
New England's Shrinking Need for Natural Gas

An analysis of policy impacts on natural gas use
in New England's electric sector

**Prepared for the Connecticut Fund for the Environment,
Consumers for Sensible Energy, Mass Energy Consumers
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EXECUTIVE SUMMARY

This report examines the need for, and the cost of, the Access Northeast (ANE) natural gas pipeline. Pipeline proponents claim that the ANE pipeline is needed to relieve capacity constraints on New England's natural gas pipeline system and that the cost of the pipeline is justified because it will ultimately save money for New England consumers. Our findings show that any savings created by the ANE pipeline will be outweighed by its costs, which are more than twice what the proponents have generally reported. We have also determined that the need for natural gas in New England will decrease dramatically within a few years of ANE's construction, alleviating the capacity constraints cited to justify the pipeline.

The proposed ANE project would expand the existing Algonquin Gas Transmission network in New England. Through implementation and expansion of new compressor stations and pipeline looping along the existing Algonquin pipeline in Connecticut, Massachusetts, New York, and Rhode Island and construction of new pipeline laterals in Massachusetts, the pipeline would increase the capacity to transport fracked gas originating from Pennsylvania through New York to New England by 500 million cubic feet per day. In addition, the proposed ANE project would also include the construction of a new liquefied natural gas (LNG) storage facility in Acushnet, Massachusetts, which would be able to deliver an additional 400 million cubic feet of fuel per day to the natural gas system. ANE's major proponents include Spectra Energy, a pipeline developer, and Eversource and National Grid, two major utilities that make up 70 percent of all electric sales and one-third of all end-user natural gas sales in New England.¹

Our analysis and findings follow.

Over the past several years, New England's electricity system has changed significantly. Amidst the closing of nuclear and coal-fired power plants, flattening electricity sales, and additions of zero-emitting renewables, natural gas has become the dominant fuel source for New England's electric generation. At the same time, electricity prices have spiked during several recent winters, generally attributed to constraints on the pipeline system that supplies the lion's share of the region's natural gas.

Although average natural gas prices have remained low, the price spikes of previous years remain a concern. Some policymakers believe that building or expanding pipeline infrastructure throughout New England is the quickest and most obvious remedy.

Cost concerns have been magnified by the proposal to have electric ratepayers pay for new gas pipelines. Natural gas pipeline expansion is almost always paid for by natural gas ratepayers, who use

¹ ANE's proposed economic benefits were assessed in expert testimony commissioned by Eversource, available at Massachusetts Department of Public Utilities (DPU 15-181): Direct testimony of Kevin R. Petak on behalf of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy. December 18, 2015. Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2finitial_filing_part3of3_Petak_.pdf

gas for heat or industrial use. However, as proposed, the ANE pipeline relies on a novel funding mechanism whereby electric ratepayers would pay for new gas pipelines. This unprecedented funding proposal has spurred controversy and litigation: the Massachusetts Supreme Judicial Court and the New Hampshire Public Utilities Commission both rejected this approach, declaring that it violates state laws enacted to restructure the electric utility sector and to protect consumers from undue financial risk.

A number of reports on the economics and financing of new natural gas pipelines proposed for New England have appeared in recent years. However, this is the first study to take full account of all existing laws and regulations—some of which were established very recently—that will affect the future use of natural gas for electricity generation.

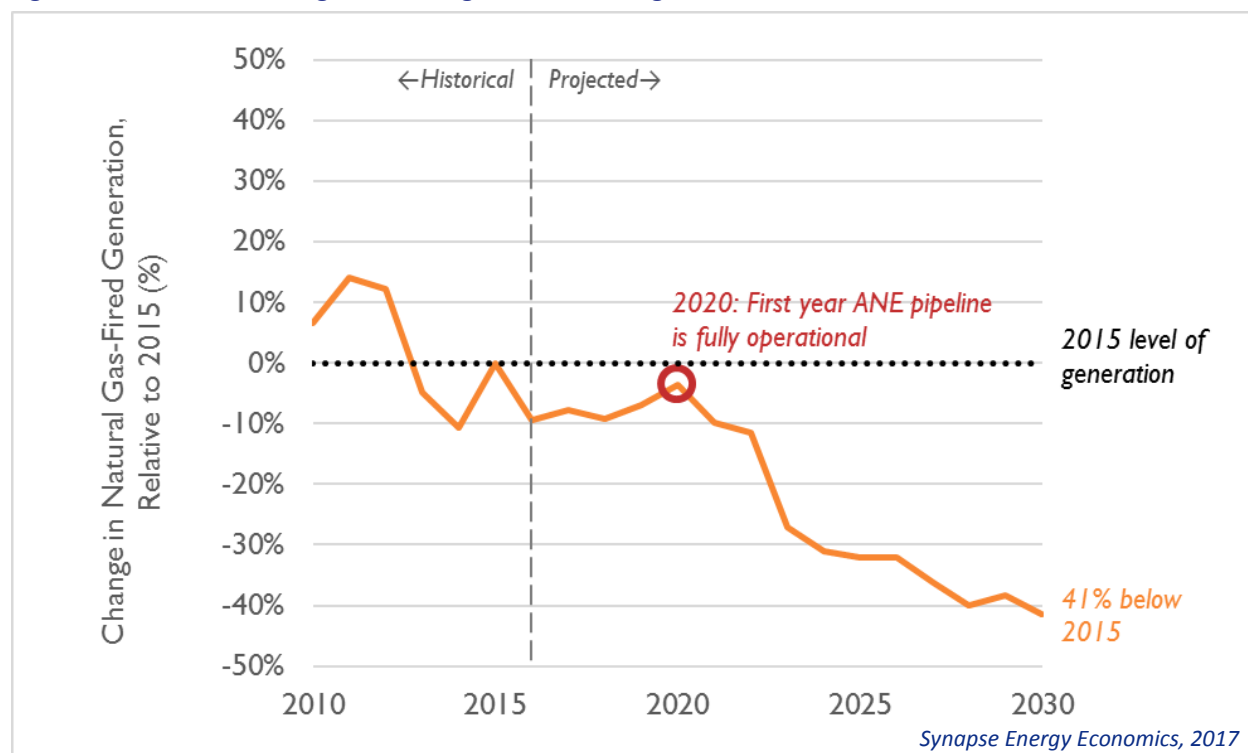
For this report, Synapse assessed the need for and the potential costs and savings of the ANE pipeline, the sole remaining proposed natural gas pipeline in the region that would rely on electric ratepayer funding. We modeled energy use, prices, and emissions in a base scenario in which there is no new pipeline (Base Case) compared to a scenario in which the ANE pipeline is constructed (Pipeline Case).

Our analysis led us to the following findings:

First, with or without a new pipeline, existing laws and regulations will cumulatively require New England’s use of natural gas for electric generation to decrease by 27 percent by 2023, relative to 2015 levels.

Natural gas use is forecasted to decline dramatically in 2023—just a few years after the ANE pipeline is supposed to be fully operational (see Figure ES-1). Existing laws—renewable portfolio standards, energy efficiency resource standards, long-term requirements for additional hydropower and wind power, and carbon dioxide (CO₂) emissions caps—require a significant reduction in natural gas-fired generation throughout New England. This decrease in overall gas use will reduce capacity constraints of existing pipelines and the need for new pipelines. By 2023, shortly after ANE’s construction, natural gas-fired generation is estimated to be 27 percent lower than in 2015. And by 2030, natural gas-fired electric generation is estimated to be 41 percent lower than in 2015.

Figure ES-1. Estimated change in natural gas-fired electric generation, relative to 2015



Second, the ANE pipeline will cost New England consumers \$6.6 billion, not \$3.2 billion as previously reported.

Proponents of ANE have publicized an expected pipeline construction cost of \$3.2 billion. However, according to expert witness testimony for Eversource, one of the main project proponents, after taking into account additional costs, including operations and maintenance, depreciation expenses, and return on equity, the ANE pipeline is expected to cost \$0.5 billion per year for 20 years—about \$6.6 billion in present value terms. The pipeline developers seek to charge these costs to electric ratepayers throughout New England.

Third, if the pipeline is built, New England ratepayers will pay additional costs of \$277 million over its lifetime.

Even if the ANE pipeline reduces constraints and gas prices, it will cause overall price increases on consumers throughout New England, due to the cost of the pipeline itself. The pipeline is expected to impose net costs of \$277 million on all New England electric ratepayers on a present-value basis.

Fourth, if the pipeline is built, electric ratepayers in Massachusetts and Connecticut will pay additional costs of \$141 million and \$85 million, respectively.

Massachusetts ratepayers will see cost increases associated with the ANE pipeline. Our analysis shows that Massachusetts electric ratepayers will pay additional costs of \$141 million over the life of the pipeline.

Connecticut ratepayers will be looking at additional costs of \$85 million over the lifetime of the pipeline. If the pipeline were built without the support of electric ratepayers in Massachusetts and New Hampshire, the costs to Connecticut ratepayers could be as high as \$1.9 billion. The Connecticut Department of Energy & Environmental Protection has stated that this approach would burden the state's ratepayers with disproportionate costs.

Fifth, implementing emission reduction mandates and targets under each New England state's global warming solutions laws will cause economy-wide natural gas use to decrease by 20 percent by 2030, despite recent policies and trends that incentivize fuel-switching to natural gas.

In recent years, as the price of natural gas has dropped compared to other fuels, many New England consumers have switched their home and business heating systems to natural gas. At the same time, some states have prioritized natural gas fuel-switching, including Connecticut as a part of its Comprehensive Energy Strategy.

However, in order to attain greenhouse gas reductions in line with the scientific consensus on averting catastrophic climate change—and to comply with state laws intended to achieve this reduction—all of the New England states will have to go even further to reduce greenhouse gas emissions. Achieving the greenhouse gas emission reduction goals of the six-state region will require economy-wide CO₂ emissions in 2030 to decrease by 40 percent, relative to 1990 levels. Additional regulations will likely be needed to reduce emissions from residential and commercial buildings, as well as from transportation and throughout industry. These policies will promote more reductions in natural gas, beyond the electric sector.

Synapse also modeled two additional scenarios (with and without the ANE pipeline) in which each New England state imposes more stringent emissions caps to comply with legal mandates or agreements under the Global Warming Solutions Act or similar legislation and targets. Even after accounting for expected fuel-switching and other load growth in the non-electric sectors, total natural gas use in these scenarios is expected to fall by 20 percent, relative to 2015. This will further reduce the need for ANE and other natural gas pipeline infrastructure.

Conclusion

Our modeling shows that if the ANE pipeline is built as proposed, ratepayers will bear substantial net cost increases on their utility bills, even if the pipeline alleviates winter price spikes. Furthermore, within several years of the pipeline's construction, the overall need for natural gas in New England's electric sector is expected to decline dramatically as states work toward compliance with existing laws and regulations. The decline in natural gas use for electric generation indicates that even existing gas

pipelines may operate under capacity and that ANE—or other new pipeline infrastructure—will not be needed to supply either electric generators or gas heating customers.²

Under these circumstances, spending \$6.6 billion on a new pipeline meant to provide natural gas year-round to electric power plants is not a reasonable or cost-effective way to address pipeline capacity constraints.

² Note that this analysis does not include the impacts of the just-completed AIM Project, or the proposed TGP-CT Expansion and Atlantic Bridge pipeline projects, and does not rely on any assumptions related to the success or failure of those proposals. As proposed, each of these projects would reduce pipeline constraints. This is likely to lower regional natural gas prices and render ANE that much less economical and less needed.



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1. UNDERSTANDING THE ISSUES

The energy industry in New England is transforming. Energy demand has flattened as a result of energy efficiency efforts. Numerous nuclear and coal-fired plants have already been taken offline or have announced their intention to close. Additions of new renewable resources such as wind and solar have accelerated and are an increasingly important part of the regional resource mix. And perhaps most controversially, natural gas as a fuel for electric generation has grown more prominent than ever.

New England stands at an energy crossroads: should it double down on natural gas infrastructure? Or should it embrace its legally-required clean energy future? These paths are mutually exclusive: reasonable alternatives to natural gas are required in order for the region to achieve its greenhouse gas emissions mandates.

1.1. Paying for new natural gas infrastructure

Over the past several years, New England's electricity system has changed significantly. Amidst the closing of nuclear and coal-fired power plants, flattening electricity sales, and additions of zero-emitting renewables, natural gas has become the dominant fuel source for New England's electric generation. At the same time, electricity prices have spiked during several recent winters, generally attributed to constraints on the pipeline system that supplies the lion's share of the region's natural gas.

Although average natural gas prices have remained low, the price spikes of previous years remain a concern. Some policymakers believe that building or expanding pipeline infrastructure throughout New England offers the quickest and most obvious remedy.

However, reliance on new pipelines could lead states such as Connecticut and Massachusetts to violate existing laws that require reductions in greenhouse gas emissions (including carbon dioxide and methane) from fossil fuel sources like natural gas. In addition to federal Clean Power Plan requirements, electric generators in New England must meet emission caps specified by the Regional Greenhouse Gas Initiative (RGGI) and by state-specific greenhouse gas reduction laws (called the Global Warming Solutions Act or "GWSA" in both Connecticut and Massachusetts). Intended to help avert catastrophic climate change, Connecticut's and Massachusetts's GWSAs require carbon dioxide (CO₂) emissions to be reduced by 80 percent by 2050, likely leaving little room for natural gas use at all.³

³ Connecticut's GWSA reduction target is relative to 2001 levels. Massachusetts's GWSA reduction target is relative to 1990 levels. Taken together, the New England states' goals and targets achieve emissions reductions of about 80 percent below 1990 levels by the year 2050. See Table 3 (below) for more information on state-specific greenhouse gas emissions reduction policies. Increasing dependence on natural gas supplied via pipeline also carries other climate and public health risks, including leakage of climate-damaging methane from pipelines, downstream climate and water impacts associated with hydraulic fracturing ("fracking"), and increased likelihood of accidents. Note that it is anticipated that New England states will

Concurrently, complementary state policies such as energy efficiency resource standards and renewable portfolio standards (RPS) increasingly result in reduced demand for polluting fuels and increased use of cleaner sources of generation. Implementation of these policies will lead to a decrease in the consumption of natural gas by the New England electric sector.

