances, or other factors. These projections represent a best-guess estimate of the most-likely future levels of electricity demand.

Econometric electricity demand

In the Synapse electric demand forecast, we used the annual cumulative average growth rate from ISO New England's CELT 2017 econometric sales forecast for electricity sales and peak loads—without any energy efficiency or behind-the-meter solar— to build a baseline electricity forecast for all six New England states through 2026. Because the CELT 2017 forecast only goes through 2026, we then relied on the electricity sales forecast modeled for the New England region in AEO 2017 for the years 2027 through 2030.[27] In the alternative sales projection, we used the actual sales forecast numbers from CELT 2017 in all years through 2026, and used the 2017 to 2026 cumulative average growth rate to estimate sales in 2027 through 2030.

Energy efficiency

In the main scenarios, we relied on available information from each New England state's program administrator for estimates of energy efficiency. This included data provided by utilities in Massachusetts' joint three-year electricity efficiency program for 2016–2018, Connecticut's 2014 Integrated Resource Plan, Rhode Island's proposed energy efficiency savings targets for 2015–2017, and similar documentation in other states. In most cases, these estimates are only provided for the next few years. For all years after the last year in which energy efficiency forecasts are published, we assumed the same MWh quantity of energy efficiency is installed. We assumed that all annual portfolios follow the measure expiration schedule defined by a 2015 LBNL technical report memo *Energy Savings, Lifetimes and Persistence: Practices Issues, and Data*.[28] As a result, over time, older energy efficiency measures decay and drop out of the sales forecast, but are replaced in part by new measures. By the late 2020s, we modeled states entering a pattern of one-for-one replacement for old measures with new measures.

This methodology results in annual average energy efficiency savings of 2.0 percent per year for New England as a whole, and net cumulative energy efficiency savings of 17 percent in 2030 (relative to a baseline year of 2010) for New England as a whole. We note that leading states like Massachusetts are planning to achieve savings levels on the order of 3 percent over the next few years, while other states estimate lower levels of energy efficiency.

In the alternative sales forecast, we relied on the levels of energy efficiency calculated by ISO New England in its CELT 2017 projection.[29]

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[27] For projecting electricity sales, we used the AEO 2017 Reference case with No Clean Power Plan case. Like previous versions of this projection, the AEO 2017 Reference case with No Clean Power Plan case does not assume any future state-specific energy efficiency measures, outside of those expected under federal regulations. Meanwhile, the AEO 2017 Reference case assumes the Clean Power Plan is in effect, and that states use energy efficiency for compliance. We did not use this forecast, since it might have led to double-counting of energy efficiency savings.

[28] This is the same measure expiration schedule assumed by EPA in the development of the Clean Power Plan. More information available at https://www.epa.gov/sites/production/files/2015-11/df-cpp-demand-side-ee-at3.xlsx.

[29] The ISO New England CELT forecast instead relies on the levels of energy efficiency that have obligations under the New England capacity market, which undercounts the amount of energy efficiency planned by program administrators. A

Vehicle electrification

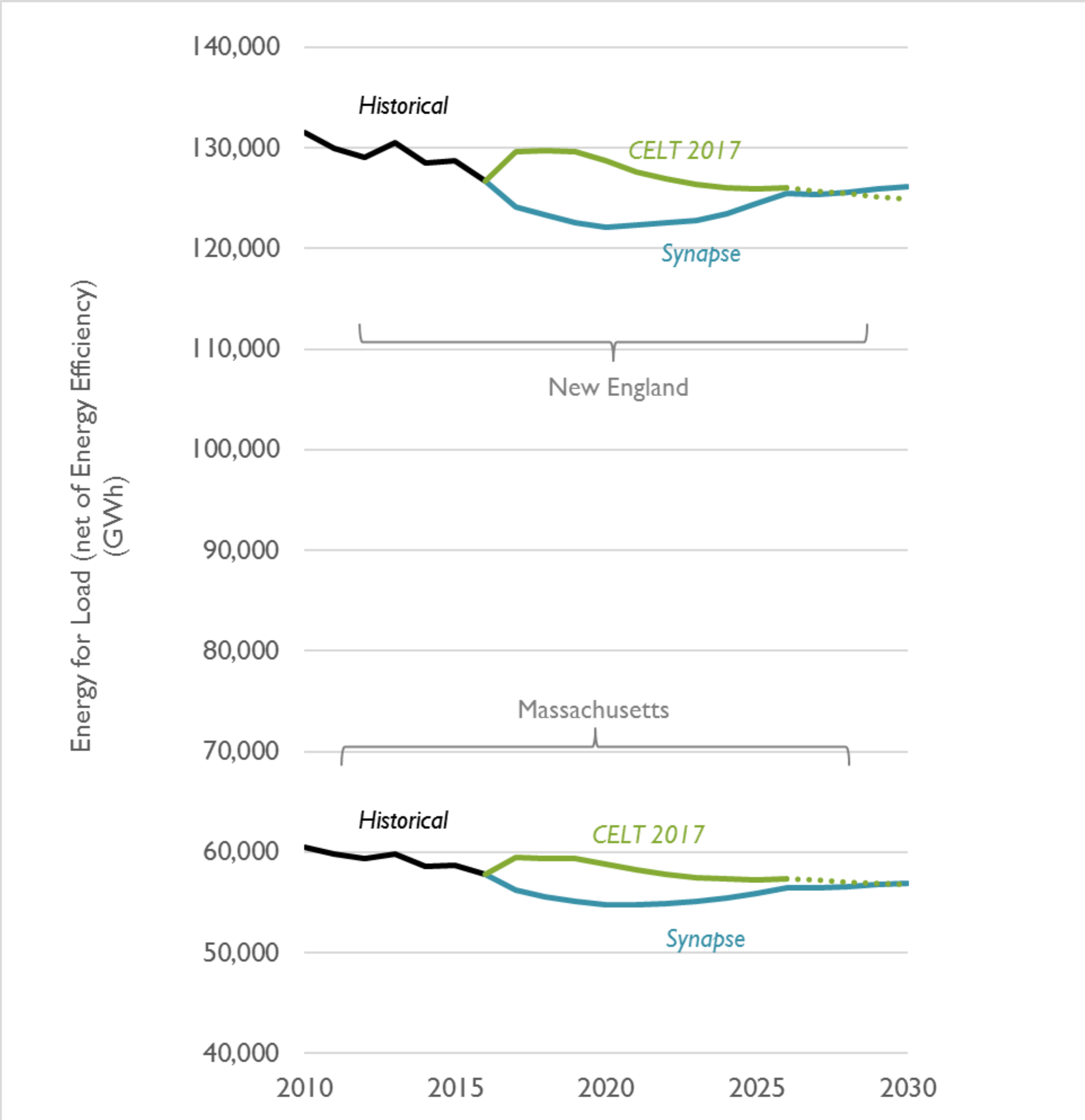
In both sales projections, we increased the Massachusetts sales forecast to reflect electrification from electric vehicles and heat pumps to be consistent with the assumptions in the *Massachusetts Clean Energy and Climate Plan* (CECP) for 2020.[30] We did not make any assumptions regarding incremental vehicle electrification for other New England states.

Figure 19 displays the annual electricity demand for Massachusetts and all six states in New England under both electricity demand projections.

summary of Synapse's proposals to better capture energy efficiency in the CELT forecast methodology can be found at http://www.synapse-energy.com/sites/default/files/Challenges-for-Electric-System-Planning_0.pdf.

[30] The 2015 update to the CECP can be found at http://www.mass.gov/eea/docs/eea/energy/cecp-for-2020.pdf. This level of electrification increases retail sales in Massachusetts by 3.5 percent by 2030, after accounting for energy efficiency.

Figure 19. Load forecast approaches for New England and Massachusetts



Note: All values are at the wholesale level, accounting for T&D losses, and show the net impact from energy efficiency measures but not distributed PV installations. The CELT 2017 forecast for New England has been increased to reflect electric sales in northern Maine, which is part of the New Brunswick ISO (these sales represent about 6 percent of Maine's electric sales, or about 0.06 percent of New England-wide electric sales). All forecasts in this chart have been adjusted to reflect increased levels of electrification in Massachusetts.

New and existing imports from adjacent control areas

Under Massachusetts Chapter 188 Section 83D, Massachusetts distribution utilities were required to solicit, by no later than April 1, 2017, long-term contracts for clean energy generation (including firm service hydro and/or new Class I RPS supply) for a quantity equivalent to 9.45 TWh per year. This clean energy may come from either resources that are currently eligible for compliance with the Class I RPS policy in Massachusetts (including resources located in New England or adjacent control areas) or from new hydroelectricity (including in-region resources, or resources with energy sent over new transmission lines from adjacent control areas).

Any contracts selected from the solicitation process must be executed by no later than December 31, 2022.[31] CECs generated from these resources are assumed to qualify for compliance with the Clean Energy Standard. We assumed this 9.45 TWh of long-term procurement would consist of 90 percent hydro over new transmission (i.e., 8.505 TWh) and 10 percent Class I from resources within ISO New England.[32] We also assumed this new transmission resource would be energized beginning in January 2023, rather than phased in over time.

Separate from this "new import" resource, we modeled net imports to New England (from both New York and Canada) over existing transmission lines as being constant throughout the study period.

Renewable portfolio standards and other renewable policies

As a market fundamentals analysis, the supply, demand, and price dynamics modeled in REMO take into account both the RPS and all other renewable energy policies impacting renewable energy supply and demand. REMO also takes into account, on a case-specific basis, the expected participation of certified generators from adjacent control areas. REMO produces REC price outputs through 2030 for each Class I market in New England. For this analysis, REMO was customized to forecast CEC prices through 2030.

In every modeling run performed, the analysis assumed that all six New England states would meet their renewable portfolio standard requirements, either through the retirement of RECs or ACPs. REMO is constructed to enable the evaluation of multiple market futures, and is commonly used to assess the potential impact on REC price of changes in demand targets, procurement quantity and timing, and availability of eligible supply. In this analysis, we assumed there would be no changes to the RPS policies in any of the six New England states.