Furthermore, proposed pipeline infrastructure is costly. The Access Northeast (ANE) pipeline, the focus of this analysis, has a construction cost of \$3.2 billion, a price tag widely cited by its proponents, pipeline developer Spectra Energy and New England energy companies Eversource and National Grid.⁴ But after taking into account the full costs of the ANE pipeline, including operations and maintenance costs, depreciation expenses, and a return on equity for the developer, the pipeline could cost about \$0.5 billion per year for 20 years, or \$6.6 billion in present value terms.⁵

The cost of new pipeline infrastructure is almost always recovered from natural gas consumers (ratepayers) through increases on their gas bills. Pipeline customers pay for new pipelines when their utilities enter into long-term capacity contracts with pipeline developers. These customers include large industrial facilities and gas utilities (known as local distribution companies or LDCs) that supply gas to residential and commercial users throughout the region, who then pass along the costs of pipeline infrastructure to ratepayers. However, Eversource and National Grid have proposed a new way to finance the ANE pipeline: rather than collect the cost of the pipeline from those who use natural gas to heat their homes and businesses, they have proposed that electric utility ratepayers pay for it.⁶

This unprecedented approach to cost recovery in New England has proven to be very controversial. Despite the initial support of numerous policymakers and public utility commissions in the region, the Supreme Judicial Court in Massachusetts and the New Hampshire Public Utilities Commission ruled that this cost allocation runs counter to existing legislation in both states.

use existing regulations (such as RGGI) as means to comply with the federal Clean Power Plan, which, for the New England states, requires less stringent emissions reductions than already-existing regulations. This report uses the term “GWSA” as a shorthand for all six New England states’ emission reductions mandates and targets.

⁴ Access Northeast is proposed to expand the existing Algonquin Gas Transmission network in New England. It would increase the capacity to transport gas from New York to New England by 500 million cubic feet per day through additions of new compressor stations and pipeline looping along the existing Algonquin pipeline in Connecticut, Massachusetts, New York, and Rhode Island, as well as the construction of new pipeline laterals in Massachusetts. The project would also include the construction of a new liquefied natural gas (LNG) storage facility in Acushnet, Massachusetts. This facility would have a total volume of 6.8 billion cubic feet and would be able to deliver an additional 400 million cubic feet of fuel per day to the natural gas system. The Access Northeast project is sponsored by Spectra Energy (with an ownership share of 40 percent), Eversource Energy (40 percent), and National Grid (20 percent). Note that \$3.2 billion is the current expected cost of the pipeline project, and may be revised in the future. More information on Access Northeast available at <http://www.accessnortheastenergy.com/FAQs/About-Access-Northeast/>

⁵ Massachusetts Department of Public Utilities (DPU 15-181): Direct testimony of Kevin R. Petak on behalf of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy. December 18, 2015. Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2Finitial_filing_part3of3_Petak_.pdf

⁶ This analysis does not include any assessment of revenues that could result from exports of natural gas to other regions.

In the wake of these decisions, state agencies in Connecticut and Rhode Island have pulled back their support for the project as proposed.⁷ However, unlike in Massachusetts and New Hampshire, no determination has been made in either state that the proposed financing scheme is unlawful. Table 1 summarizes the expected costs of the pipeline in a scenario in which all New England electric ratepayers pay for the pipeline (Six-State) and in a scenario in which only the four states that have not explicitly disallowed the pipeline pay for it (Four-State).⁸

Table 1. Share of electric sales, annualized gross pipeline cost, and 20-year present value at a 5 percent discount rate. All values are in real 2015 million dollars.

	Share of Sales		Annualized Cost		Net Present Value	
	<i>Six-State</i>	<i>Four-State</i>	<i>Six-State</i>	<i>Four-State</i>	<i>Six-State</i>	<i>Four-State</i>
CT	25%	54%	\$129	\$284	\$1,608	\$3,542
MA	45%	-	\$239	-	\$2,980	-
ME	10%	22%	\$52	\$115	\$648	\$1,429
NH	9%	-	\$48	-	\$600	-
RI	6%	14%	\$34	\$74	\$418	\$921
VT	5%	10%	\$24	\$53	\$301	\$663
Total	100%	100%	\$526	\$526	\$6,555	\$6,555

1.2. Examining the potential costs

Many studies have been written on the potential benefits of the pipelines. Some have examined the Access Northeast project specifically, while others have investigated other projects or generic, hypothetical new pipelines.⁹ Some studies have examined the “need” for a pipeline (from a reliability standpoint) while others have assessed the costs and benefits of a new pipeline relative to either doing nothing or implementing pipeline alternatives.

All previous studies share the same critical drawbacks: none measure the impact of the most recent changes to policies on energy efficiency, renewable portfolio standards, and greenhouse gas regulations in New England states, and none take into account the most recent information on natural gas, renewable, and energy efficiency prices.

⁷ See Massachusetts Department of Public Utilities v. Engie Gas & LNG LLC. SJC-12051, SJC-12052. 475 Mass. 191; 56 N.E.3d 740; LEXIS 603 (2016) and http://www.puc.state.nh.us/regulatory/Docketbk/2016/16-241/ORDERS/16-241_2016-10-06_ORDER_25950.PDF.

⁸ Of these six states, Vermont is the only state in which there has not been a formal process examining this type of cost allocation for pipeline expansion. However, analysis by the pipeline proponents indicate that ANE costs are assumed to be allocated across all New England ratepayers (Petak et al.).

⁹ See Appendix D for a literature review of pipeline studies.

This report will shed light on the following questions, based on up-to-date information:

1. Will the construction of the ANE pipeline decrease or increase costs to consumers?
2. How will existing laws and regulations impact natural gas-fired electricity generation in the future?
3. What will happen to natural gas-fired generation when future policies are implemented to curtail New England greenhouse gas emissions to comply with each state's global warming solutions legislation?

2. THE NEW ENGLAND BACKDROP

To answer these questions, it is important to understand the energy systems of the six New England states. This section describes the current and future dynamics of New England's electric and natural gas systems. As the developers of the Access Northeast pipeline have proposed that it should be paid for by electric ratepayers, instead of gas customers, this study focuses on the impact of the Access Northeast pipeline on the electric sector. And because the New England electric system is so tightly interconnected (as described below), we examine the regional impacts of the pipeline.

2.1. New England's electric system

The six New England states operate as a single electricity system. Electric utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont work together in a single power pool managed by the New England Independent System Operator (ISO-NE). ISO-NE coordinates the dispatch of power plants to ensure reliable electricity is provided to all New England ratepayers. ISO-NE also oversees long-term planning to ensure that adequate generating capacity and transmission infrastructure is constructed for the future. Most of the electricity consumed in New England is generated in-region, with 5-15 percent imported from New York and Canada.

Compared to most other regions across the country, New England has become uniquely reliant on natural gas for electricity generation. In 2015, more than half of in-region electricity generation was supplied through natural gas, with just 4 percent of generation coming from coal-fired power plants (see Table 2).¹⁰ The remaining 45 percent of in-region generation came from non-emitting renewable, hydroelectric, and nuclear power sources. These resources are often referred to as "must-take" because they have very low marginal generation costs or have operational constraints that do not allow them to

¹⁰ Historically, over 25 percent of New England's electricity was powered by burning petroleum. Since 2000, this type of generation has dwindled to just 2 percent of total generation. Today, petroleum is largely used at natural gas-fired power plants that switch to petroleum only when faced with price spikes at times of peak demand. Given this, we have included petroleum consumed for electricity-generating purposes in with the "natural gas" category throughout this report, except where noted.

quickly respond to changes in electricity demand from consumers.

Accordingly, when renewable or non-emitting energy sources increase in future years (as a result of mandated reductions in emissions, increases in renewable portfolio standards, or long-term contracting requirements for off-shore wind and imports, for example) or when sales decrease as a result of energy efficiency, natural gas use will decrease, since it is the only resource available to be displaced.¹¹

Table 2. Distribution of New England’s in-region generation, 2015

Resource	Natural Gas	Nuclear	Renewables	Hydro	Coal
Share	51%	29%	11%	6%	4%

Note: In this table and elsewhere in this document, “Renewables” includes wind, solar, biomass, and landfill gas (i.e., resources that can fulfill the “Class I” requirement under each New England state’s renewable portfolio standard).

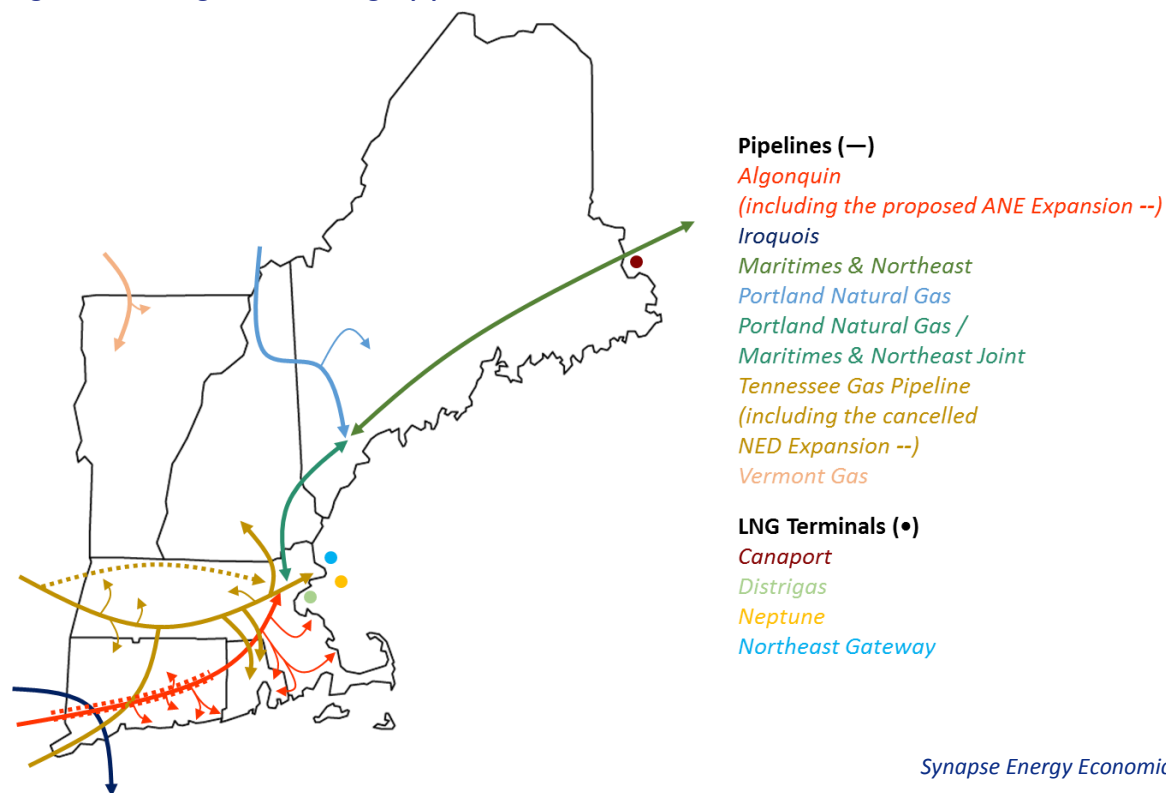
2.2. New England’s natural gas system

The New England states also share an interconnected natural gas pipeline and distribution system, which overlaps and connects with the electric system (see Figure 1). Unlike electricity, all of the natural gas used in New England is imported from other states, Canada, or via liquefied natural gas (LNG) delivered to a handful of sites. Large transmission pipelines pump natural gas into the region where it is then delivered to end-use customers through smaller pipeline distribution systems, sent to power plants via pipeline laterals, or stored as LNG in storage facilities until needed.

Unlike the electric system, New England’s natural gas system does not have a coordinating agency. Nearly 100 electric generators, 50 gas utilities (that deliver natural gas to residential and commercial consumers), and numerous industrial facilities purchase fuel from New England’s many natural gas suppliers without any coordinated planning. Gas utilities and industrial facilities tend to reserve natural gas from pipeline owners through long-term “firm” contracts, whereas most electricity generators purchase available natural gas on the spot market. This leaves electric generators particularly vulnerable to supply constraints and price fluctuations, especially during cold winter days when demand for natural gas for both heating and electricity is very high. Spikes in natural gas prices are paid for by those purchasing on the spot market and then passed through as higher electric prices, causing the cost of electricity to increase for consumers during these periods of high demand.

¹¹ Note that this is a simplification of the electric system. Synapse’s modeling uses forecasted price modeling and operational dynamics to estimate what resources will be displaced in future years as more renewables come online.

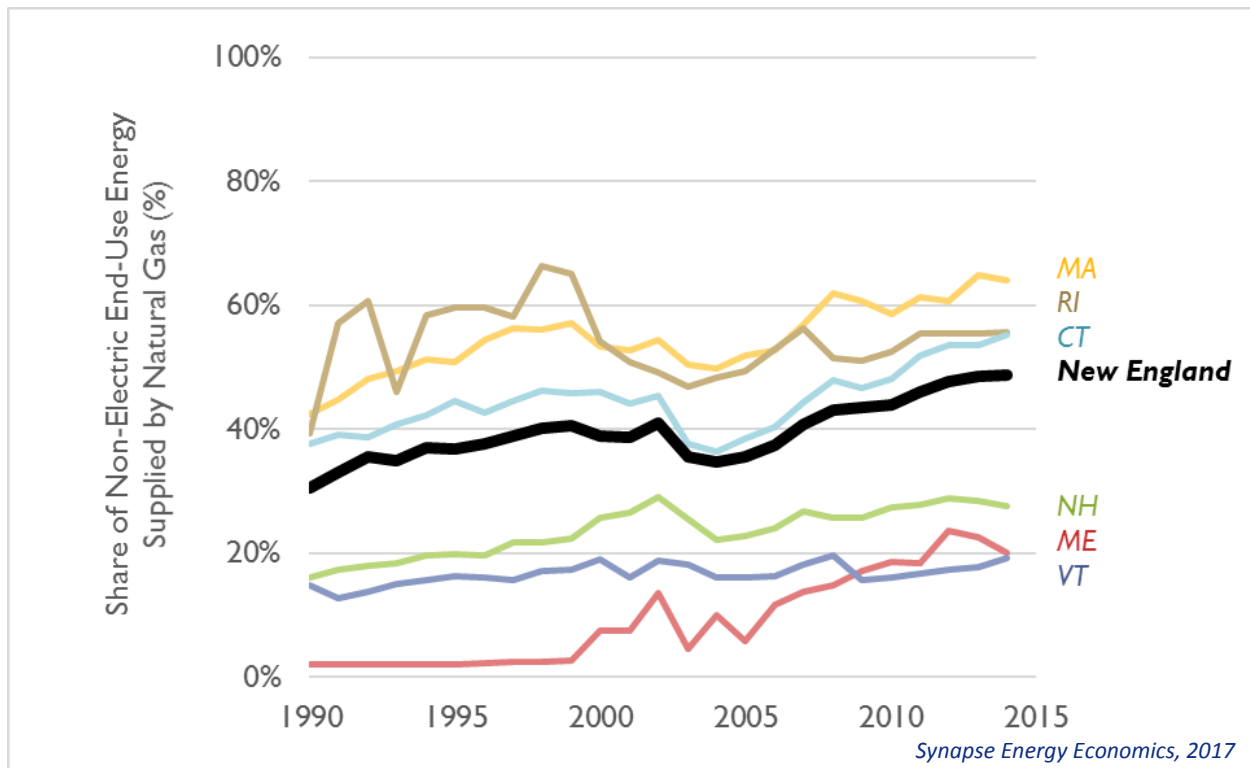
Figure 1. New England's natural gas pipeline infrastructure



Of the total amount of natural gas consumed in New England, 40-50 percent is used to power electric generators. Natural gas is also used by consumers in the residential, commercial, and industrial sectors for space, water, and industrial processes. Both non-electric energy and electricity-generating needs have increasingly been met by expanded reliance on natural gas rather than other fuels. Indeed, a key component of Connecticut's 2013 Comprehensive Energy Strategy is to encourage the conversion of end-use heating systems from oil to natural gas.¹² As of 2014, both Connecticut and Rhode Island used natural gas to provide 55 percent of the energy used for heating, while Massachusetts led New England, supplying 64 percent of all end-use energy needs with natural gas (see Figure 2).

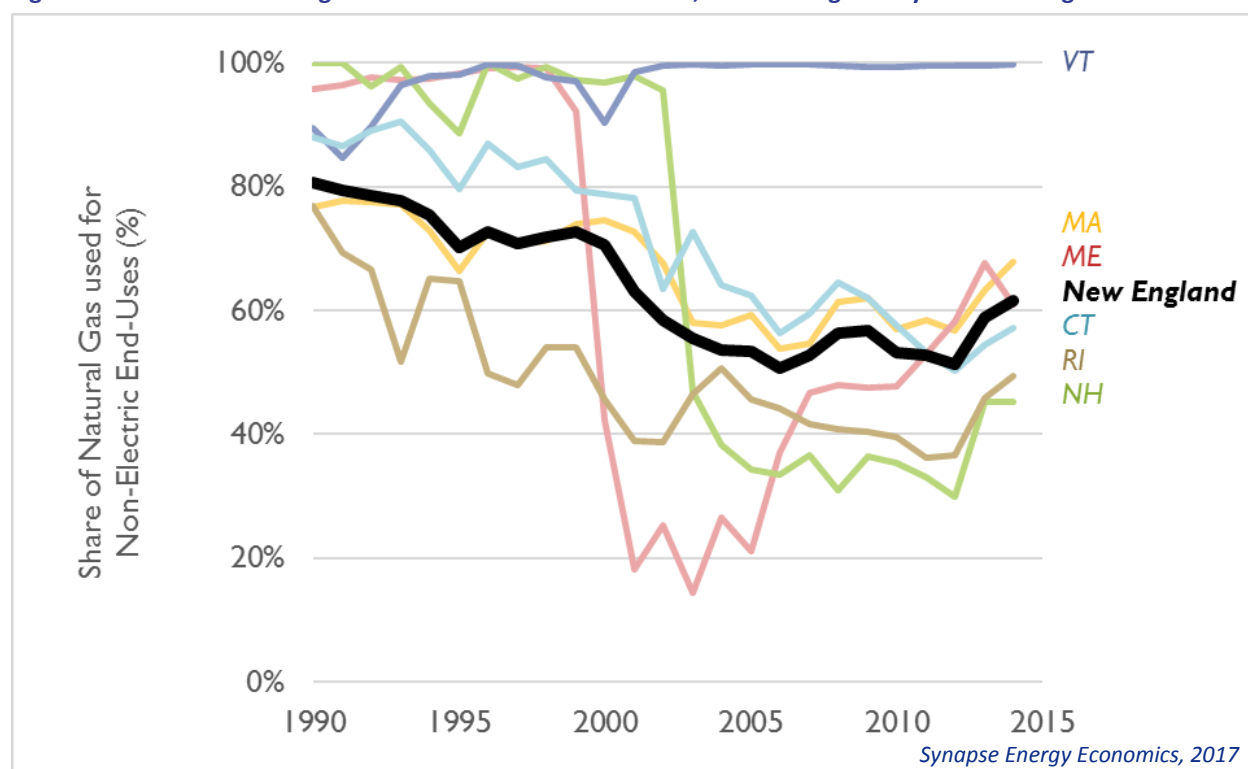
¹² The 2013 Comprehensive Energy Strategy can be found at http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf. A 2016 update to the Comprehensive Energy Strategy is expected to be released in March 2016. Policymakers in other New England states have expressed interest in encouraging oil-to-gas fuel switching, although Connecticut is the only one to have made it official state policy.

Figure 2. Percent of end-use energy fueled through natural gas for New England, by state and regional total



Traditionally, new natural gas pipeline construction has been paid for by gas ratepayers in the residential, commercial, and industrial sectors (see Figure 3). Although the percentage of natural gas used for non-electric end uses has decreased from levels of 70-80 percent in the 1990s, non-electric natural gas use still represents the majority of all natural gas use in New England.

Figure 3. Percent of natural gas used for non-electric end uses, for New England by state and regional total



2.3. Laws and regulations changing electric sector emissions

New England’s energy systems are becoming more interconnected, and the use of natural gas to produce electricity in the region has grown. At the same time, a number of laws and regulations have been enacted that will affect the demand for electricity, the resource mix used to meet that demand, and the relative economics of those resources.

Even though none of these laws and regulations are explicitly directed at reducing natural gas consumption, they will contribute to reducing the maximum amount of gas that can be used for electricity generation and other purposes in New England. The following section details the policies most likely to reduce natural gas as a fuel source for electricity generation in the future. Each law or regulation affects either (a) the total amount of electricity sales or (b) the type of resources that can be used to generate electricity. Because of the interconnectedness of the New England electric system, even laws and regulations that appear to pertain to one state will have repercussions on generators located in other states. In addition, because natural gas is the principal New England resource remaining that is not “must-take,” each of these laws and regulations will likely cause displacement of natural gas-fired electricity generation.

First, New England states continue to lead the nation in implementing cost-effective energy efficiency. Utilities in Massachusetts and Rhode Island are legally mandated to procure all available cost-effective energy efficiency under each states’ global warming solutions act. Vermont and Connecticut require energy efficiency measures to be implemented as part of energy efficiency standards or renewable

portfolio standard legislation. New Hampshire has a standalone requirement with specific mandates for sales reductions and Maine created a third-party organization, Efficiency Maine Trust, to develop triennial plans to implement cost-effective energy efficiency.

As a result of these laws and programs, New England states have emerged as leaders in implementing energy efficiency measures. Massachusetts has been first in the nation on the Energy Efficiency scorecard published by the American Council for an Energy-Efficient Economy (ACEEE) every year from 2011 to 2016.¹³ On the most recent ACEEE scorecard, Connecticut, Rhode Island, and Vermont also earned places in the top five performing states, while Maine received recognition as a “most improved” state.

Utilities and other program administrators in each New England state have filed plans indicating that they expect to continue achieving these high levels of annual energy savings into the future. As more and more energy efficiency measures are implemented, electricity sales are expected to remain flat or even decrease. In its most recent forecast, ISO-NE projects that electricity sales throughout New England will actually decrease by 0.13 percent per year from 2016 to 2025, once energy efficiency is taken into account.¹⁴ As electricity sales flatten or decline, less natural gas will be needed to supply electricity generation.

Second, as of 2016, all New England states have instituted requirements that mandate electricity utilities in all six states to procure a prescribed percentage of their electricity sales from renewables in future years. These laws—known as renewable portfolio standards (RPS)—will require the amount of generation procured from renewables for the region to reach 20–25 percent by 2030. Some of these policies, like those in Rhode Island and Vermont, were updated or instated in 2016 and have not been modeled in prior analyses of natural gas pipeline needs or benefits.¹⁵ As these new renewables come online, they will displace the need for natural gas-fired generation throughout New England.

Third, in August 2016, Governor Charlie Baker signed legislation requiring Massachusetts utilities to procure 9.45 terawatt-hours (TWh) of new imports of electricity by December 31, 2022.¹⁶ These imports may be made up of hydroelectricity alone or a combination of hydroelectricity and other renewables.

In a related action, in December 2016 the Massachusetts Department of Environmental Protection (MA DEP) promulgated new regulations under the Massachusetts Global Warming Solutions Act.¹⁷ These

¹³ The 2016 ACEEE Scorecard is available at <http://aceee.org/state-policy/scorecard>

¹⁴ The 2016 CELT forecast is available at https://www.iso-ne.com/static-assets/documents/2016/04/ison_e_fcst_data_2016.xls

¹⁵ Unlike many regions around the country, the New England states have achieved remarkable congruity in their RPS programs: for the most part, these programs allow the same types of resources to qualify as “renewable” and allow any renewable resources within New England (and adjoining electricity regions in New York and Canada) to supply renewable credits to each of the six states.

¹⁶ The final energy bill can be read at <https://malegislature.gov/Bills/189/House/H4568>

¹⁷ The MA DEP regulations can be read at <http://www.mass.gov/eea/agencies/massdep/air/climate/section3d-comments.html>

regulations incentivize the construction and eventual operation of these new sources of non-emitting generation through the establishment of a Clean Energy Standard. Although these imports will be delivered to Massachusetts, the regional nature of the New England electricity grid means that increased imports will reduce generation from natural gas generators throughout New England.

Fourth, carbon emission caps apply to all New England natural gas generators under the Regional Greenhouse Gas Initiative (RGGI). All six New England states have been part of the RGGI program since it was founded in 2008, along with Delaware, Maryland, and New York. The RGGI program guarantees that the region as a whole will reduce CO₂ emissions in the future.

The six New England states are allocated an emissions budget of 22.2 million short tons by 2020, a reduction from 43.3 million short tons at the start of the RGGI program in 2008.¹⁸ The RGGI members are currently participating in a comprehensive 2016 program review, an outcome of which may be a more stringent emissions cap in 2020 and beyond.¹⁹ As states reduce their CO₂ emissions, and as natural gas remains the primary displaceable resource that can be affected by CO₂ emissions caps, the RGGI program will lead to decreased natural gas-fired generation in the future.

Fifth, tighter CO₂ emission caps have recently been proposed for Massachusetts electric generators. These new rules will decrease total in-state CO₂ emissions from electricity generation from 12.3 million tons in 2015 to 9.6 million tons in 2020, to 2.0 million tons in 2050. These emission caps apply only to fossil fuel-fired generators in Massachusetts and, by the time they take effect, all fossil fuel-burning plants in the state will be burning natural gas. As such, this measure ensures that Massachusetts' in-state natural gas-fired electric generation will decrease by about 20 percent by 2020 and about 80 percent by 2050, relative to recent historical levels.

Finally, each state in New England has issued goals or requirements to reduce CO₂ emissions in the future. These GWSA requirements coalesce at levels that require all-sector emission reductions of about 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 (see Table 1).²⁰ To achieve these emissions reductions, all six states will need to implement policies that lead to even deeper emissions reductions beyond the results of the policies discussed above (including Massachusetts, with its December 2016 MA DEP regulations).²¹ These as-yet-to-be promulgated policies

¹⁸ A "short ton" is equal to 2,000 lbs. Short tons are in common use in American policy-making, including in RGGI. They are smaller than a metric ton, which is equal to 1,000 kilograms or about 1.1 short tons. Throughout this document, we use the term "ton" as an abbreviation for "short ton".