Due to the regional nature of electricity markets and the physical interconnections between ISO New England, New York, Quebec, and New Brunswick, New England's Class I REC markets serve as an attractive outlet for renewable energy in neighboring control areas. As such, this analysis accounted for the impact of renewable energy imports. This impact is based on the availability of supply in these

31 Long-term contracting requirements for offshore wind are covered in the section on "Prescribed unit additions."

32 We observe that the modeled quantity of 90 percent of 9.45 TWh is substantially similar to ISO New England's assumption of a 1,200 MW line at 80 percent capacity factor in its comments to MassDEP.

neighboring markets, whether it is contractually committed to serve native load, the ability of interconnection ties to support import transactions, and the price differentials between the markets. Assessment of the role and price impact of neighboring markets is a standard REMO feature; price impacts, however, are dependent on inputs that are customized by case.

REMO allows the evaluation of a range of procurement policy outcomes as well. For this analysis, REMO is programmed to assume that the full volume of existing procurement authority in Massachusetts is fulfilled. These requirements include contracting for 1,600 MW of offshore wind no later than June 30, 2027 (under Section 83C) and up to 9.45 TWh of large hydroelectric and/or Class I renewable energy (under Section 83D).[33] With respect to Section 83D procurement, the REMO model has been customized to assume that 90 percent comes from CES-eligible hydro and 10 percent comes from Class I renewables. Large hydro is not eligible for any Class I RPS in New England, but it is eligible for the Clean Energy Standard when the aforementioned criteria are met. This analysis assumed that the full 1,600 MW of offshore wind is constructed, in 200 MW phases. The first phase becomes operational in the fourth quarter of 2022 and 200 MW phases come online in Q4 of each year after that until the last phase becomes operational in the fourth quarter of 2029.[34] Figure 20 shows the assumed trajectory of offshore wind and incremental Class I renewable energy builds due to Massachusetts contracting authority.

REMO is equipped to model a range of outcomes for policies outside of Massachusetts as well – which impact both large-scale and distributed generation. Decisions specific to this analysis regarding the quantity and timing of large-scale purchases from Connecticut are described below. Standard REMO assumptions for the fulfillment of distributed generation policies are deployed for this analysis and are also described below.

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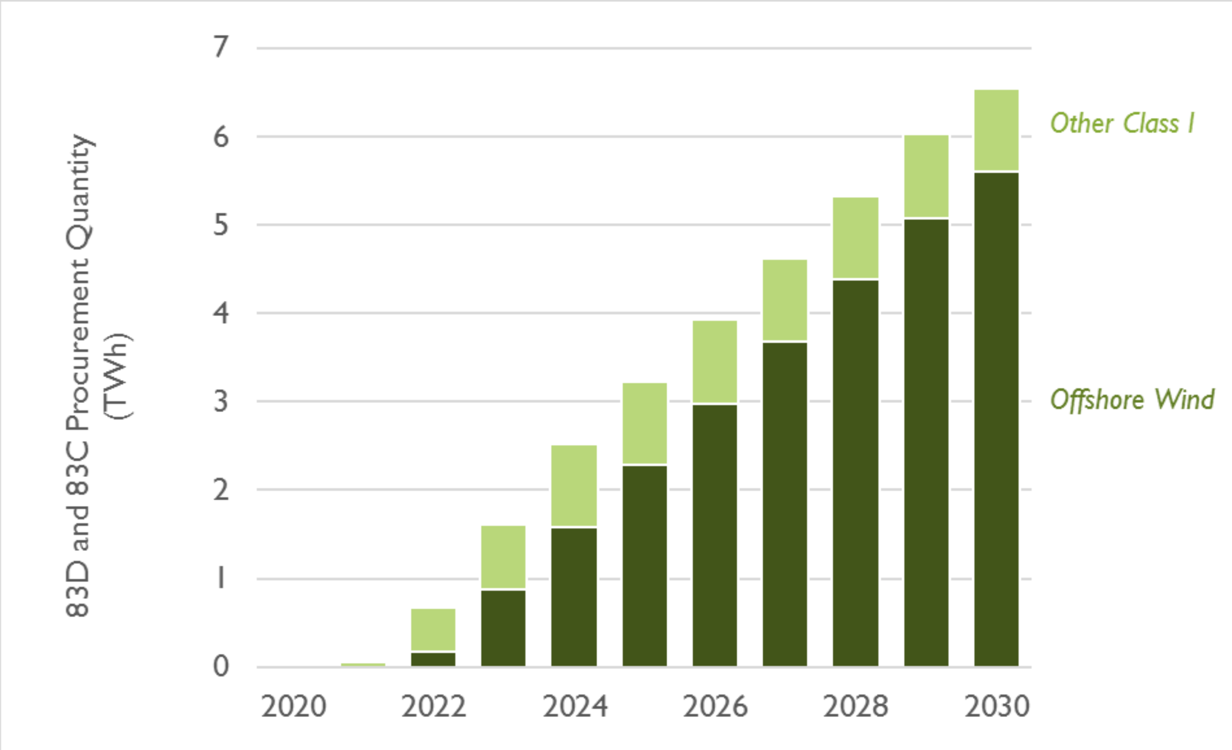
[33] See https://malegislature.gov/Bills/189/House/H4568.

[34] As discussed in the above section "New and existing imports from adjacent control areas," we further assumed that 10 percent of the 83D authority is derived from incremental Class I resources (after accounting for contract attrition), which comes online between 2021 and 2024.

Figure 20. Offshore wind and Class I assumed built in response to Section 83C & 83D requirements



Additional long-term contracting authority—up to approximately 4,000 GWh per year—also exists in Connecticut, under Public Acts 13-303 and 15-107. We assumed that Connecticut is required to competitively procure approximately 900 GWh of Class I renewable energy supply pursuant to Section 6 of Public Act 13-303. This obligation was clarified by the legislature and was originally fulfilled through a 2013 contract with the 250 MW Number 9 wind project. However, transmission-related challenges caused the contract to be terminated. This analysis assumed this required quantity is replaced. The Connecticut procurement requirement has no specified timeframe, however, so this analysis assumed that such procurement is timed to meet market demand. To this end, no additional Connecticut procurement is assumed because Massachusetts procurements ensure that long-term supply exceeds long-term demand. Finally, while Rhode Island has discretional authority to pursue additional long-term contracts, specific quantities are not identified. Because this authority is discretional, we did not assume additional long-term contracts for Rhode Island.

We further assumed that distributed generation programs throughout New England are successfully implemented and result in their expected capacity and generation build. These programs are assumed to contribute Class I RECs as follows: Massachusetts SREC-I (about 710 GWh by 2025), Massachusetts SREC-II (1,800 GWh by 2028), SMART (1,950 GWh by 2025), Connecticut LREC/ZREC (535 GWh by 2020), Connecticut RSIP & SHREC (300 MW), Rhode Island REG (160 MW), Vermont Standard Offer (127.5 MW). Solar is the exclusive distributed generation resource for the Massachusetts programs and the majority resource for the Connecticut, Rhode Island, and Vermont programs.

We did not model any incremental changes or adjustments to annual targets in state RPS policies.

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

For this analysis, we recognized that Massachusetts' Clean Energy Standard will be implemented within the context of a broader marketplace of states and provinces (i.e., ISO New England and adjoining regions of New York and eastern Canada) each with its own renewable mandate and target. Most of these markets have overlapping eligibility criteria for renewable resources, so they compete with one another on the margin for adequate renewable energy supplies to meet their respective demands. Our forecasts of new renewable builds and REC/CEC prices account for this regional approach.

Summary of operating supply, including available imports

Figure 21 shows the estimated production for operating Class I supply by technology in each of the six New England states.[35] This supply has been built in response to the RPS and related policies to date. We also considered existing Class I eligible supply from New York and eastern Canada. New York supply built under 10-year contracts to NYSERDA, in its role as RPS central procurement agent, is available for export to New England as these contracts expire. Figure 22 depicts the quantity and timing of this supply. We developed the forecast of new renewable builds required to meet incremental Clean Energy Standard and RPS demands in two steps: near-term and long-term. In the near term, proposed projects will likely be built subject to probabilistic adjustments to account for deployment timings and individual likelihood of achieving commercial operation. This summary does not include supply developed to fulfill state-specific distributed generation policies such as Massachusetts' SREC-I, SREC-II, and SMART programs. Long-term new renewable builds are determined based on an economic analysis to select the least-cost portfolio of resources from a resource pool sufficient to satisfy the regional Clean Energy Standard and RPS demand in each year.

[35] Production from importing generators is included in this analysis but is not summarized in this chart, which only includes supply located in ISO New England.

Figure 21. Operating supply by technology by state based on estimated annual production