¹⁹ Information on RGGI's 2016 Program Review can be found at <https://www.rggi.org/design/2016-program-review>

²⁰ Synapse conducted analysis of the RGGI opportunity for further emission reductions in a March 2016 report, available at http://www.synapse-energy.com/sites/default/files/RGGI_Opportunity_2.0.pdf

²¹ Other ongoing policies include the "Clean Energy RFP", wherein the states of Massachusetts, Rhode Island, and Connecticut issued an RFP in late 2015 for resources that could "enable parties in each state to achieve their respective state's clean energy goals more cost effectively" than if each state acted alone. In October of 2016, the states collectively selected approximately 460 MW of clean energy resources, consisting of a mix of wind and solar power. These resources will be procured under long-term contracts with the local EDCs in the three states. More information on the RFP process and the

will necessitate emission reductions from other sectors, including reductions of emissions from transportation, residential and commercial buildings, and industry, but will also likely require more stringent emission caps in the electricity generation sector, further reducing the maximum allowable level of natural gas use.

Table 3. State greenhouse gas emission reduction targets, 2030 and 2050

State	2030 Target	2050 Target	Sources
Connecticut	35-45% below 1990	80% below 2001	2030: Conf. of New England Govs. Resolution 39-1 2050: C.G.S. 22a-200a (enacted by H.B. 5600) (https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm)
Maine	35-45% below 1990	75-80% below 2003	2030: Conf. of New England Govs. Resolution 39-1 “Long-term” target; date not specified: Maine Rev. Stat. ch. 3-A §576(3) (enacted by PC 2003, C. 237) (http://legislature.maine.gov/statutes/38/title38sec576.html)
Massachusetts	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 2050: Mass.Gen.L. ch. 21N §3(b) (https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3)
New Hampshire	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 2050: 2009 New Hampshire Climate Action Plan (http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/documents/nhcap_final.pdf)
Rhode Island	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 2050: Resilient Rhode Island Act of 2014, Sec. 42-6.2-2 (http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2-2.HTM)
Vermont	35-45% below 1990	75% below 1990	2030: Conf. of New England Govs. Resolution 39-1 2050: 10 V.S.A. § 578 (enacted by S. 259) (http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT168.HTM)

None of these laws and regulations directly pose a restriction on the amount of electricity that can be generated using natural gas. Instead, these policies incentivize lower levels of sales, require that some percentage of generation be produced from non-emitting sources, or impose a limit on CO₂ emissions, a byproduct of generating electricity using natural gas. When taken together, these laws and regulations have a significant impact on New England’s future electric sector. Figure 4 shows a hypothetical future in which these policies are in place; the accompanying Table 4 provides additional detail.

resources procured can be found at <https://cleanenergyrfpdotcom.files.wordpress.com/2015/11/clean-energy-rfp-final-111215.pdf> and <https://cleanenergyrfp.com/2016/10/25/bidders-selected-for-contract-negotiation/>

Figure 4. Energy sources in New England's electric sector in 2015 and hypothetical 2030 scenarios

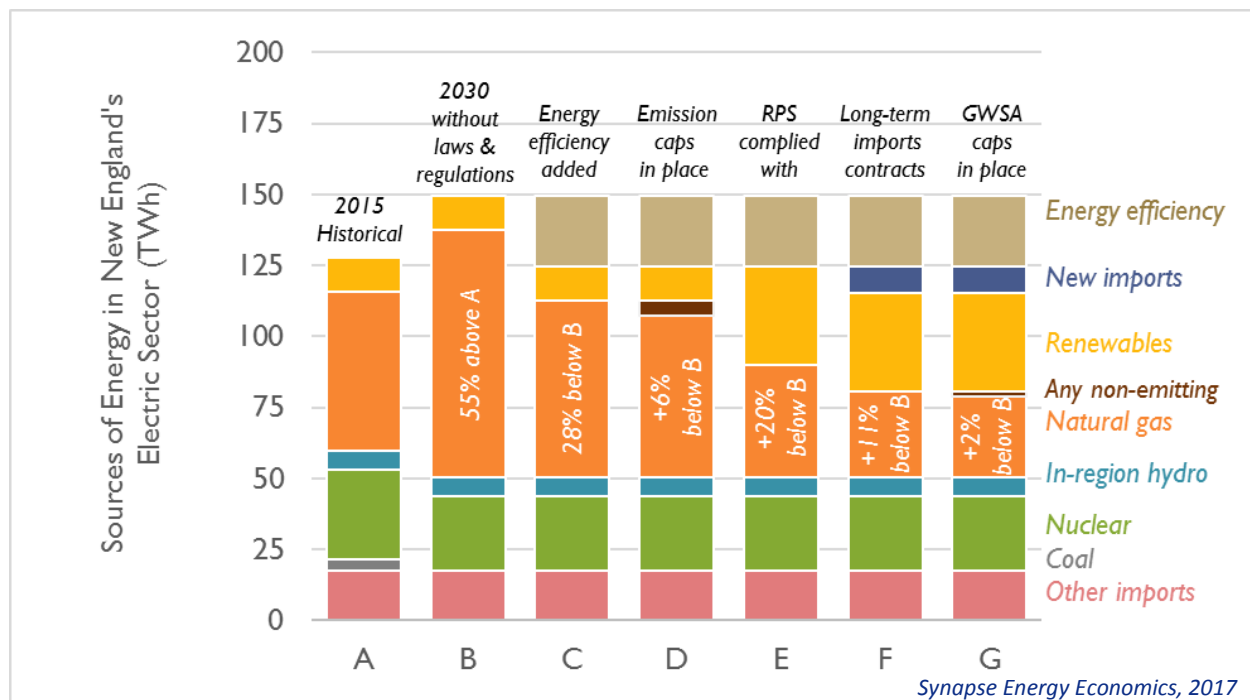


Table 4. Description of impacts on natural gas generation, as diagrammed in Figure 4

Figure 4 Column	Year	Description of change	Impact on natural gas, relative to A	Impact on natural gas, relative to B
A	2015	Actual 2015 energy	-	-
B	2030	Hypothetical 2030 future without existing policies. All coal has been retired in favor of less-expensive natural gas generation and the 2015 level of renewables continue to exist. Imports remain constant and Pilgrim nuclear plant retires.	Maximum amount of natural gas; increases by 55%	-
C	2030	Energy efficiency is added at expected levels and displaces natural gas	-	Reduces by 28%
D	2030	Emission caps from RGGI and MA DEP, restricting CO ₂ emissions and restricting natural gas-fired generation. This creates a need for more non-emitting generation (e.g., yet more energy efficiency, renewables, or additional imports)	-	Reduces by another 6% (35% total)
E	2030	Renewables are added to meet the New England states' required RPS laws of 25% of sales to be met through wind, solar, and other non-emitting sources. These new renewables displace natural gas	Reduces by 30%	Reduces by another 20% (55% total)
F	2030	As with the RPS, Massachusetts' requirement for long-term contracts for imports displaces natural gas	Reduces by 17% (47% total)	Reduces by another 11% (66% total)
G	2030	Further policies are created to ensure the New England states are meeting an emissions reduction of 40% below 1990 levels. Like RGGI and the MA DEP regulations, these new policies limit CO ₂ , and as a result, the amount of electricity that can be produced with natural gas	Reduces by 3% (49% total)	Reduces by another 2% (68% total)

Altogether, existing policies reduce the level of natural gas-fired generation that would otherwise be expected in 2030 by 66 percent. With the addition of the forthcoming unspecified GWSA regulations, 2030 natural gas generation is estimated to decrease by 68 percent. Relative to 2015 levels, the use of natural gas in the electric sector is expected to diminish by almost 50 percent by 2030.

However, this is only an estimate. In reality, these existing policies will play off of each other in varied and complex ways. For example, imposing an emissions cap on fossil fuels provides an economic incentive for non-emitting renewables. Contracting for non-emitting imports makes it easier to comply with the emissions caps. And, it is unknown whether natural gas will wholly displace coal in the future. Sophisticated electric-sector modeling—as used in this analysis with the EnCompass model—can give more accurate estimates of the impact of these complicated resource interplays, along with transmission constraints and changing prices of coal, natural gas, and renewables. Modeling programs like EnCompass can also capture how the electric system changes monthly or hourly, rather than just reflecting annual trends.

3. MODELING FINDINGS

To investigate the value of proposed pipeline infrastructure and the future demand for natural gas, Synapse used two models: EnCompass and the Multi-Sector Emissions Model (M-SEM). EnCompass is a state-of-the-art capacity expansion and production cost model. M-SEM is a spreadsheet-based model developed by Synapse to assess historical and projected energy use and emissions outside of the electric sector.²² Using these two models, we analyzed two scenarios:

- **The Base Case:** A future in which no new policies are enacted and no new pipeline infrastructure is constructed. The Base Case includes all laws and regulations established as of December 2016.
- **The Pipeline Case:** A modification of the Base Case that assumes that the ANE pipeline is constructed and that it alleviates natural gas pipeline constraints into New England in winter months, resulting in lower natural gas prices.

We also modeled two additional scenarios, on the basis of deeper future emissions cuts. These scenarios modify the Base Case and the Pipeline Case, examining what happens to natural gas when New England states impose more stringent emissions caps to meet Global Warming Solutions Act and related mandated emissions reductions. These additional restrictions would require further reductions in CO₂ emissions from all sectors.

- **GWSA-Compliant Case (Without Pipeline):** In this modification of the Base Case, we assume that New England states meet their emission reduction targets under GWSA,

²² See Appendix A for more information on the use of these models.

which coalesce at a level of 40 percent below 1990 levels by 2030. This scenario assumes the ANE pipeline is not built.

- **GWSA-Compliant Case (With Pipeline):** In this modification of the Pipeline Case, we assume that the New England states meet their GWSA emission reductions targets and that the ANE pipeline is built.

Table 5 presents a matrix of the assumptions for each scenario. Additional details regarding the models used in this analysis, modeled scenarios, and model inputs are available in Appendix A, Appendix B, and Appendix C.

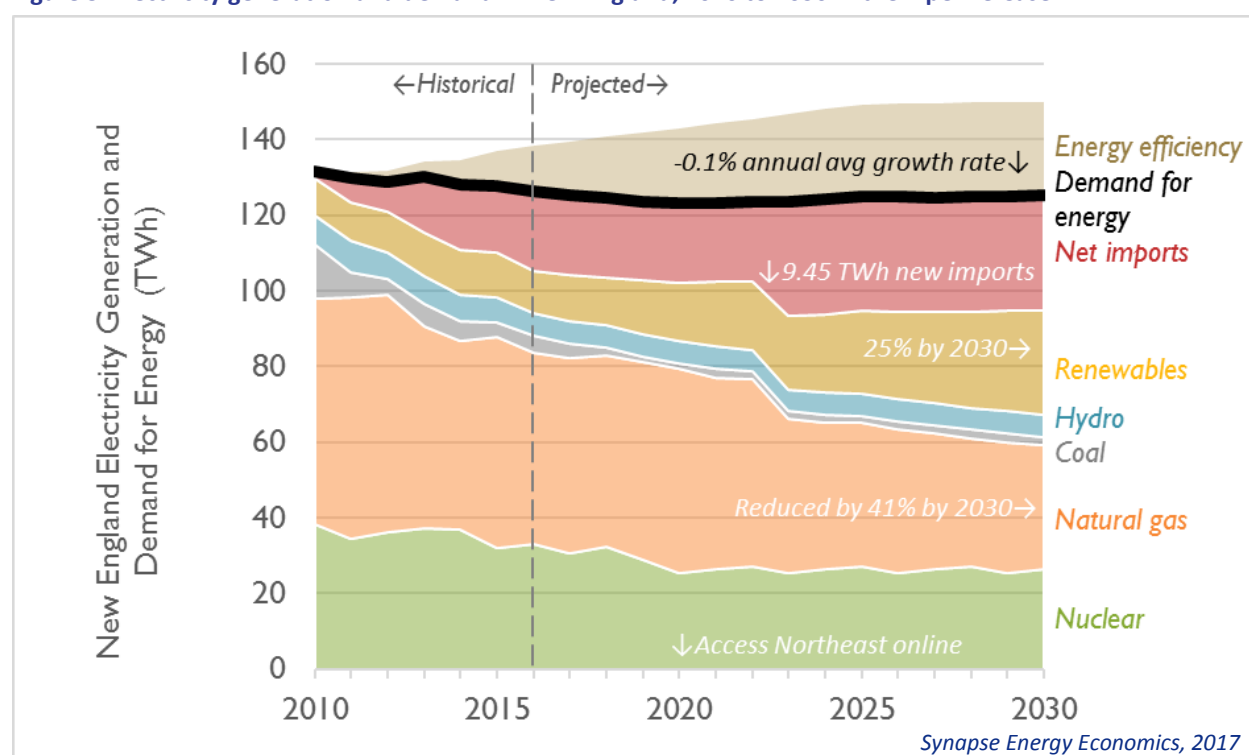
Table 5. Matrix of analyzed scenarios

	Base Case	Pipeline Case	GWSA-Compliant Case (Without Pipeline)	GWSA-Compliant Case (With Pipeline)
All known, existing policies complied with?	Yes	Yes	Yes	Yes
Access Northeast Pipeline built?	No	Yes	No	Yes
Global warming solutions targets met?	No	No	Yes	Yes

3.1. Natural gas-fired generation will decrease, with or without a new pipeline

As a result of the laws and regulations discussed above, natural gas as fuel for electric generation in New England is projected to substantially decrease with or without a pipeline. Figure 5 shows historical and projected electricity generation in New England in the Pipeline Case, along with key information on policies and model outputs. Year-to-year generation in the Base Case and Pipeline Case is essentially identical. Relative to the Base Case, the Pipeline Case features an increase in natural gas-fired generation of 0.1 TWh over 2019 to 2030—a relative increase of just 0.3 percent. This increase in natural gas-fired generation displaces more-expensive coal-fired generation, which decreases by 0.1 TWh. Because of constraints on emissions and new policies requiring increased renewables and long-term contracts for imported electricity, the price effects of constructing a new pipeline drive only a small increase in the amount of natural gas-fired generation.