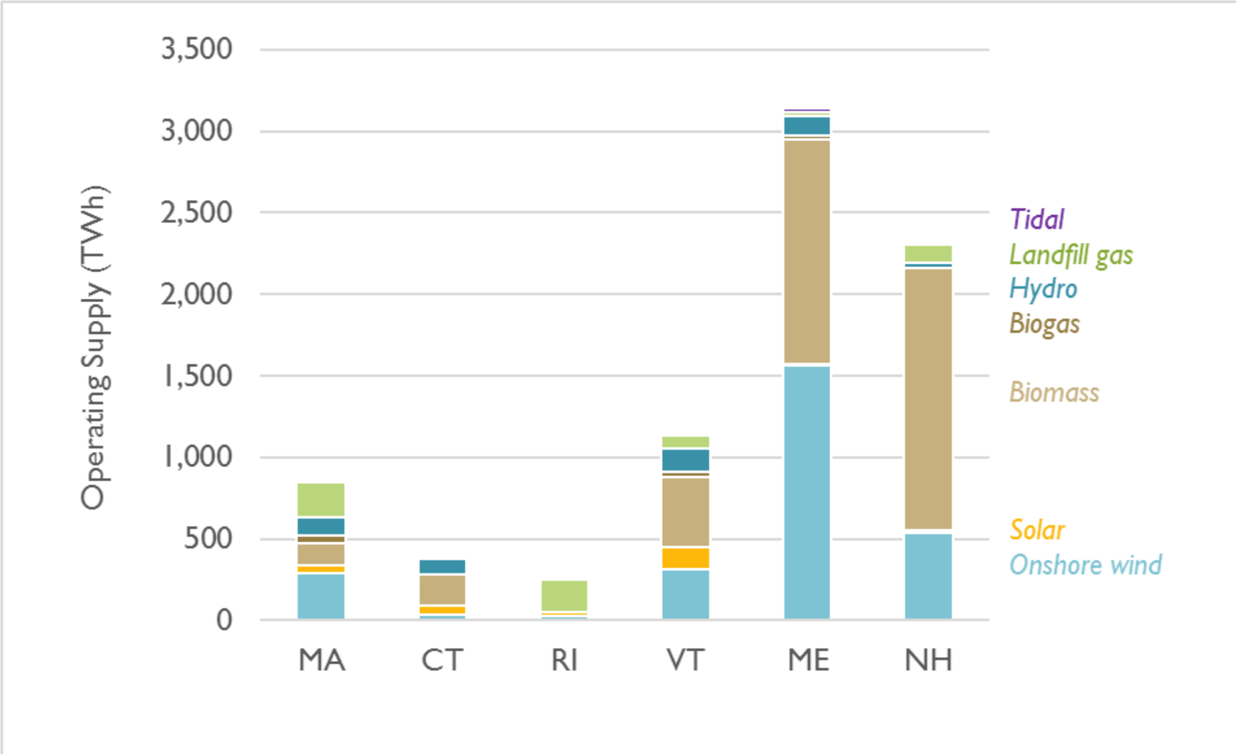
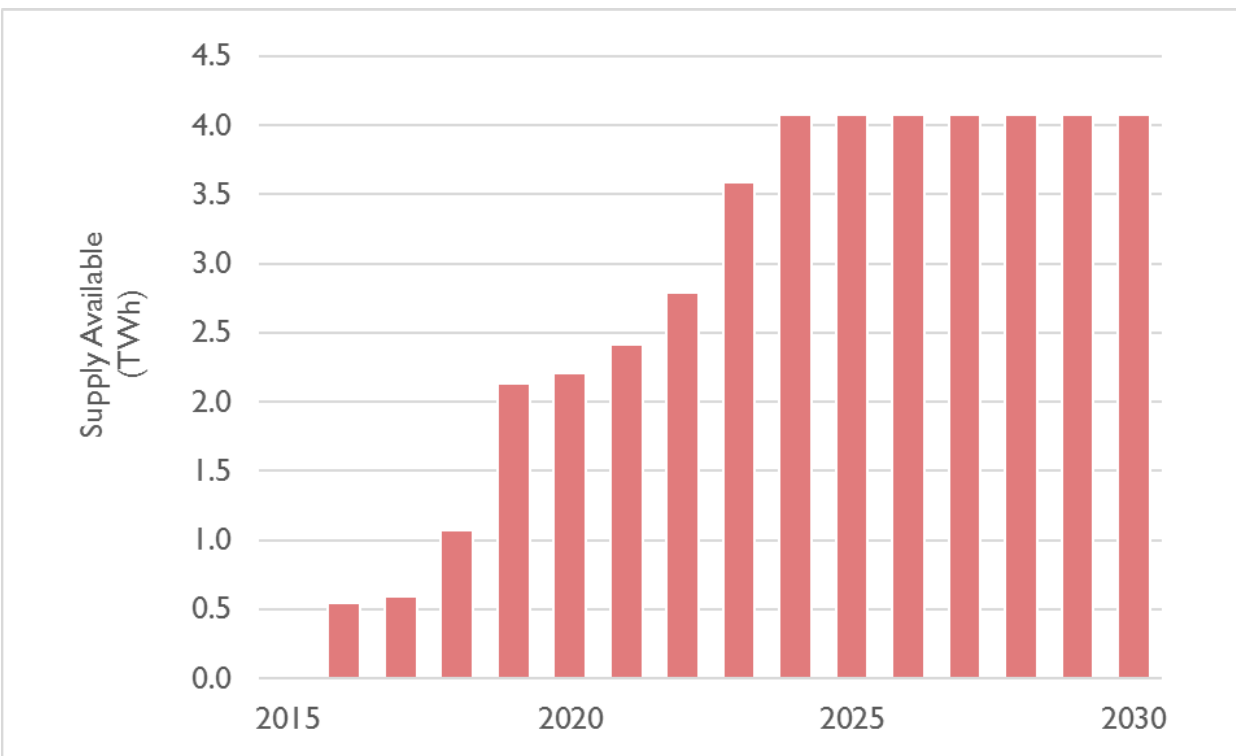


Figure 22. Post-NYSERDA contract supply available for export to New England



Near-term renewable buildout

The near-term committed renewable supply category also includes estimated generation from renewable resources that are developed in proportion to various state policies, including:

- Massachusetts Section 83C Offshore Wind Procurement
- Massachusetts SMART Program
- Massachusetts Section 83D Clean Energy Procurement
- Remaining procurement authority under Connecticut Public Act 13-303 Section 6
- Remaining procurement authority under Connecticut Public Act 13-303 Section 7
- Remaining procurement authority under Connecticut Public Act 15-107
- Rhode Island Replacement of Bowers Wind contract

This analysis also modeled distributed generation throughout the study period. We did not rely on the distributed generation forecast developed by ISO New England in CELT 2017. Instead, this more comprehensive forecast accounts for anticipated distribution resulting from the following policies:

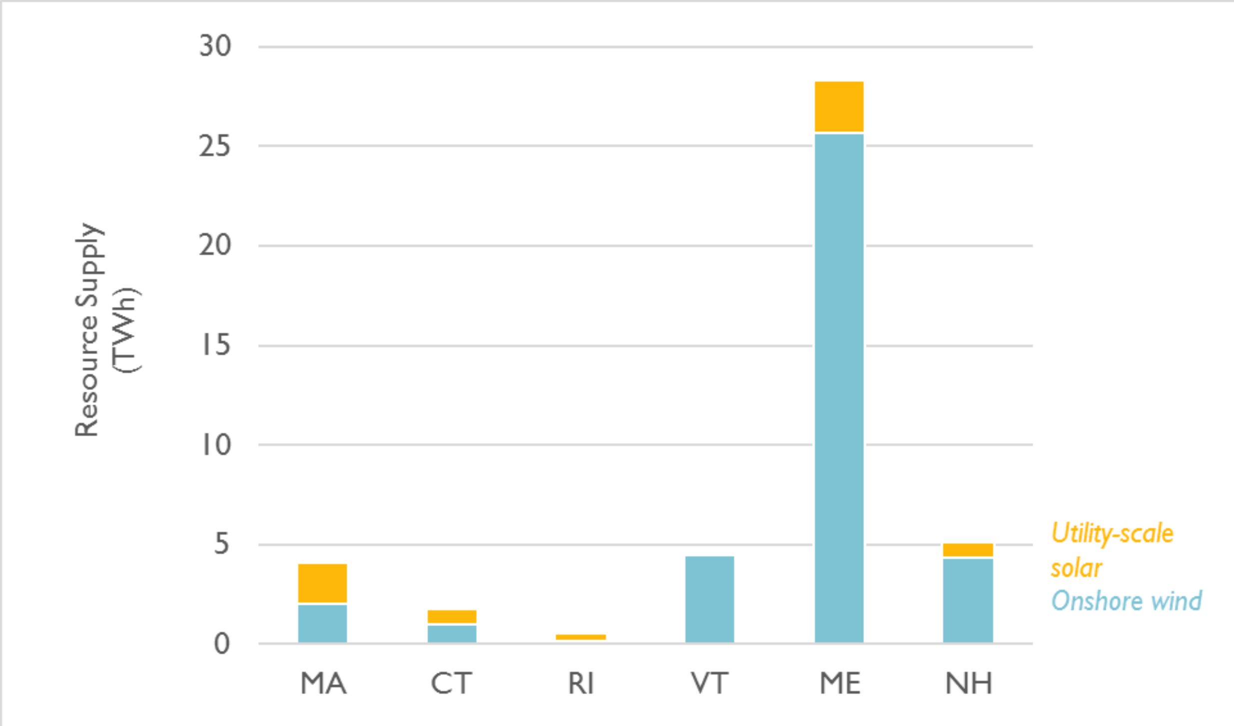
- Massachusetts Solar Carve-out
- Solar Massachusetts Renewable Target (SMART) Program
- Connecticut Low Emissions Renewable Energy Certificate (LREC) and Zero Emissions Renewable Energy Certificate (ZREC) Program
- Connecticut Solar Home Renewable Energy Certificate (SHREC) Program
- Rhode Island Renewable Energy Growth Program
- Vermont Standard Offer Program

Renewable resource potential and cost

The economic analysis used to determine the long-term renewable energy buildouts is conducted using a supply curve model comprised of resource blocks representing the available renewable resource potential within each of the six New England states. Resource availability, including that of land-based wind and utility-scale solar, is described in Figure 23.[36] Not shown in this figure is the potential for offshore wind; in this analysis, we limited offshore wind development potential to Massachusetts and Rhode Island based on current technologies and policies for offshore leasing.

[36] This potential represents the total of technical resource potential of each technology and each state, subject to developable potential adjustment factors driven by assumed probability of permitting success differentiated by technologies and geographical locations.

Figure 23. Long-term renewable resource supply potential by technology by state based on estimated annual production



Note: This chart excludes offshore wind, which is assumed to be policy-driven and is not part of the supply curve.

In this analysis, we assumed that the resources eligible to produce CECs for the Clean Energy Standard are comprised of both (a) all resources eligible for the Massachusetts Class I RPS under 225 CMR 14.00, and (b) hydroelectric resources constructed after December 31, 2010 and—if located outside of ISO New England—delivered via transmission with a commercial operation date after December 31, 2016. Once qualified, such resources will generate a CEC for each MWh of production. CECs, like RECs, will be created, transferred, and settled through the New England Power Pool GIS. As with the RPS, obligated load-serving entities will be required to either settle enough CECs to satisfy their annual Clean Energy Standard obligation or pay an ACP.

Incremental large hydroelectric generation from adjacent control areas—and delivered over new transmission ties—is also eligible for the Massachusetts CES. More than 3,000 MW of new transmission from Canada is proposed and under active development. This analysis assumed new transmission sufficient to deliver hydroelectric generation under long-term contract to Massachusetts utilities in a quantity equal to 90 percent of the 83D obligation (i.e., 8.505 TWh). This new line is expected to be energized on January 1,2023, and large hydro supply delivered to Massachusetts is expected to exceed Clean Energy Standard demand from 2023 through 2030. The result would be a reduction of Clean Energy Standard demand for Class I renewables to zero during this period. This analysis evaluated the extent to which the Clean Energy Standard can be expected to drive Class I renewables in the near and long terms.

Each resource block is defined by a 20-year levelized cost of energy (LCOE) intended to represent the annualized revenue requirement of the supply in nominal $/MWh. It accounts for capital expenditures, ongoing fixed and variable operational expenditures, financing parameters (e.g., cost of capital, capital structure, financing requirements), tax inputs, incentives, performance (i.e., capacity factors), and generator-lead interconnection costs. Renewable resource cost estimates are based on data from NREL's Annual Technology Baseline (adjusted by regional cost factors from the AEO), Greentech Media's November 2015 Cost Trend,[37] the University of Delaware's 2016 *Massachusetts Offshore Wind Future Cost Study*, and Sustainable Energy Advantage research. Table 8 shows the LCOE input assumptions for representative wind, offshore wind, and utility PV generators.[38]

Table 8. LCOE cost inputs of representative generators (all costs in this table are in 2013 dollars)

	Land-based wind (10 MW)	Land-based wind (60 MW)	Land-based wind (125 MW)	Offshore Wind (200+ MW)	Utility PV (20 MW)
Economic Life	20 Years	20 Years	20 Years	20 Years	25 Years
Tax Depreciation	5-Year Modified Accelerated Cost Recovery System (MACRS)				
Debt Cost	6.25%				
Debt Term	18 Years	18 Years	18 Years	18 Years	15 Years
Equity Cost (w/PTC)	~10.5% - ~12.5%				
Debt Equity (w/PTC)	55:45			65:35	35:65
Capital Cost ($/kW)	$2,673	$2,365	$2,097	$3,572	$1,400
Transmission or Interconnection Cost Adder ($/kW)	$193	$110	$133	$986	N/A
Fixed O&M ($/kW-Yr)	$67.59	$67.59	$67.59	$100	$31.61

Throughout the study period, the LCOE values for different resources are expected to undergo multiple changes.[39] Such changes include impacts resulting from technology cost decline and technological improvements, as well as changes to federal incentives (including the investment tax credit for solar and the production tax credit for wind). Figure 24 shows the comparative cost of renewables from 2016 to 2030.[40]

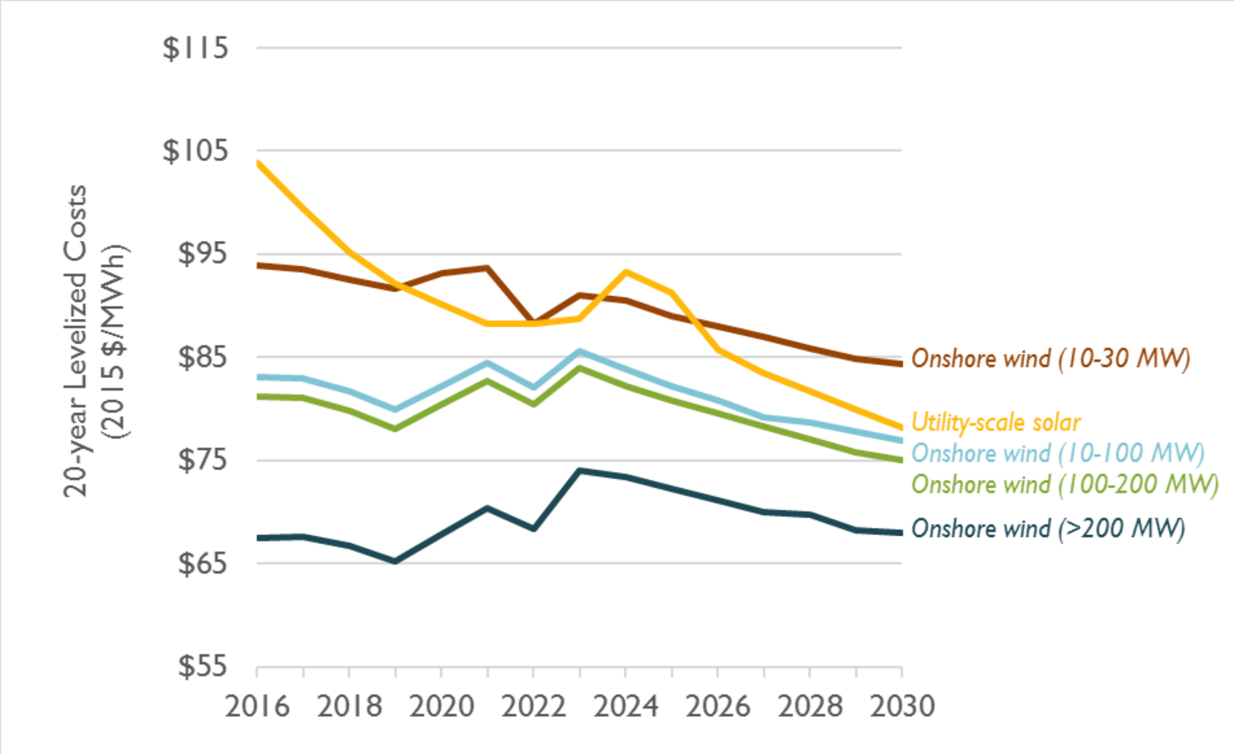
[37] Available at https://www.greentechmedia.com/articles/read/Slideshow-Reaching-250-GW-The-Next-Order-of-Magnitude-in-US-Solar.

[38] The financing inputs assume the generators would be able to monetize 100 percent of the PTC value (or 30 percent ITC value for PV) and secure 20-year long-term bundled power purchase agreements.

[39] A levelized cost of energy is an "average" cost of energy that assumes any up-front capital costs are amortized or spread over the lifetime of the resource, and are added to any fuel, operating, or maintenance costs

[40] Note that operating and maintenance costs for existing conventional generation will be based on the unit-specific data contained in EnCompass. Capital, operating, and maintenance costs for new conventional generation will be based on data from the 2017 AEO.

Figure 24. 20-year levelized cost of renewables of representative renewable energy resource supply blocks (all costs in this figure are in nominal dollars)



Note: This chart excludes offshore wind, which is assumed to be policy-driven and is not part of the supply curve.

The LCOEs shown in Figure 24 assume that the new renewable energy supply will be able to secure 20-year long-term bundled power purchase agreements for RECs, energy, and capacity.

Non-renewable and non-transmission unit additions

Synapse used the EnCompass model to assess dispatch and capacity expansion. The model was built on the information on the universe of generating units known as of December 2015. As a result, we updated the model to include generating units that were operational in 2016 and generating units that are known to be coming online within the next few years.[41]

To construct this unit additions list, we first compiled the units listed as "under construction" in the final 2015 version of EIA form 860.[42] This list was supplemented by the data reported in EIA's Electric Power Monthly.[43] Second, we included any units that cleared in the most recent ISO New England Forward

[41] This does not include renewable resources, which are discussed in the above section.

[42] Available at http://www.eia.gov/electricity/data/eia860/.

[43] Available at http://www.eia.gov/electricity/monthly/.

Capacity Market auctions (FCA-10 and FCA-11).[44] Third, we included units which have been issued environmental permits by MassDEP. Finally, we assumed that 200 MWh of battery storage is online in Massachusetts by 2020, and that 600 MW of battery storage is online by 2025, in line with recommendations to build storage per Governor Baker's Energy Storage Initiative and stipulations of Massachusetts Chapter 188 requiring MA DOER to determine targets for cost-effective storage additions.[45]

Note that we based these addition assumptions on the most-up-to-date information available as of June 2017. This analysis does not account for the delay in the anticipated operational date of Salem Harbor or the delay in anticipated operational date of Burrillville Energy Center 3.[46]

In addition to these prescribed unit additions listed in Table 9 and Table 10, other renewables were added to the model based on Sustainable Energy Advantage's projections of the Class I RPS. If needed, the model was also allowed to dynamically add new capacity in order to ensure that demand requirements are met; however, no such additional capacity was needed to be built in order to ensure the operation of a reliable electric grid.

[44] FCA-11 took place in February 2017 and established capacity obligations for resources through 2021. However, no new fossil resources cleared in this most recent auction. Detail on capacity obligations under for the newest commitment period can be found at https://www.iso-ne.com/static-assets/documents/2017/03/ccp_2020_21_fca_obligations.xlsx.

[45] Based on public comments regarding MA DOER's announcement on determination of storage targets, a total of 600 MW of battery storage was assumed to be added in Massachusetts during the study period. Battery storage was assumed to be added in Massachusetts starting in 2018, with incremental additions of 50 MW per year until 2019 and 100 MW per year from 2020 through 2024. Battery discharge duration was also assumed to increase over time, from 1 hours (as an aggregate average across all battery capacity) in 2018 to 4 hours in 2025. The entirety of the battery systems' capacity was assumed to be available to provide regulation services and to participate in the energy market starting in 2018. Battery capacity was considered "firm," or available to bid into the forward capacity market, once total discharge duration is at least two hours. No other existing battery storage projects were included in this total or in modeling.

[46] The Salem Harbor natural gas combined cycle plant has been delayed until "late 2017" (see http://www.salemnews.com/news/local_news/facing-delay-footprint-tries-to-strike-deal-with-neighbors/article_1f35067c-df84-5049-a981-12d9d3a1d25a.html for more information). Burrillville Energy Center 3 has been delayed until June 2020 (see http://ripr.org/post/controversial-burrillville-power-plant-opening-least-one-year-late#stream/0 for more information).