Figure 5. Electricity generation and demand in New England, 2010 to 2030 in the Pipeline Case

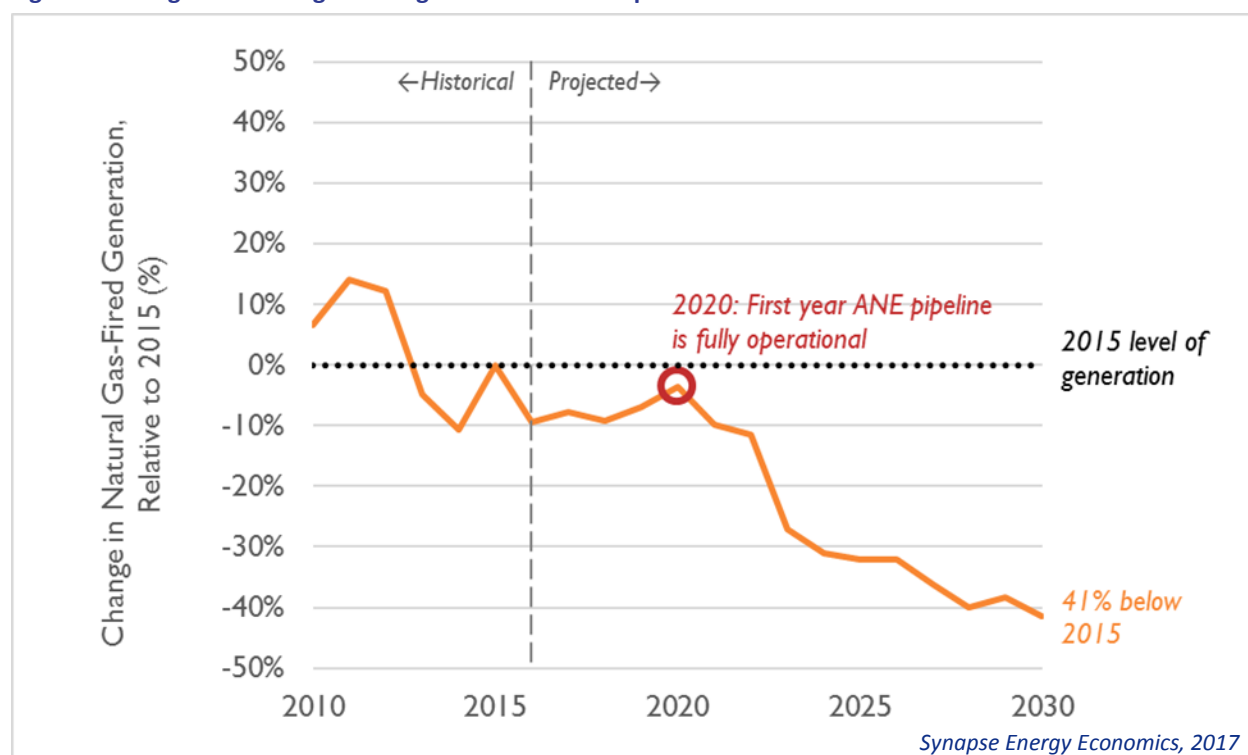


Note: 2010 through 2015 are historical data; 2016 through 2030 are modeled years. In this figure, “Renewables” includes wind, solar, biomass, and landfill gas. “Hydro” includes in-region hydroelectric plants. “Natural gas” includes both natural gas and petroleum use by generating units typically using natural gas. “Net imports” refers to the electricity imported over existing transmission lines from Canada and New York as well as new long-term contracts for imported renewable electricity.

Because of current laws and regulations, the amount of natural gas used to generate electricity in New England will decrease significantly in the future (see Figure 6). After 9.45 TWh of new, imported renewables come online at the end of 2022, we estimate that natural gas-fired generation will decrease by 27 percent, relative to 2015 levels.²³ Because of additional renewables, natural gas-fired generation is expected to decrease by 41 percent in 2030, relative to 2015 levels.

²³ Under the 2016 Massachusetts energy law, Massachusetts utilities are required to procure 9.45 TWh from either new Class I renewables (e.g., wind and solar) or from hydroelectricity. In this analysis, we modeled a resource with hydroelectric generator attributes, although a resource modeled as a combination of wind, solar, and hydroelectricity would likely displace a similar amount of natural gas in future years.

Figure 6. Change in natural gas-fired generation in the Pipeline Case



3.2. The Access Northeast pipeline project increases system costs

Because electric-sector natural gas consumption is relatively constant across the two scenarios, there are only two main differences in costs between the Base Case and the Pipeline Case:

1. Because we assume the Access Northeast pipeline alleviates wintertime constraints on natural gas traveling west-to-east via pipelines, natural gas prices are lowered in the winter months. This leads to an overall decrease in wholesale electricity costs in the Pipeline Case.
2. Because the pipeline must be paid for by electric ratepayers, the Pipeline Case features an additional cost of about \$0.5 billion per year not present in the Base Case.

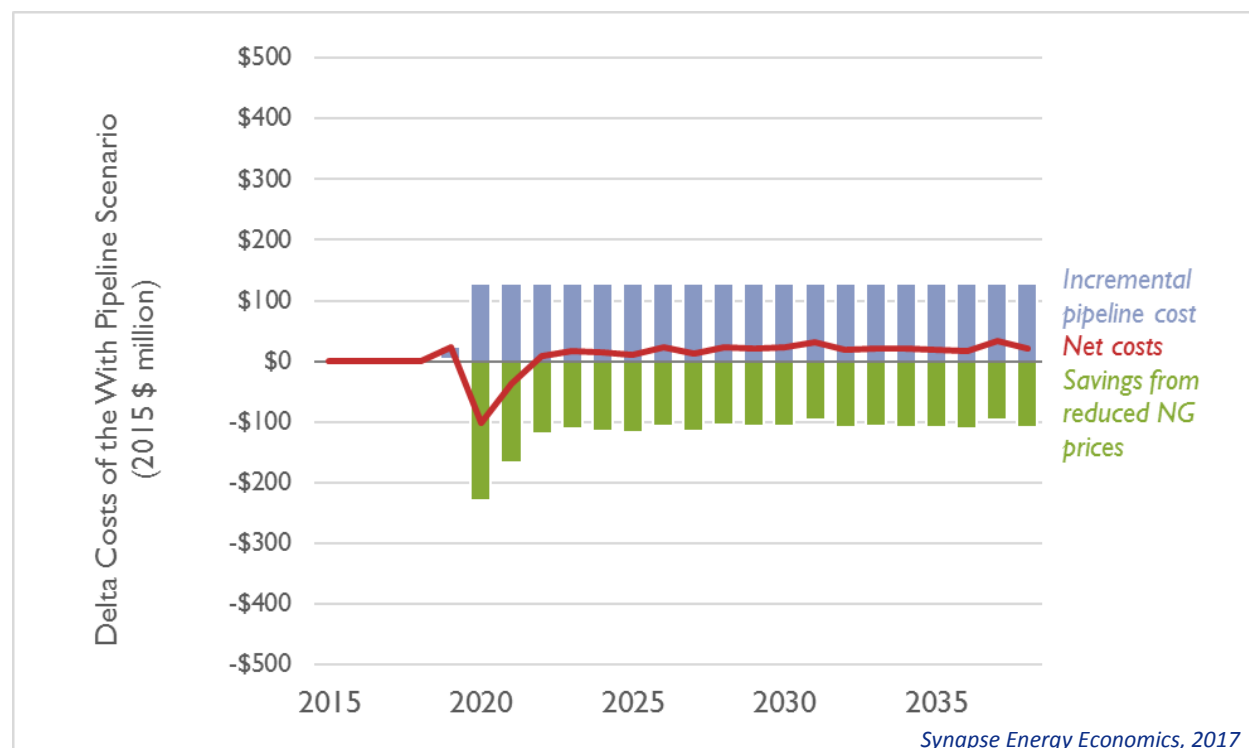
Otherwise, both the Base Case and the Pipeline Case make the same assumptions in terms of electric sales, renewable energy and energy efficiency policies, long-term contracting requirements for imported electricity, and greenhouse gas emission requirements, including both RGGI and recently-released CO₂ regulations for Massachusetts generators.²⁴

²⁴ See Appendix B for more information on input assumptions.

Financial impact of ANE pipeline on Connecticut ratepayers

We find that the reduction in wholesale electricity prices is not enough to offset the cost increases associated with building and operating the ANE pipeline (see Figure 7).²⁵ From 2019 through 2038 (the financial lifetime of the pipeline), the net present value costs of constructing a pipeline are estimated to be \$85 million for Connecticut ratepayers.²⁶

Figure 7. Costs, savings, and net costs to Connecticut of the Pipeline Case, relative to the Base Case, six-state allocation



Note: Values are shown for the “six-state allocation,” described below.

All of the pipeline’s net economic benefits occur in 2020 and 2021, when the zero-emitting Pilgrim nuclear plant is planned to retire and the region-wide RGGI cap reaches its most stringent level. When these two events overlap, the region has both high demand for replacement generation and increased competition for RGGI allowances. As a result, the wholesale market price, driven to a large degree by the price of natural gas-fired generation, increases.

This trend occurs in both the Base Case and the Pipeline Case, although the lower prices for natural gas in the Pipeline Case help to reduce this price impact. In all years after 2021, pipeline costs outweigh pipeline savings. Since price benefits occur for only two years, a long-term investment like the ANE

²⁵ Note that these cost calculations do not include impacts of the social cost of carbon.

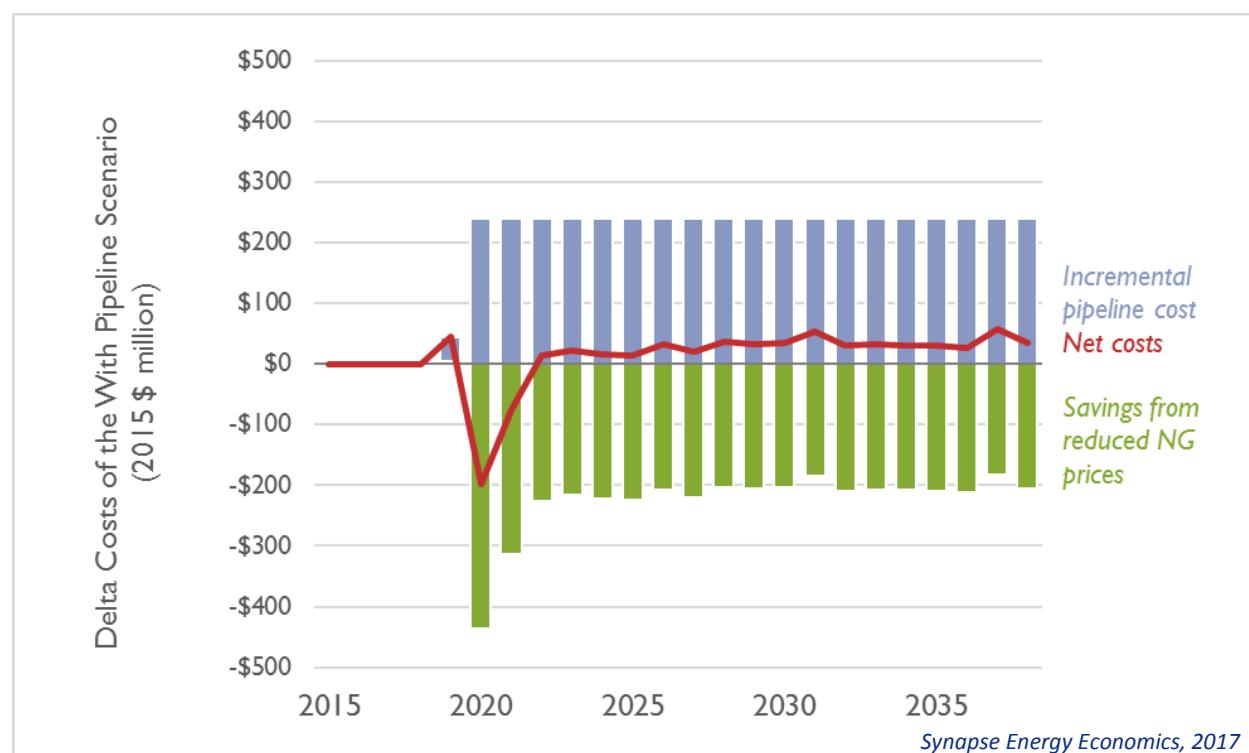
²⁶ This and all following net present value calculations assume a discount rate of 5 percent.

pipeline is unlikely to be the optimal solution. Instead, robust system planning and contingencies in the form of contracts for LNG, increased or accelerated levels of energy efficiency and renewables, or shifting of emissions using RGGI allowance banking would significantly moderate the cost increase in these two years, even in a future without a new natural gas pipeline.

Financial impact of ANE pipeline on Massachusetts ratepayers

We find that the reduction in wholesale electricity prices is not enough to offset the cost increases associated with building and operating a new pipeline (see Figure 7). From 2019 through 2038 (the financial lifetime of the pipeline), the net present value costs of constructing a pipeline are estimated to be \$141 million for Massachusetts ratepayers.

Figure 8. Costs, savings, and net costs to Massachusetts of the Pipeline Case, relative to the Base Case, six-state allocation



Note: Values are shown for the “six-state allocation,” described below.

Financial impact of ANE pipeline in New England as a whole

The New England region sees the same cost trends resulting from the construction, operation, and financing of the ANE pipeline as do Connecticut and Massachusetts. On a present-value basis, the pipeline is expected to impose an increase in costs of \$277 million for all of New England. On average, this works out to an annual cost of \$43 million per year for all New England ratepayers.