Table 9. Natural gas additions

State	Plant Name	Utility	Capacity (MW)	Online Year	Fuel Type	Unit Type	Source
CT	Bridgeport Harbor 6	PSEG	484.3	June 2019	Natural Gas	Combined Cycle	FCA10
RI	Burrillville Energy Center 3	Invenergy	485.0	June 2019	Natural Gas	Combined Cycle	FCA10
CT	CPV Towantic Energy Center CTG1	CPV Towantic, LLC	285.0	May 2018	Natural Gas	Combined Cycle	FCA9
CT	CPV Towantic Energy Center CTG2	CPV Towantic, LLC	285.0	May 2018	Natural Gas	Combined Cycle	FCA9
CT	CPV Towantic Energy Center STG	CPV Towantic, LLC	280.5	May 2018	Natural Gas	Combined Cycle	FCA9
MA	Salem Harbor 5	Footprint Salem Harbor Development LP	158.4	June 2017	Natural Gas	Combined Cycle	FCA7
MA	Salem Harbor 6	Footprint Salem Harbor Development LP	158.4	June 2017	Natural Gas	Combined Cycle	FCA7
MA	Salem Harbor 7	Footprint Salem Harbor Development LP	240.7	June 2017	Natural Gas	Combined Cycle	FCA7
MA	Salem Harbor 8	Footprint Salem Harbor Development LP	240.7	June 2017	Natural Gas	Combined Cycle	FCA7
MA	Canal 3	NRG	333.0	June 2019	Natural Gas	Combustion Turbine	FCA10
MA	Medical Area Total Energy Plant CT3	Medical Area Total Egy Plt Inc	13.8	May 2017	Natural Gas	Combustion Turbine	FCA8
MA	Medway Peaker 1	Exelon	194.8	June 2018	Natural Gas	Combustion Turbine	FCA9
CT	Wallingford CTG6	Wallingford Energy LLC	50.0	June 2018	Natural Gas	Combustion Turbine	FCA9
CT	Wallingford CTG7	Wallingford Energy LLC	50.0	June 2018	Natural Gas	Combustion Turbine	FCA9
MA	MIT Central Utilities/Cogen Plant (new)	MIT	44.0	Apr 2020	Natural Gas	Combustion Turbine	MassDEP

Note: The Killingly Energy Center (a 550 MW NGCC) is not included on this list as it has not cleared the capacity market and is not under construction. Similarly, only the first half of the proposed Burrillville Energy Center is included here.

Table 10. Storage additions

State	Plant Name	Utility	Capacity (MW)	Online Year	Fuel Type	Unit Type	Source
MA	Generic Battery I	TBD	600	2018-2025	Battery	Storage	MA DOER

Unit retirements

Just as we specified when new units come online in the EnCompass model, we also plugged in the timing of future unit retirements. Retirement data is based on the 2015 edition of EIA's Form 860, supplemented by ongoing Synapse research (see Table 11, Table 12, and Table 13). In this modeling exercise, we disabled the EnCompass model's ability to dynamically retire unused, uneconomic capacity. Instead, the model only retires the units it is explicitly directed to retire (as described below).[47] Note that several units (i.e., at the Merrimack and Schiller power plants) in the following table do not have announced retirement dates as of yet and are listed for informational purposes only.

Table 11. Coal retirements

State	Plant Name	Utility	Capacity (MW)	Date Offline	Fuel Type	Unit Type	Source
MA	Brayton Point 1	Brayton Point Energy LLC	241.0	June 2017	Coal	Steam Turbine	EIA 860 2015
MA	Brayton Point 2	Brayton Point Energy LLC	241.0	June 2017	Coal	Steam Turbine	EIA 860 2015
MA	Brayton Point 3	Brayton Point Energy LLC	642.6	June 2017	Coal	Steam Turbine	EIA 860 2015
CT	Bridgeport Station 3	PSEG Power Connecticut LLC	400.0	June 2021	Coal	Steam Turbine	Announced by company
NH	Merrimack 1	Public Service Co of NH	113.6	-	Coal	Steam Turbine	EIA 860 2015
NH	Merrimack 2	Public Service Co of NH	345.6	-	Coal	Steam Turbine	EIA 860 2015
NH	Schiller 4	Public Service Co of NH	50.0	-	Coal	Steam Turbine	EIA 860 2015
NH	Schiller 5	Public Service Co of NH	50.0	-	Coal/ Biomass	Steam Turbine	EIA 860 2015
NH	Schiller 6	Public Service Co of NH	50.0	-	Coal	Steam Turbine	EIA 860 2015

Note: The Merrimack and Schiller power plants in the above table do not currently have announced retirement dates. These two plants represent the remaining coal capacity in New England, and are listed for informational purposes only. Eversource is under an NH PUC requirement to sell the Merrimack and Schiller plants by the end of 2017.

Table 12. Nuclear retirements

State	Plant Name	Utility	Capacity (MW)	Date Offline	Fuel Type	Unit Type	Source
MA	Pilgrim Nuclear Power Station 1	Entergy Nuclear Generation Co	670.0	May 2019	Nuclear	Steam Turbine	EIA 860 2015

[47] This approach towards economic retirements is consistent with the ISO's assumptions in its 2016 Economic Study non-retirement cases.

Table 13. Natural gas and oil retirements

State	Plant Name	Utility	Capacity (MW)	Date Offline	Fuel Type	Unit Type	Source
MA	Brayton Point 4	Brayton Point Energy LLC	475.5	June 2017	Oil	Steam Turbine	EIA 860 2015
CT	Bridgeport Station 4	PSEG Power Connecticut LLC	18.6	May 2017	Oil	Combustion Turbine	EIA 860 2015
MA	Exelon L Street GT1	Exelon Power	16.0	Oct 2016	Oil	Combustion Turbine	Electric Power Monthly
MA	MIT Central Utilities/Cogen Plant CTG1	MIT	21.2	Apr 2020	Natural Gas	Combustion Turbine	EIA 860 2015

Intra-regional transmission additions

In all scenarios, we assumed that New England builds out incremental transmission in the region in line with the ISO New England capacity zone development for the 11th Forward Capacity Auction.[48] This includes 575 MW of transfer capacity on the North-South interface in 2019, followed by an incremental 50 MW on the same interface in 2020 and an incremental 100 MW of transfer capacity on the Northern New England-Scobie interface in 2020.

The Regional Greenhouse Gas Initiative

RGGI is a nine-state program consisting of the six New England states, Delaware, Maryland, and New York. RGGI imposes a decreasing cap on allowable CO_2 emissions from most electric generators of 2.5 percent per year until 2020. Emission caps for 2021 and years afterward have not yet been established.[49] A program review is currently underway to determine what should happen in the RGGI program for all years after 2020, with options including a continuation of the 2.5 percent reduction, or an implementation of a more stringent reduction at 3.5 percent per year.

In this analysis, we modeled the RGGI program as an effective price. While the price for RGGI allowances is uncertain at this time, we calculated a RGGI allowance price trajectory for the main scenarios based on an average of the April 2016 prices modeled by RGGI in its 2016 Program Review under a 2.5 percent reduction scenario and a 3.5 reduction scenario.[50] In the alternative RGGI price sensitivity, we calculated

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[48] ISO New England. "Forward Capacity Auction 11 Transmission Transfer Capabilities & Capacity Zone Development." March 22, 2016. https://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf.

[49] At this point, RGGI is expected to require more stringent emission limits for the nine-state region than allowed for the states under the federal Clean Power Plan. Given that the Clean Power Plan is expected to be less stringent than RGGI, it has not been modeled in this analysis.

[50] For 2025, this results in a RGGI allowance price of $19 per metric ton. In ISO New England's comments to MassDEP, it assumed a 2025 RGGI allowance price of $19 per short ton, or about $21 per metric ton.

a RGGI price trajectory based on the three scenarios released in June 2017: a 2.5 percent reduction scenario, a 3.0 percent reduction scenario, and a 3.5 percent reduction scenario. [51, 52]

[51] RGGI price data for these scenarios can be found at https://www.rggi.org/design/2016-program-review/rggi-meetings.

52 Note that ISO New England modeled a 2030 RGGI price of $24/short ton (in 2015 dollars) in its 2016 Economic Study (available at https://www.iso-ne.com/static-assets/documents/2017/04/a6_2016_economic_study_carbon_cost_.pdf). The 2030 RGGI price used in the main Reference Case and main Policy Case is $23/short ton in 2015 dollars.

APPENDIX C. NATURAL GAS PRICE FORECAST

In this analysis, we modeled two different natural gas prices: a medium natural gas price, approximating the most likely future for natural gas prices in New England, and a high natural gas price, approximating what prices would be in a future in which natural gas production and availability were more constrained.

Projecting the price of natural gas

To calculate the medium natural gas price, we relied on NYMEX futures for monthly Henry Hub gas prices through December 2019.[53] For all years after 2019, we assumed the annual average prices projected for Henry Hub in the AEO 2017 Reference case with no Clean Power Plan.[54] We applied the trends in average monthly prices observed in the NYMEX futures to this longer-term natural gas price to develop long-term monthly trends.

Next, we applied the NYMEX futures price data for the basis price of the Algonquin Citygate from Henry Hub (i.e., the difference in price between Henry Hub and Algonquin Citygate) from June 2017 through December 2019.[55] For all months before 2020, the monthly NYMEX futures prices for Henry Hub were added to the Algonquin Citygate basis to forecast Algonquin Citygate Prices. Using the average basis prices from each month in 2017 through 2019, we calculated the average monthly basis price for Algonquin Citygate from Henry Hub. For all months after 2020, the average monthly basis price for Algonquin Citygate were added to the forecasted monthly Henry Hub price.

For the high gas price sensitivity, we followed the same methodology, except instead of using the 2020–2030 prices as projected in the AEO 2017 Reference case with No Clean Power Plan, we used the annual average price change from the AEO 2017 low oil and gas resource and technology case. From 2019 to 2030, the Henry Hub natural gas price in this case is expected to grow by 5.0 percent each year, compared to 1.8 percent per year in the AEO 2017 Reference case with no Clean Power Plan.

Note that these price forecasts do not account for possible price changes associated with the completed Algonquin Incremental Market (AIM) expansion pipeline project or the proposed Tennessee Gas Pipeline – Connecticut Expansion, the Atlantic Bridge pipeline projects, or any other proposed projects beyond what may be factored into the NYMEX futures. At this time, sufficient data is not available to determine the impact of the already existing AIM expansion pipeline project or the possible impacts of the other

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53 Henry Hub is the major trading hub for natural gas in the United States. NYMEX futures data is freely available at http://www.cmegroup.com/trading/products/.

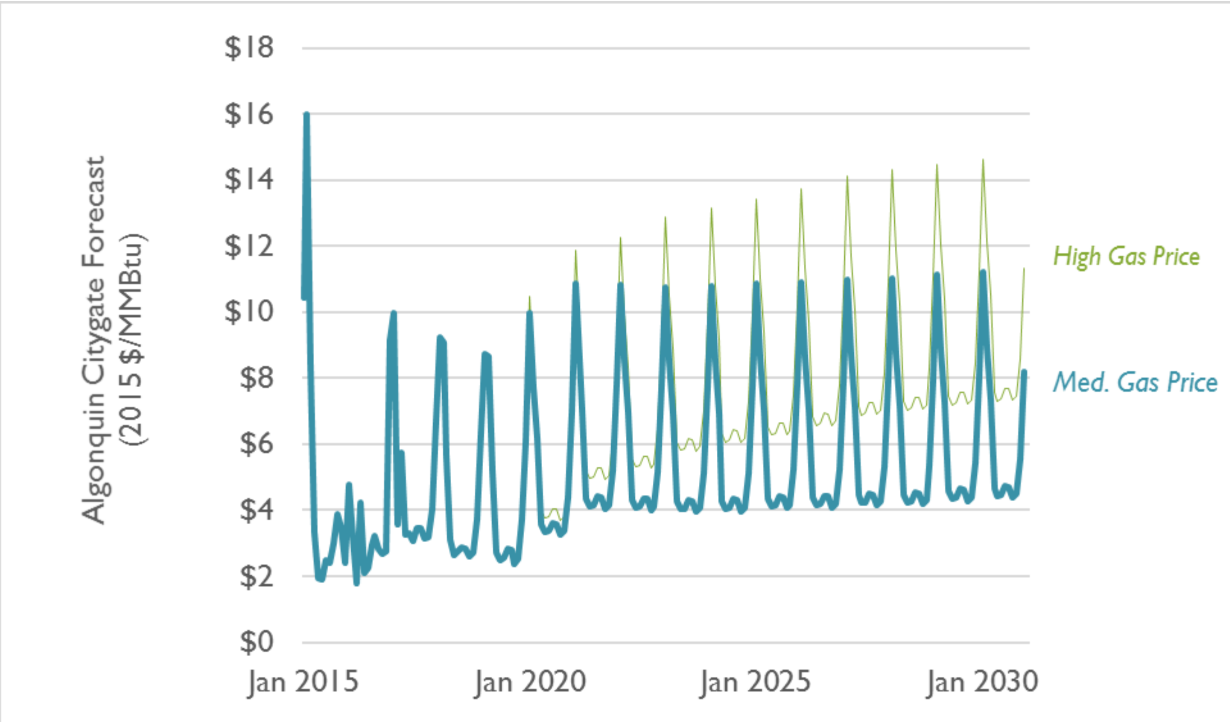
54 From 2019 to 2030, the average annual price change for Henry Hub in the AEO 2017 Reference case and the AEO 2017 Reference case with No Clean Power Plan are almost identical (2.0 percent versus 1.8 percent, respectively).

55 Algonquin Citygate is New England's main pricing hub for natural gas used in electricity generation. Natural gas-fired units in Maine and New Hampshire were assumed to receive gas from the Dracut delivery point. However, Algonquin costs were used as a proxy for Dracut costs due to a lack of independent pricing data.

two projects. These natural gas price forecasts also do not account for possible annual or seasonal changes to natural gas prices resulting from changes to natural gas demand (such as those caused by increased renewables, new imports, or increased energy efficiency).

Figure 25 shows the monthly natural gas price forecasts used in the medium and high scenarios.[56]

Figure 25. Monthly natural gas price forecasts



In EnCompass, we modeled natural gas-fired generating units as receiving fuel from one of several delivery points. Each of these has a different cost profile. We assumed that Algonquin Citygate would be the delivery point for all units in the region, with the following exceptions: the Mystic combined-cycle plant in Massachusetts was assumed to receive LNG from the Everett terminal, and the Milford Power Plant and Bridgeport facilities in Connecticut were assumed to use the Iroquois delivery point.[57] As such, the Algonquin price impacts the delivered fuel costs of most of the fossil-fired units in New England.

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[56] For 2025, this forecast results in an annual average natural gas price of $5.77 per MMBtu. In ISO New England's comments, it assumed a 2025 natural gas price of $5.39 per MMBtu.

[57] In addition, we assumed gas-fired units in Maine and New Hampshire would receive gas from the Dracut delivery point. However, Algonquin costs were used as a proxy for Dracut costs due to a lack of independent pricing data.

APPENDIX D. DETAILED CAPACITY, GENERATION, AND EMISSIONS TABLES

Table 14. Electric generating capacity detail (GW) for Massachusetts and New England (inclusive of Massachusetts)

	2016	…	2018		2019		2020		…	2025		…	2030	
		…	Ref	Policy	Ref	Policy	Ref	Policy	…	Ref	Policy	…	Ref	Policy
Massachusetts	**15.3**	…	**16.0**	**16.0**	**16.8**	**16.8**	**16.5**	**16.5**	…	**18.5**	**18.5**	…	**19.4**	**19.4**
Renewable resources	**3.6**	…	**4.8**	**4.8**	**5.2**	**5.2**	**5.5**	**5.5**	…	**7.1**	**7.1**	…	**8.0**	**8.0**
Biomass	0.3	…	0.2	0.2	0.2	0.2	0.2	0.2	…	0.2	0.2	…	0.2	0.2
Hydro	2.0	…	2.0	2.0	2.0	2.0	2.0	2.0	…	2.1	2.1	…	2.1	2.1
Landfill Gas	0.1	…	0.1	0.1	0.1	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Solar: Distributed	0.6	…	1.4	1.4	1.6	1.6	1.7	1.7	…	2.3	2.3	…	2.3	2.3
Solar: Utility-scale	0.6	…	1.0	1.0	1.2	1.2	1.3	1.3	…	1.7	1.7	…	1.7	1.7
Wind: Offshore	-	…	-	-	-	-	-	-	…	0.7	0.7	…	1.6	1.6
Wind: Onshore	0.1	…	0.1	0.1	0.2	0.2	0.2	0.2	…	0.2	0.2	…	0.2	0.2
Other resources	**11.7**	…	**11.1**	**11.1**	**11.5**	**11.5**	**11.0**	**11.0**	…	**11.4**	**11.4**	…	**11.4**	**11.4**
Natural gas CC	6.4	…	7.0	7.0	7.0	7.0	7.0	7.0	…	7.0	7.0	…	7.0	7.0
Natural gas CT	3.6	…	3.4	3.4	3.7	3.7	3.8	3.8	…	3.7	3.7	…	3.7	3.7
Coal	1.1	…	-	-	-	-	-	-	…	-	-	…	-	-
Nuclear	0.7	…	0.7	0.7	0.7	0.7	-	-	…	-	-	…	-	-
Battery	-	…	0.0	0.0	0.1	0.1	0.2	0.2	…	0.6	0.6	…	0.6	0.6
New England	**36.7**	…	**39.0**	**39.0**	**40.7**	**40.8**	**40.6**	**40.8**	…	**42.9**	**42.9**	…	**43.9**	**43.9**
Renewable resources	**7.8**	…	**9.8**	**9.8**	**10.5**	**10.6**	**11.1**	**11.2**	…	**13.4**	**13.4**	…	**14.3**	**14.3**
Biomass	1.2	…	1.0	1.0	0.9	1.1	1.0	1.1	…	0.9	0.9	…	0.9	0.9
Hydro	3.7	…	3.7	3.7	3.7	3.7	3.7	3.7	…	3.9	3.9	…	3.9	3.9
Landfill Gas	0.1	…	0.1	0.1	0.1	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Solar: Distributed	0.9	…	1.9	1.9	2.1	2.1	2.2	2.2	…	2.9	2.9	…	2.9	2.9
Solar: Utility-scale	0.9	…	1.6	1.6	2.2	2.2	2.5	2.5	…	3.1	3.1	…	3.1	3.1
Wind: Offshore	0.0	…	0.0	0.0	0.0	0.0	0.0	0.0	…	0.7	0.7	…	1.6	1.6
Wind: Onshore	1.0	…	1.4	1.4	1.4	1.4	1.5	1.5	…	1.8	1.8	…	1.8	1.8
Other resources	**28.9**	…	**29.2**	**29.2**	**30.2**	**30.2**	**29.6**	**29.6**	…	**29.6**	**29.6**	…	**29.6**	**29.6**
Natural gas CC	13.9	…	15.4	15.4	15.9	15.9	15.9	15.9	…	15.9	15.9	…	15.9	15.9
Natural gas CT	8.9	…	8.8	8.8	9.1	9.1	9.2	9.2	…	9.1	9.1	…	9.1	9.1
Coal	2.0	…	0.9	0.9	0.9	0.9	0.9	0.9	…	0.5	0.5	…	0.5	0.5
Nuclear	4.1	…	4.1	4.1	4.1	4.1	3.4	3.4	…	3.4	3.4	…	3.4	3.4
Battery	-	…	0.0	0.0	0.1	0.1	0.2	0.2	…	0.6	0.6	…	0.6	0.6

Notes: In this table, "Biomass" includes biomass, biodiesel, biogas, and municipal solid waste. "Landfill gas" includes fuel cells, landfill gas, and low emission advanced renewables. "Hydro" includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as "0.0" are greater than 0 but less than 0.05; values shown as "-" are truly zero. Capacity from gas-fired steam turbines is grouped with "Natural gas CT." Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their prime mover type.

Table 15. In-state and in-region generation detail (TWh) for Massachusetts and New England (inclusive of Massachusetts)