System costs under an alternative pipeline cost allocation

In the above calculations, we assumed that the annual cost for constructing and operating the pipeline is distributed across all six New England states proportional to each state's 2015 electric sales, the same assumption used by the proposed pipeline's developers.²⁷ However, both the Massachusetts Supreme Judicial Court and the New Hampshire Public Utilities Commission have ruled against charging electric ratepayers for natural gas pipeline costs. These two states represent approximately 55 percent of regional sales. If electric ratepayers in Massachusetts and New Hampshire do not pay their share of the pipeline costs (absent new state legislation), electric ratepayers in the other four states would shoulder the entire \$0.5 billion annual cost.

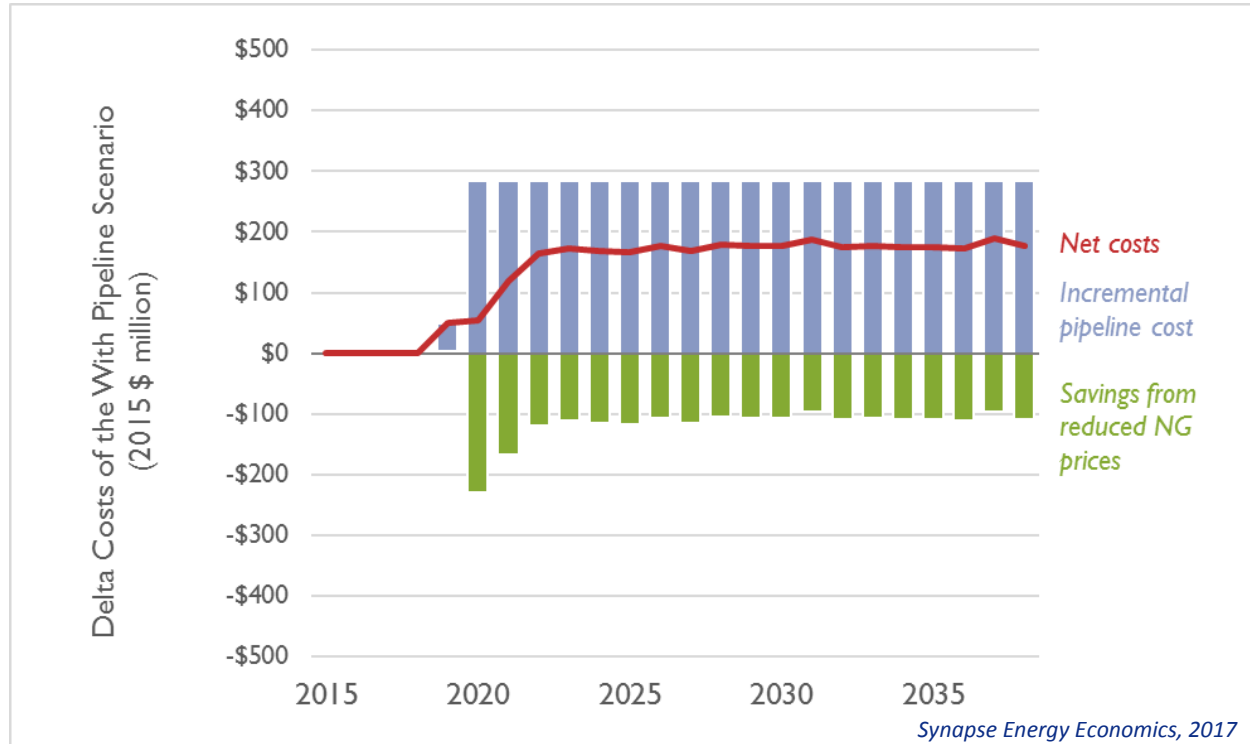
Assuming these costs are split across the four remaining states on a pro-rata basis, Connecticut ratepayers would annual pipeline-related costs increase from \$129 million to \$284 million—an increase of 120 percent (Figure 9). After accounting for system costs resulting from lowered natural gas prices, Connecticut ratepayers would pay \$1.9 billion over the study period, in net present value terms, if Connecticut were to assume responsibility for a greater share of pipeline costs.

Note that it is relatively unlikely that public utility commissions in the other four states would approve of such an extreme cost allocation. In fact, on October 25, 2016, Connecticut cancelled its RFP for gas capacity and gas storage procurement, stating that “Regional investment is necessary to ensure that no one state disproportionately bears the costs of addressing what is a problem endemic to our regional electric system.”²⁸ Likewise, the Rhode Island Public Utilities Commission voted to stay proceedings on the cost allocation of the pipeline, a result of the decisions made in Massachusetts and New Hampshire.

²⁷ Petak direct testimony on behalf of Eversource. DPU 15-181. December 18, 2015.

²⁸ For more information, see [http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/0db222228c36cbcb852580570070ec28/\\$FILE/DEEP%20Notice%20of%20RFP%20Cancellation_10.25.16_Final.pdf](http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/0db222228c36cbcb852580570070ec28/$FILE/DEEP%20Notice%20of%20RFP%20Cancellation_10.25.16_Final.pdf).

Figure 9. Costs, savings, and net costs to Connecticut of the Pipeline Case, relative to the Base Case, four-state allocation



Note: Values are shown for the "four-state allocation."

Figure 10 shows the potential system costs to Connecticut under both the six-state and the four-state allocations. Table 6 shows that depending on the allocation used, the pipeline could cost Connecticut ratepayers between \$85 and \$1,896 million on a net present value basis.

Figure 10. Incremental system costs to Connecticut ratepayers of the Pipeline Case relative to Base Case in the six-state and four-state allocations

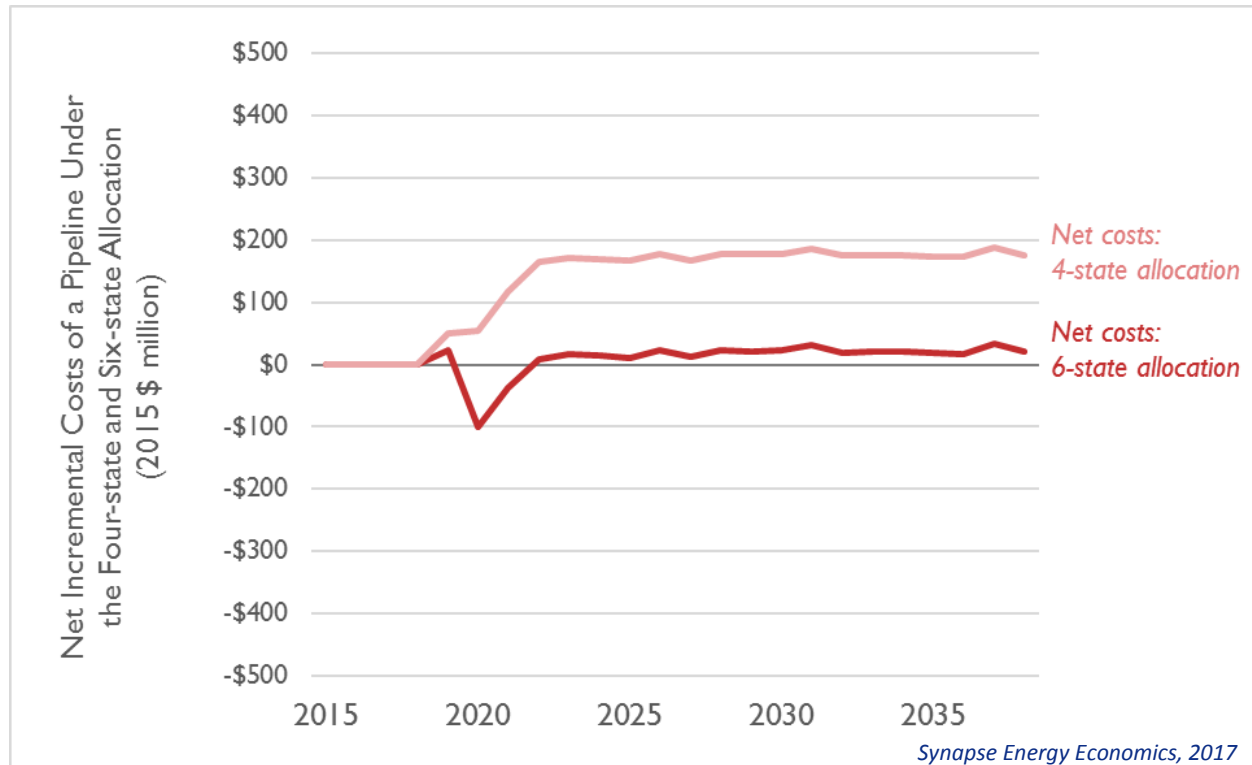


Table 6. 20-year net present values for Connecticut ratepayers in the Base Case, the Pipeline Case, and the increment between the two cases under the four-state and six-state allocations, in million 2015 dollars

	Four-State Allocation	Six-State Allocation
Base Case	\$19,566	\$19,566
Pipeline Case	\$21,462	\$19,651
Incremental cost of the Pipeline Case	\$1,896	\$85

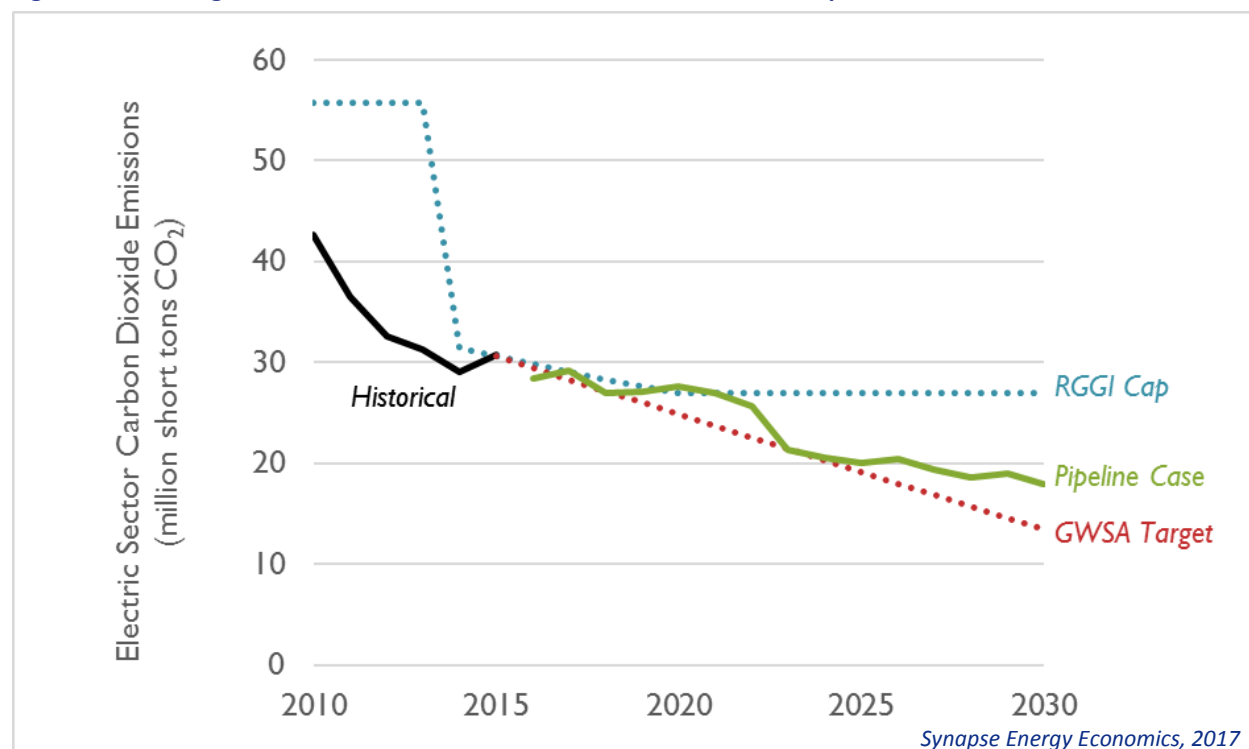
3.3. Compliance with greenhouse gas legislation will require additional reductions in natural gas use

Because of current laws and regulations, natural gas-fired generation in New England is expected to decrease by 27 percent by 2023 and 41 percent by 2030, relative to 2015 levels. These reductions in future natural gas use will result in substantial CO₂ emission reductions. Between 2015 and 2030, region-wide electric-sector CO₂ emissions decrease by 42 percent relative to 2015 (see Figure 11).²⁹

²⁹ Given the small change in natural gas, carbon dioxide emissions are extremely similar in both the Base Case and the Pipeline Case, differing by just 0.2 percent over the entire study period.

Figure 11 also shows a “GWSA Target” level of emissions. This emissions trajectory was derived as part of Synapse’s March 2016 report *The RGGI Opportunity 2.0* and assumes that some policies are implemented to encourage emission reductions outside of the electric sector.³⁰ This trajectory establishes emissions caps for the electric sector to ensure that a level of emissions 40 percent below 1990 levels is met by 2030. The Pipeline Case exceeds the level of allowable emissions under this “GWSA Target” in almost all years, implying that this scenario does not comply with the more-stringent GWSA regulations.

Figure 11. New England electric-sector carbon dioxide emissions for the Pipeline Case



Note: This figure shows carbon dioxide emissions associated with electricity generation only, not CO₂ equivalents of all greenhouse gas emissions. Greenhouse gas emissions associated with upstream sources (such as methane leaks from natural gas fracking or transportation of natural gas via pipelines), greenhouse gases other than CO₂ (including methane, the primary component of natural gas), and greenhouse gases from other sectors of the economy (including emissions resulting from the end-use consumption of fuels in the transportation, commercial, residential, and industrial sectors) are not included. In some years, CO₂ emissions exceed the six-state RGGI Cap by a small margin; these emissions are from resources not covered under the RGGI construct, such as combined heat-and-power, landfill gas, biomass, and some simple-cycle combustion turbines.