	2016	...	2018		2019		2020		...	2025		...	2030	
		...	Ref	Policy	Ref	Policy	Ref	Policy	...	Ref	Policy	...	Ref	Policy
Massachusetts	**32.8**	...	**31.2**	**31.2**	**26.3**	**26.2**	**24.5**	**24.6**	...	**22.7**	**22.8**	...	**25.0**	**25.0**
Renewable resources	**4.4**	...	**5.5**	**5.5**	**6.1**	**6.1**	**6.5**	**6.6**	...	**10.0**	**10.0**	...	**13.2**	**13.2**
Biomass	1.9	...	1.8	1.8	1.8	1.8	1.8	1.9	...	1.8	1.8	...	1.8	1.8
Hydro	0.4	...	0.6	0.6	0.6	0.6	0.6	0.6	...	0.6	0.6	...	0.6	0.6
Landfill Gas	0.3	...	0.3	0.3	0.3	0.3	0.3	0.3	...	0.3	0.3	...	0.3	0.3
Solar: Distributed	0.7	...	1.3	1.3	1.5	1.5	1.7	1.7	...	2.4	2.4	...	2.5	2.5
Solar: Utility-scale	0.8	...	1.2	1.2	1.4	1.4	1.6	1.6	...	2.0	2.0	...	1.9	1.9
Wind: Offshore	-	...	-	-	-	-	-	-	...	2.3	2.3	...	5.6	5.6
Wind: Onshore	0.3	...	0.3	0.3	0.4	0.4	0.4	0.4	...	0.5	0.5	...	0.5	0.5
Other resources	**28.3**	...	**25.7**	**25.7**	**20.2**	**20.0**	**18.0**	**18.0**	...	**12.8**	**12.8**	...	**11.8**	**11.9**
Natural gas CC	20.5	...	19.5	19.5	18.0	17.9	17.7	17.7	...	12.5	12.5	...	11.6	11.6
Natural gas CT	0.7	...	0.4	0.4	0.3	0.3	0.3	0.3	...	0.3	0.3	...	0.2	0.2
Coal	1.3	...	-	-	-	-	-	-	...	-	-	...	-	-
Nuclear	5.8	...	5.8	5.8	1.8	1.8	-	-	...	-	-	...	-	-
Battery	-	...	-	-	-	-	-	-	...	-	-	...	-	-
New England	**125.1**	...	**123.2**	**123.2**	**122.4**	**122.4**	**122.0**	**122.0**	...	**124.3**	**124.3**	...	**126.0**	**126.0**
Renewable resources	**19.5**	...	**21.5**	**21.5**	**22.3**	**23.1**	**23.3**	**24.4**	...	**28.6**	**28.6**	...	**31.7**	**31.7**
Biomass	7.8	...	6.6	6.6	6.2	7.0	6.3	7.4	...	6.1	6.1	...	6.1	6.1
Hydro	6.0	...	6.3	6.3	6.4	6.4	6.5	6.4	...	6.9	6.9	...	7.0	7.0
Landfill Gas	0.8	...	0.8	0.8	0.9	0.9	0.9	0.9	...	0.8	0.8	...	0.7	0.7
Solar: Distributed	0.9	...	1.8	1.8	2.1	2.1	2.4	2.4	...	3.2	3.2	...	3.2	3.2
Solar: Utility-scale	1.2	...	2.0	2.0	2.8	2.8	3.3	3.3	...	4.0	4.0	...	3.8	3.8
Wind: Offshore	0.0	...	0.1	0.1	0.1	0.1	0.1	0.1	...	2.4	2.4	...	5.7	5.7
Wind: Onshore	2.7	...	3.8	3.8	3.9	3.9	4.0	4.0	...	5.2	5.2	...	5.2	5.2
Other resources	**84.5**	...	**80.7**	**80.7**	**79.1**	**78.3**	**77.5**	**76.5**	...	**66.3**	**66.3**	...	**64.8**	**64.8**
Natural gas CC	48.1	...	46.9	46.9	48.7	48.0	50.6	49.5	...	38.3	38.3	...	37.8	37.8
Natural gas CT	1.1	...	0.6	0.6	0.5	0.5	0.5	0.5	...	0.4	0.4	...	0.4	0.4
Coal	2.2	...	1.0	1.0	0.9	0.9	1.0	1.0	...	0.5	0.5	...	0.2	0.2
Nuclear	33.0	...	32.2	32.2	29.0	29.0	25.5	25.5	...	27.2	27.2	...	26.4	26.4
Battery	-	...	-	-	-	-	-	-	...	-	-	...	-	-
Net Imports	**21.1**	...	**21.0**	**21.0**	**20.9**	**20.9**	**21.1**	**21.1**	...	**29.4**	**29.4**	...	**29.5**	**29.5**
New Hydro	0.0	...	0.0	0.0	0.0	0.0	0.0	0.0	...	8.5	8.5	...	8.5	8.5
Other Net Imports	21.1	...	21.0	21.0	20.9	20.9	21.1	21.1	...	20.9	20.9	...	21.0	21.0

Notes: In this table, "Biomass" includes biomass, biodiesel, biogas, and municipal solid waste. "Landfill gas" includes fuel cells, landfill gas, and low emission advanced renewables. "Hydro" includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as "0.0" are greater than 0 but less than 0.05; values shown as "-" are truly zero. Generation from gas-fired steam turbines is grouped with "Natural gas CT." Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their prime mover type.

Table 16. In-state and in-region fossil fuel CO_2 emissions detail for Massachusetts and New England (inclusive of Massachusetts) (million metric tons CO_2)

	2016	…	2018		2019		2020		…	2025		…	2030	
		…	Ref	Policy	Ref	Policy	Ref	Policy	…	Ref	Policy	…	Ref	Policy
Massachusetts	**10.1**	…	**8.3**	**8.3**	**7.6**	**7.5**	**7.4**	**7.4**	…	**5.3**	**5.3**	…	**4.9**	**5.0**
Affected resources	**9.8**	…	**8.1**	**8.1**	**7.4**	**7.3**	**7.2**	**7.2**	…	**5.1**	**5.1**	…	**4.7**	**4.7**
Natural gas CC	8.6	…	8.0	8.0	7.3	7.2	7.1	7.1	…	5.0	5.1	…	4.7	4.7
Natural gas CT	0.2	…	0.2	0.2	0.1	0.1	0.1	0.1	…	0.0	0.0	…	0.0	0.0
Coal	1.0	…	-	-	-	-	-	-	…	-	-	…	-	-
Other resources	**0.3**	…	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	…	**0.2**	**0.2**	…	**0.2**	**0.2**
Natural gas CC	0.1	…	0.1	0.1	0.1	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Natural gas CT	0.2	…	0.1	0.1	0.1	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Coal	-	…	-	-	-	-	-	-	…	-	-	…	-	-
New England	**22.4**	…	**20.4**	**20.4**	**20.7**	**20.4**	**21.4**	**21.0**	…	**15.9**	**15.9**	…	**15.5**	**15.5**
Affected resources	**9.8**	…	**8.1**	**8.1**	**7.4**	**7.3**	**7.2**	**7.2**	…	**5.1**	**5.1**	…	**4.7**	**4.7**
Natural gas CC	8.6	…	8.0	8.0	7.3	7.2	7.1	7.1	…	5.0	5.1	…	4.7	4.7
Natural gas CT	0.2	…	0.2	0.2	0.1	0.1	0.1	0.1	…	0.0	0.0	…	0.0	0.0
Coal	1.0	…	-	-	-	-	-	-	…	-	-	…	-	-
Other resources	**12.6**	…	**12.3**	**12.3**	**13.4**	**13.1**	**14.2**	**13.8**	…	**10.9**	**10.8**	…	**10.8**	**10.8**
Natural gas CC	11.2	…	11.0	11.0	12.2	12.0	13.0	12.6	…	10.2	10.2	…	10.4	10.4
Natural gas CT	0.5	…	0.3	0.3	0.2	0.2	0.2	0.2	…	0.2	0.2	…	0.2	0.2
Coal	0.9	…	1.0	1.0	0.9	0.9	1.0	1.0	…	0.5	0.5	…	0.2	0.2

Note: For comparison purposes, emissions from affected resources under 310 CMR 7.74 are shown in the "Affected resources" section in the Reference Case, although the regulations were not modeled as being in effect in the Reference Case. Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their primary fuel type. Emissions associated with biomass or municipal solid waste are not included in this table.

Table 17. Electric generating capacity detail (GW) for Massachusetts and New England (inclusive of Massachusetts) under the alternative sales forecast

	2016	...	2018		2019		2020		...	2025		...	2030	
		...	Ref	Policy	Ref	Policy	Ref	Policy	...	Ref	Policy	...	Ref	Policy
Massachusetts	**15.3**	...	**16.0**	**16.0**	**16.8**	**16.8**	**16.5**	**16.5**	...	**18.5**	**18.5**	...	**19.4**	**19.4**
Renewable resources	**3.6**	...	**4.8**	**4.9**	**5.2**	**5.2**	**5.5**	**5.5**	...	**7.1**	**7.1**	...	**8.0**	**8.0**
Biomass	0.3	...	0.2	0.2	0.2	0.2	0.2	0.3	...	0.2	0.2	...	0.2	0.2
Hydro	2.0	...	2.0	2.0	2.0	2.0	2.0	2.0	...	2.1	2.1	...	2.1	2.1
Landfill Gas	0.1	...	0.1	0.1	0.1	0.1	0.1	0.1	...	0.1	0.1	...	0.1	0.1
Solar: Distributed	0.6	...	1.4	1.4	1.6	1.6	1.7	1.7	...	2.3	2.3	...	2.3	2.3
Solar: Utility-scale	0.6	...	1.0	1.0	1.2	1.2	1.3	1.3	...	1.7	1.7	...	1.7	1.7
Wind: Offshore	-	...	-	-	-	-	-	-	...	0.7	0.7	...	1.6	1.6
Wind: Onshore	0.1	...	0.1	0.1	0.2	0.2	0.2	0.2	...	0.2	0.2	...	0.2	0.2
Other resources	**11.7**	...	**11.1**	**11.1**	**11.5**	**11.5**	**11.0**	**11.0**	...	**11.4**	**11.4**	...	**11.4**	**11.4**
Natural gas CC	6.4	...	7.0	7.0	7.0	7.0	7.0	7.0	...	7.0	7.0	...	7.0	7.0
Natural gas CT	3.6	...	3.4	3.4	3.7	3.7	3.8	3.8	...	3.7	3.7	...	3.7	3.7
Coal	1.1	...	-	-	-	-	-	-	...	-	-	...	-	-
Nuclear	0.7	...	0.7	0.7	0.7	0.7	-	-	...	-	-	...	-	-
Battery	-	...	0.0	0.0	0.1	0.1	0.2	0.2	...	0.6	0.6	...	0.6	0.6
New England	**36.7**	...	**39.0**	**39.1**	**40.7**	**40.9**	**40.7**	**40.9**	...	**42.9**	**42.9**	...	**43.9**	**43.9**
Renewable resources	**7.8**	...	**9.8**	**9.9**	**10.5**	**10.8**	**11.1**	**11.3**	...	**13.4**	**13.4**	...	**14.3**	**14.3**
Biomass	1.2	...	1.0	1.1	0.9	1.2	1.0	1.2	...	0.9	0.9	...	0.9	0.9
Hydro	3.7	...	3.7	3.7	3.7	3.7	3.7	3.7	...	3.9	3.9	...	3.9	3.9
Landfill Gas	0.1	...	0.1	0.1	0.1	0.1	0.1	0.1	...	0.1	0.1	...	0.1	0.1
Solar: Distributed	0.9	...	1.9	1.9	2.1	2.1	2.2	2.2	...	2.9	2.9	...	2.9	2.9
Solar: Utility-scale	0.9	...	1.6	1.6	2.2	2.2	2.5	2.5	...	3.1	3.1	...	3.1	3.1
Wind: Offshore	0.0	...	0.0	0.0	0.0	0.0	0.0	0.0	...	0.7	0.7	...	1.6	1.6
Wind: Onshore	1.0	...	1.4	1.4	1.4	1.4	1.5	1.5	...	1.8	1.8	...	1.8	1.8
Other resources	**28.9**	...	**29.2**	**29.2**	**30.2**	**30.2**	**29.6**	**29.6**	...	**29.6**	**29.6**	...	**29.6**	**29.6**
Natural gas CC	13.9	...	15.4	15.4	15.9	15.9	15.9	15.9	...	15.9	15.9	...	15.9	15.9
Natural gas CT	8.9	...	8.8	8.8	9.1	9.1	9.2	9.2	...	9.1	9.1	...	9.1	9.1
Coal	2.0	...	0.9	0.9	0.9	0.9	0.9	0.9	...	0.5	0.5	...	0.5	0.5
Nuclear	4.1	...	4.1	4.1	4.1	4.1	3.4	3.4	...	3.4	3.4	...	3.4	3.4
Battery	-	...	0.0	0.0	0.1	0.1	0.2	0.2	...	0.6	0.6	...	0.6	0.6

Notes: In this table, "Biomass" includes biomass, biodiesel, biogas, and municipal solid waste. "Landfill gas" includes fuel cells, landfill gas, and low emission advanced renewables. "Hydro" includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as "0.0" are greater than 0 but less than 0.05; values shown as "-" are truly zero. Capacity from gas-fired steam turbines is grouped with "Natural gas CT." Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their prime mover type.

Table 18. In-state and in-region generation detail (TWh) for Massachusetts and New England (inclusive of Massachusetts) under the alternative sales forecast

	2016	...	2018		2019		2020		...	2025		...	2030	
		...	Ref	Policy	Ref	Policy	Ref	Policy	...	Ref	Policy	...	Ref	Policy
Massachusetts	**32.8**	...	**34.6**	**33.6**	**29.6**	**29.4**	**27.5**	**27.3**	...	**23.4**	**23.5**	...	**25.3**	**25.3**
Renewable resources	**4.4**	...	**5.5**	**5.5**	**6.1**	**6.2**	**6.5**	**6.6**	...	**10.0**	**10.0**	...	**13.2**	**13.2**
Biomass	1.9	...	1.8	1.9	1.8	1.9	1.8	1.9	...	1.8	1.8	...	1.8	1.8
Hydro	0.4	...	0.5	0.5	0.6	0.6	0.6	0.6	...	0.6	0.6	...	0.6	0.6
Landfill Gas	0.3	...	0.3	0.3	0.3	0.3	0.3	0.3	...	0.3	0.3	...	0.3	0.3
Solar: Distributed	0.7	...	1.3	1.3	1.5	1.5	1.7	1.7	...	2.4	2.4	...	2.5	2.5
Solar: Utility-scale	0.8	...	1.2	1.2	1.4	1.4	1.6	1.6	...	2.0	2.0	...	1.9	1.9
Wind: Offshore	-	...	-	-	-	-	-	-	...	2.3	2.3	...	5.6	5.6
Wind: Onshore	0.3	...	0.3	0.3	0.4	0.4	0.4	0.4	...	0.5	0.5	...	0.5	0.5
Other resources	**28.3**	...	**29.1**	**28.1**	**23.5**	**23.2**	**21.0**	**20.6**	...	**13.5**	**13.5**	...	**12.1**	**12.1**
Natural gas CC	20.5	...	22.9	21.8	21.3	21.0	20.6	20.2	...	13.2	13.2	...	11.9	11.9
Natural gas CT	0.7	...	0.5	0.5	0.4	0.4	0.4	0.4	...	0.3	0.3	...	0.3	0.3
Coal	1.3	...	-	-	-	-	-	-	...	-	-	...	-	-
Nuclear	5.8	...	5.8	5.8	1.8	1.8	-	-	...	-	-	...	-	-
Battery	-	...	-	-	-	-	-	-	...	-	-	...	-	-
New England	**125.1**	...	**129.8**	**129.8**	**129.6**	**129.6**	**128.7**	**128.7**	...	**126.1**	**126.1**	...	**126.8**	**126.8**
Renewable resources	**19.5**	...	**21.4**	**22.2**	**22.3**	**24.0**	**23.4**	**25.1**	...	**28.6**	**28.6**	...	**31.7**	**31.7**
Biomass	7.8	...	6.6	7.4	6.2	7.9	6.3	8.1	...	6.1	6.1	...	6.1	6.1
Hydro	6.0	...	6.3	6.3	6.4	6.4	6.4	6.4	...	6.9	6.9	...	7.0	7.0
Landfill Gas	0.8	...	0.8	0.8	0.9	0.9	0.9	0.9	...	0.8	0.8	...	0.7	0.7
Solar: Distributed	0.9	...	1.8	1.8	2.1	2.1	2.4	2.4	...	3.2	3.2	...	3.2	3.2
Solar: Utility-scale	1.2	...	2.0	2.0	2.8	2.8	3.3	3.3	...	4.0	4.0	...	3.8	3.8
Wind: Offshore	0.0	...	0.1	0.1	0.1	0.1	0.1	0.1	...	2.4	2.4	...	5.7	5.7
Wind: Onshore	2.7	...	3.8	3.8	3.9	3.9	4.0	4.0	...	5.2	5.2	...	5.2	5.2
Other resources	**84.5**	...	**87.4**	**86.6**	**86.3**	**84.6**	**84.3**	**82.5**	...	**68.0**	**68.0**	...	**65.6**	**65.6**
Natural gas CC	48.1	...	53.3	52.6	55.8	54.1	56.9	55.3	...	39.9	39.9	...	38.5	38.5
Natural gas CT	1.1	...	0.8	0.8	0.6	0.6	0.6	0.5	...	0.4	0.4	...	0.4	0.4
Coal	2.2	...	1.1	1.1	1.0	0.9	1.4	1.2	...	0.5	0.5	...	0.2	0.2
Nuclear	33.0	...	32.2	32.2	29.0	29.0	25.5	25.5	...	27.2	27.2	...	26.4	26.4
Battery	-	...	-	-	-	-	-	-	...	-	-	...	-	-
Net Imports	**21.1**	...	**21.0**	**21.0**	**20.9**	**20.9**	**21.1**	**21.1**	...	**29.4**	**29.4**	...	**29.5**	**29.5**
New Hydro	0.0	...	0.0	0.0	0.0	0.0	0.0	0.0	...	8.5	8.5	...	8.5	8.5
Other Net Imports	21.1	...	21.0	21.0	20.9	20.9	21.1	21.1	...	20.9	20.9	...	21.0	21.0

Notes: In this table, "Biomass" includes biomass, biodiesel, biogas, and municipal solid waste. "Landfill gas" includes fuel cells, landfill gas, and low emission advanced renewables. "Hydro" includes standard hydroelectric generators, tidal power, and pumped storage (which is not eligible for RECs). Values shown as "0.0" are greater than 0 but less than 0.05; values shown as "-" are truly zero. Generation from gas-fired steam turbines is grouped with "Natural gas CT." Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their prime mover type.

Table 19. In-state and in-region fossil fuel CO_2 emissions detail for Massachusetts and New England (inclusive of Massachusetts) (million metric tons CO_2) under the alternative sales forecast

	2016	…	2018		2019		2020		…	2025		…	2030	
		…	Ref	Policy	Ref	Policy	Ref	Policy	…	Ref	Policy	…	Ref	Policy
Massachusetts	**10.1**	…	**9.7**	**9.2**	**9.0**	**8.8**	**8.7**	**8.5**	…	**5.6**	**5.6**	…	**5.1**	**5.1**
Affected resources	**9.8**	…	**9.4**	**9.0**	**8.7**	**8.6**	**8.4**	**8.3**	…	**5.4**	**5.4**	…	**4.8**	**4.8**
Natural gas CC	8.6	…	9.4	8.9	8.6	8.5	8.4	8.2	…	5.3	5.3	…	4.8	4.8
Natural gas CT	0.2	…	0.1	0.1	0.1	0.1	0.0	0.0	…	0.0	0.0	…	0.0	0.0
Coal	1.0	…	-	-	-	-	-	-	…	-	-	…	-	-
Other resources	**0.3**	…	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	…	**0.2**	**0.2**	…	**0.2**	**0.2**
Natural gas CC	0.1	…	0.1	0.1	0.1	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Natural gas CT	0.2	…	0.1	0.1	0.2	0.1	0.1	0.1	…	0.1	0.1	…	0.1	0.1
Coal	-	…	-	-	-	-	-	-	…	-	-	…	-	-
New England	**22.4**	…	**23.0**	**22.7**	**23.6**	**23.0**	**24.3**	**23.5**	…	**16.6**	**16.6**	…	**15.8**	**15.8**
Affected resources	**9.8**	…	**9.4**	**9.0**	**8.7**	**8.6**	**8.4**	**8.3**	…	**5.4**	**5.4**	…	**4.8**	**4.8**
Natural gas CC	8.6	…	9.4	8.9	8.6	8.5	8.4	8.2	…	5.3	5.3	…	4.8	4.8
Natural gas CT	0.2	…	0.1	0.1	0.1	0.1	0.0	0.0	…	0.0	0.0	…	0.0	0.0
Coal	1.0	…	-	-	-	-	-	-	…	-	-	…	-	-
Other resources	**12.6**	…	**13.6**	**13.7**	**15.0**	**14.4**	**15.9**	**15.3**	…	**11.3**	**11.3**	…	**11.0**	**11.0**
Natural gas CC	11.2	…	12.2	12.4	13.7	13.2	14.3	13.9	…	10.6	10.6	…	10.6	10.6
Natural gas CT	0.5	…	0.2	0.2	0.3	0.3	0.2	0.2	…	0.2	0.2	…	0.2	0.2
Coal	0.9	…	1.1	1.0	1.0	0.9	1.3	1.2	…	0.5	0.5	…	0.2	0.2

Note: For comparison purposes, emissions from affected resources under 310 CMR 7.74 are shown in the "Affected resources" section in the Reference Case, although the regulations were not modeled as being in effect in the Reference Case. Any resources that consume oil are grouped either with "Natural gas CC" or "Natural gas CT" depending on their primary fuel type. Emissions associated with biomass or municipal solid waste are not included in this table.