In addition to modeling a Base Case and a Pipeline Case, Synapse modeled two other scenarios, a GWSA-Compliant Case (Without Pipeline) and a GWSA-Compliant Case (With Pipeline). These scenarios analyze what would happen to natural gas consumption if compliance with greenhouse gas emission targets is

³⁰ More information on the derivation of this cap is available at http://www.synapse-energy.com/sites/default/files/RGGI_Opportunity_2.0.pdf

attained. In these scenarios, we assumed that all six New England states reach a CO₂ emissions reduction level of 40 percent below 1990 levels by 2030.³¹

These two new scenarios modify the Base Case and the Pipeline Case in the following ways:

- Both the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline) feature tighter caps on electric-sector CO₂ emissions (see Figure 12). These caps are in line with a 5 percent region-wide reduction per year, per the RGGI cap. The 2016 RGGI program review is considering this proposal alongside other revisions.
- Both the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline) expand the electric-sector CO₂ cap to include all emitting electric-sector resources, including those resources currently excluded under RGGI.³²
- Both the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline) feature increased levels of energy efficiency, in line with what leading states such as Massachusetts and Rhode Island achieve today. All New England states are assumed to ramp up to these energy efficiency levels and sustain them throughout the study period, under the assumption that additional revenues from the expanded electric-sector cap would assist in funding these programs.³³
- The GWSA-Compliant Case (Without Pipeline) does not include any new pipeline infrastructure. The GWSA-Compliant Case (With Pipeline) includes the Access Northeast pipeline project, as well as the same price effects modeled in the Pipeline Case.

Otherwise, all assumptions on renewable portfolio standards, new long-term contracts for imports, and resource prices remain unchanged.

Figure 12 shows the electric-sector emissions in the GWSA-Compliant Case (With Pipeline) and compares them to historical electric-sector emissions, allowed emissions under the current RGGI cap, the 40 percent emissions target, and the electric-sector emissions estimated in the non-GWSA

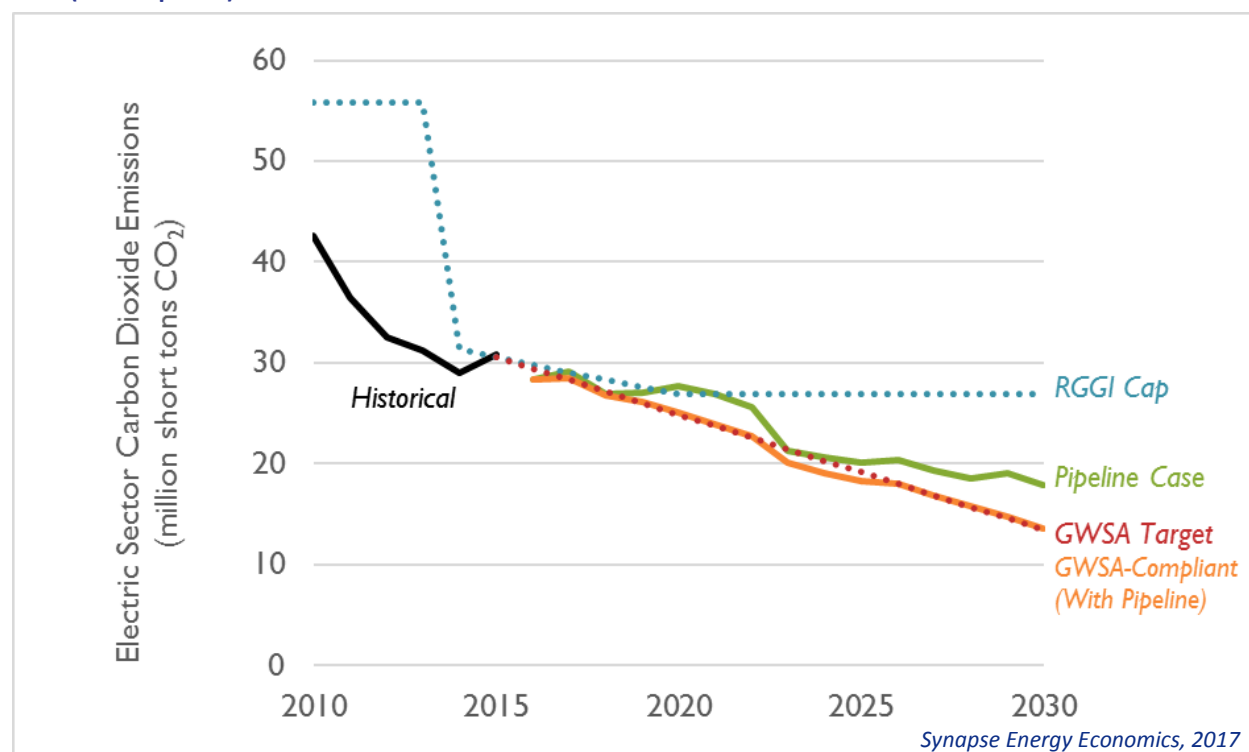
³¹ This level of emissions reduction is an approximation of existing policies: in reality, each of the six states has a different emissions reduction goal, and in some cases the specific 2030 target has not yet been promulgated. Furthermore, each of the states maintains an independent emissions inventory. These inventories account differently for imports and exports of electricity to surrounding New England states and may overlap and in some cases end up double-counting emissions or excluding entire groups of CO₂ emissions. As a result, we focus on the fact that these six states operate under an interconnected energy system and linked economy and that they will establish a mechanism to attribute emission reductions across the states in order to achieve an average reduction in emissions of 40 percent economy-wide across the entire region.

³² Several electric-generating resources are not currently covered under the RGGI cap, including combined heat-and-power, landfill gas, biomass, and some simple-cycle combustion turbines.

³³ In the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline), we ignore any electricity sales increases that would result from electrifying vehicles or end-use heating or water heating. Previous Synapse analyses have found that even substantial electrification of vehicles (e.g., on the order of electrifying one-third of New England's light-duty vehicle fleet) would only result in net sales increases of 5 percent by 2030. This assumption is also predicated on the idea that for each MWh powering a newly-electrified vehicle or heating system, one renewable MWh is added to the New England electric grid, not affecting the overall level of natural gas-fired generation.

compliant Pipeline Case.³⁴ By 2030, electric-sector CO₂ emissions in the GWSA-Compliant Case (With Pipeline) are estimated to be 24 percent lower than 2030 emissions in the non-GWSA compliant Pipeline Case.

Figure 12. New England electric-sector carbon dioxide emissions for the Pipeline Case and the GWSA-Compliant Case (With Pipeline)

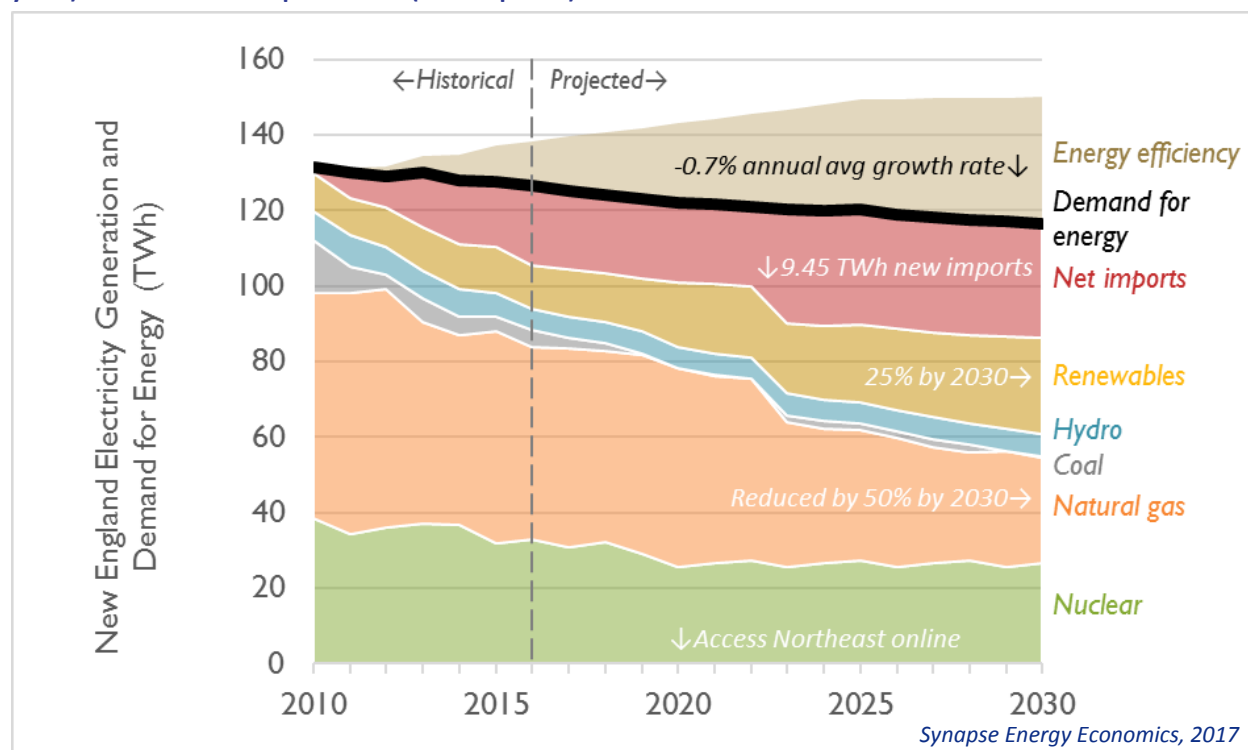


Natural gas use implications

Whether or not ANE or other pipelines are built, these CO₂ emission caps necessitate a decrease in the amount of electricity generated from natural gas power plants in New England, thus reducing the benefits of new pipeline infrastructure. We estimate that by 2023 natural gas-fired generation will decrease by 31 percent relative to 2015 levels and that by 2030 natural gas-fired generation will decrease by 50 percent relative to 2015 levels (see Figure 13).

³⁴ As in the Base Case and the Pipeline Case, the GWSA-Compliant Case (Without Pipeline) and GWSA-Compliant Case (With Pipeline) feature near-identical emissions trajectories.

Figure 13. Electricity generation and demand in New England, 2010 to 2030 (2016 through 2030 are modeled years) in the GWSA-Compliant Case (With Pipeline)



Note: In this figure, “Renewables” includes wind, solar, biomass, and landfill gas. “Hydro” includes in-region hydroelectric plants. “Natural gas” includes both natural gas and petroleum use by generating units typically using natural gas. “Net imports” refers to the electricity imported over existing transmission lines from Canada and New York as well as new long-term contracts for imported renewable electricity.

3.4. Natural gas reductions outside the electric sector will also be required to meet GWSA requirements

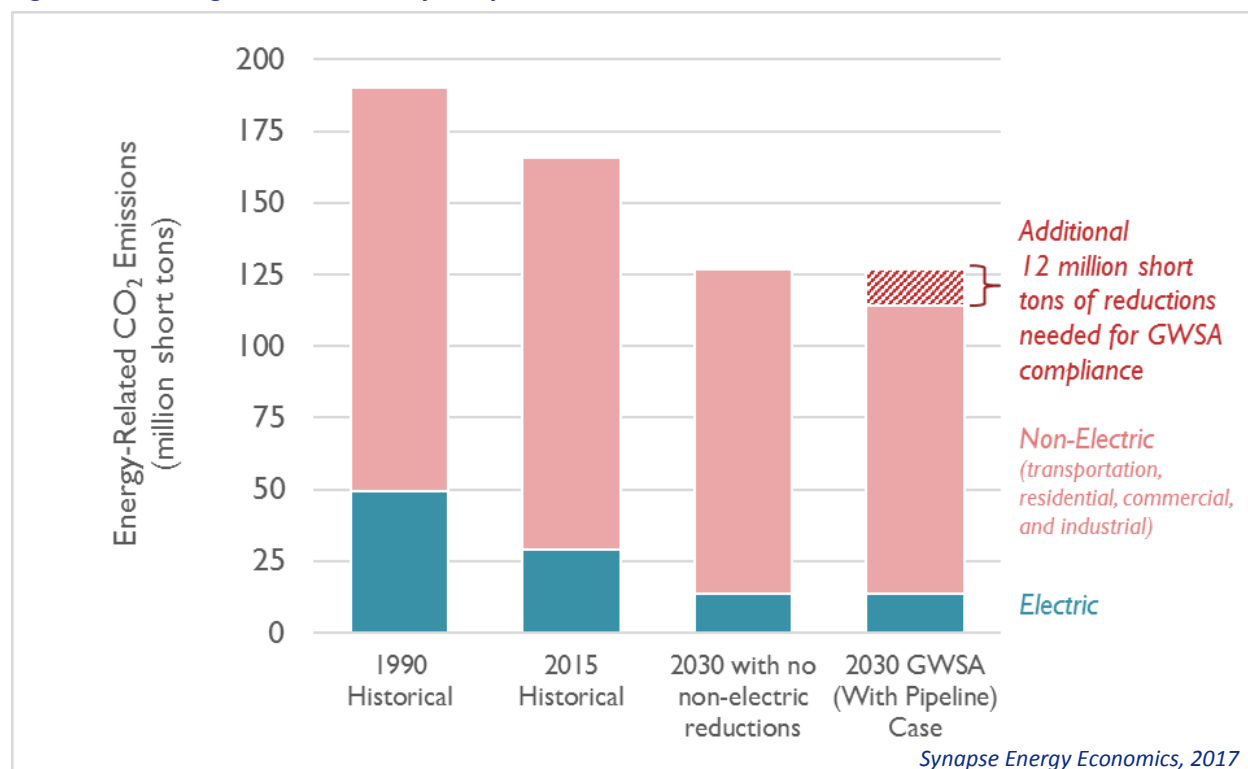
In recent years, as the price of natural gas has dropped compared to other fuels, many New England consumers have switched their home and business heating systems to natural gas. At the same time, states like Connecticut have prioritized natural gas fuel switching as a part of its Comprehensive Energy Strategy.

However, in order to attain greenhouse gas reductions in line with the scientific consensus on averting catastrophic climate change, and to comply with state laws intended to achieve this reduction, all of New England will have to go even further to reduce greenhouse gas emissions. Even if the above electric-sector emission reductions are achieved, further action will be required to decrease CO₂ emissions—and natural gas use—in parts of the economy outside of the electric sector. In 1990, CO₂ emissions from outside of the electric sector represented about three-quarters of New England’s

emissions; by 2015, this number is estimated to have risen to about 80 percent.³⁵ As natural gas-fired electric generation continues to fall in the future, emissions from the residential, commercial, industrial, and transportation sectors will represent a larger and larger share of overall emissions.

Figure 14 shows the share of CO₂ emissions in New England from the electric and non-electric sectors for 1990, 2015, and 2030 under the GWSA-Compliant Case (With Pipeline).³⁶ The 2030 electric-sector CO₂ emissions total modeled in the GWSA-Compliant Case (With Pipeline) implies that 2030 non-electric emissions must be no larger than 101 million tons. Our projection for non-electric emissions (modified to reflect petroleum-to-natural gas fuel-switching in Connecticut) exceeds this level by 12 million tons.

Figure 14. New England emissions trajectory for all sectors



New regulations will be required to ensure that the residential, commercial, industrial, and transportation sectors address this 12 million ton gap. If future emission reductions are implemented in proportion to the recent levels of emissions measured from each fuel in each sector, decreased natural

³⁵ This accounting does not include non-carbon dioxide greenhouse gas emissions (such as methane or sulfur hexafluoride) or emissions from non-energy uses (such as pipeline leakage, agriculture, or upstream fuel extraction and processing). This analysis assumes that greenhouse gas emissions from these sources also undergo reductions commensurate with meeting the 2030 emissions reduction goal of 40 percent below 1990 levels.

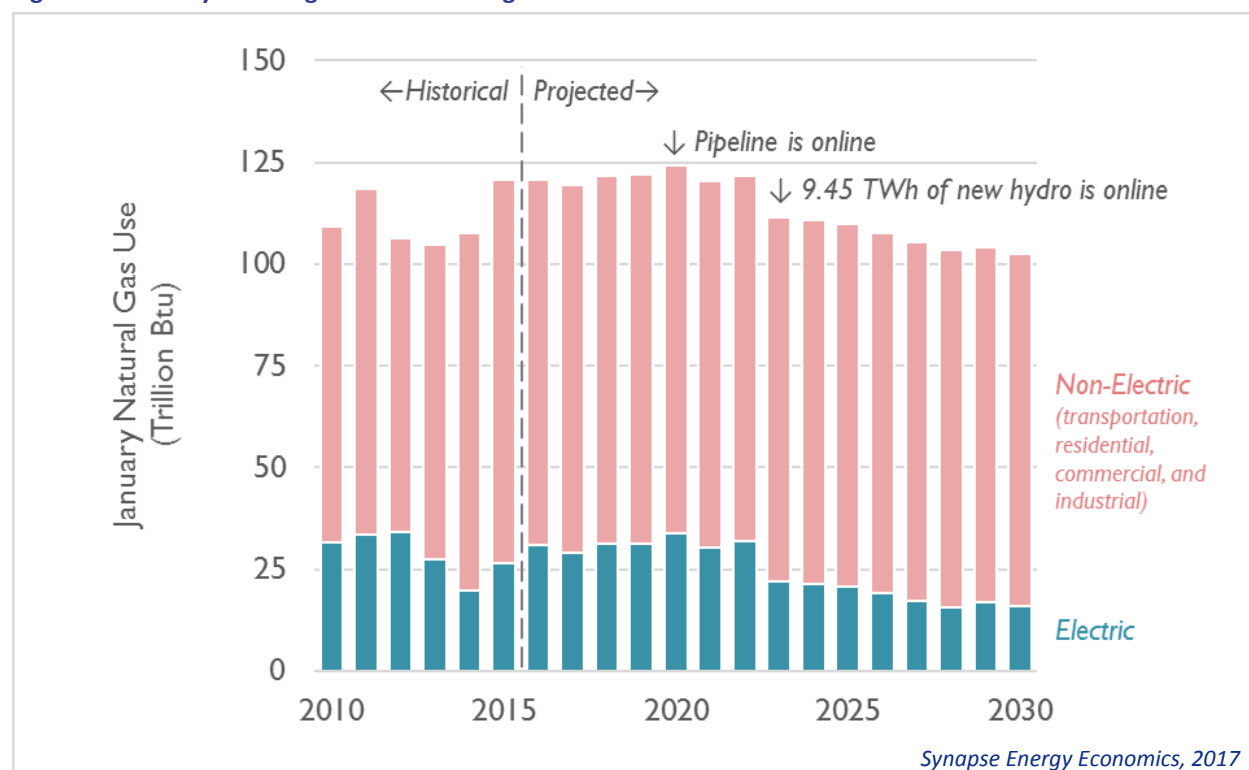
³⁶ The 2030 projection of non-electric emissions and energy use is based on the 2017 Annual Energy Outlook's projected growth rates for end-use energy and emissions, adjusted to reflect petroleum-to-natural gas fuel switching in line with Connecticut's 2013 Comprehensive Energy Strategy. More information on the 2017 Annual Energy Outlook can be found at <http://www.eia.gov/outlooks/aeo/>.

gas use will account for one-quarter of this reduction—3 million tons. Recent historical emissions rates indicate that this is a reduction of 50 trillion Btu by 2030 from non-electric natural gas end uses in New England, requiring average annual reductions of 0.8 percent. By 2030, all-sector natural gas use is expected to be 20 percent lower than 2015 levels.

Monthly trends in peak natural gas use

Natural gas use is seasonal. Demand for electricity and, by association, natural gas use by the electric sector, peaks in the summer months. However, total consumption of natural gas across all sectors typically peaks in the winter months when both the electric sector and non-electric users are calling on pipelines for fuel. In every year from 2010 to 2015, total natural gas use from both the electric and non-electric sectors peaked in January. In our modeling, natural gas use also peaks in January in each year. Figure 15 shows the demand for natural gas in January from the electric and non-electric sectors, both for 2010 to 2015 (historical) and 2016 to 2030 (modeled). The values in this figure give a sense of the peak capacity currently reached with the region’s natural gas pipeline infrastructure.

Figure 15. January natural gas use in New England



Note: In this figure, only energy use associated with natural gas is shown. All other energy (including that associated with petroleum use at primarily-natural gas-fired power plants) is excluded.

This figure shows that the month with the maximum natural gas use is January 2020, the same year that the pipeline achieves full operation. The use of natural gas is forecasted to significantly decline starting in 2023—just a few years after the pipeline is expected to be operational. In January 2020, natural gas

use region-wide is projected to be 3 percent greater than natural gas use in the peak month of 2015. However, just three years later, as a result of energy efficiency measures, new renewables, emission caps, and a new transmission line importing hydroelectricity and renewables to the region, peak monthly natural gas use declines by 7 percent compared to 2015 levels. By 2030, peak monthly natural gas use declines even further to 15 percent below January 2015 levels. As a result, even during the coldest months of the year, far less natural gas will be transported through New England pipelines, likely relieving existing pipeline constraints and rendering a new pipeline underutilized.

While analysis of daily natural gas consumption would help establish the actual level of peak usage in the current natural gas pipeline system, this monthly analysis shows that peak monthly natural gas consumption is expected to decline over time, rather than continue to increase. This decrease in natural gas usage is largely due to reductions in electricity generation from natural gas.

3.5. Does Access Northeast make sense?

Given declining natural gas use over time, a long-term investment of \$6.6 billion in the ANE natural gas pipeline is not a reasonable or cost-effective way to address pipeline capacity constraints or price spikes—both of which are likely to be short-term situations. Instead, alternative short-term, targeted strategies such as increased ship-borne LNG deliveries, marketplace rules to ensure fuel backup to natural gas, or smaller and more strategic deployments of pipeline infrastructure are much more likely to be cost-effective over the long term.³⁷

In fact, all of these strategies are currently being implemented. LNG deliveries to New England totaled 27 billion cubic feet in the 2015-2016 winter, more than doubling the level of LNG imports measured just two winters prior. ISO-NE continues to roll out its Pay-for-Performance rules, which will replace the currently-existing “winter reliability” program. This program encourages generators with dual-fuel capabilities to keep a supply of oil onsite in case of temporary natural gas shortages and penalizes generators who cannot perform during times of greatest need.

Finally, a number of other major pipeline projects are either currently online or proposed by pipeline developers to come online in advance of the Access Northeast pipeline: the Algonquin Incremental Market (AIM) Expansion, the Tennessee Gas Pipeline – Connecticut Expansion, and the Atlantic Bridge expansion (see Table 7).³⁸ Pipeline developers plan for all three projects to be operational by November 2017 (two years before Access Northeast). As planned, these projects would increase the capacity of the New England natural gas pipeline network by 0.54 billion cubic feet per day. This is roughly 60 percent of the entire capacity of the daily deliverability of the Access Northeast pipeline project. If built, these

³⁷ Increased energy efficiency, demand response, or renewables are also potential strategies for dealing with the price constraints that New England ratepayers may encounter in the short-term.

³⁸ Our modeled natural gas prices do not take account for these additions to current pipeline infrastructure.

projects would decrease pipeline constraints—in advance of Access Northeast—and would decrease the impact of any natural gas price reductions associated with Access Northeast itself.

Table 7. Recently-completed and planned natural gas pipeline projects in New England

Project Name	Capacity (Bcf per day)	Online Date
AIM	0.34	November 2016
Tennessee Gas Pipeline – Connecticut Expansion	0.07	November 2017
Atlantic Bridge	0.13	November 2017
Total New Pipeline Capacity	0.54	November 2017

4. MAJOR FINDINGS

With or without a pipeline, existing laws and regulations are expected to significantly decrease natural gas use for electric generation in New England. As a result of this decrease in natural gas use, the Access Northeast pipeline is expected to produce net costs for ratepayers in Connecticut, Massachusetts, and throughout New England.

First, with or without a new pipeline, existing laws and regulations will cumulatively require New England’s use of natural gas for electric generation to decrease by 27 percent by 2023, relative to 2015 levels.

Natural gas use is forecasted to decline dramatically starting in 2023—just a few years after the ANE pipeline is supposed to be fully operational. Existing laws—renewable portfolio standards, energy efficiency resource standards, long-term requirements for additional hydropower and wind power, and carbon dioxide (CO₂) emissions caps—require a significant reduction in natural gas-fired generation throughout New England. This decrease in overall gas use will reduce capacity constraints of existing pipelines and the need for new pipelines. By 2023, shortly after ANE’s construction, natural gas-fired generation is estimated to be 27 percent lower than in 2015. And by 2030, natural gas-fired electric generation is estimated to be 41 percent lower than in 2015.

Second, the ANE pipeline will cost New England consumers \$6.6 billion, not \$3.2 billion as previously reported.

Proponents of ANE have publicized an expected pipeline construction cost of \$3.2 billion. However, according to expert witness testimony for Eversource, one of the main project proponents, after taking into account additional costs, including operations and maintenance, depreciation expenses, and return on equity, the ANE pipeline is expected to cost \$0.5 billion per year for 20 years—about \$6.6 billion in present value terms. The pipeline developers seek to charge these costs to electric ratepayers throughout New England.

Third, if the pipeline is built, New England ratepayers will pay additional costs of \$277 million over its lifetime.

Even if the ANE pipeline reduces constraints and gas prices, it will cause overall price increases on consumers throughout New England, due to the cost of the pipeline itself. The pipeline is expected to impose net costs of \$277 million for all New England electric ratepayers on a present-value basis.

Fourth, if the pipeline is built, electric ratepayers in Massachusetts and Connecticut will pay additional costs of \$141 million and \$85 million, respectively.

Massachusetts ratepayers will see cost increases associated with the ANE pipeline. Our analysis shows that Massachusetts electric ratepayers will pay additional costs of \$141 million over the life of the pipeline.

Connecticut ratepayers will be looking at additional costs of \$85 million over the lifetime of the pipeline. If the pipeline were built without the support of electric ratepayers in Massachusetts and New Hampshire, the costs to Connecticut ratepayers could be as high as \$1.9 billion. The Connecticut Department of Energy & Environmental Protection has stated that this approach would burden the state's ratepayers with disproportionate costs.

Fifth, implementing emission reduction mandates and targets under each New England state's global warming solutions laws will cause economy-wide natural gas use to decrease by 20 percent by 2030, despite recent policies and trends that incentivize fuel-switching to natural gas.

In recent years, as the price of natural gas has dropped compared to other fuels, many New England consumers have switched their home and business heating systems to natural gas. At the same time, some states have prioritized natural gas fuel-switching, including Connecticut as a part of its Comprehensive Energy Strategy.

However, in order to attain greenhouse gas reductions in line with the scientific consensus on averting catastrophic climate change—and to comply with state laws intended to achieve this reduction—all of the New England states will have to go even further to reduce greenhouse gas emissions. Achieving the greenhouse gas emission reduction goals of the six-state region will require economy-wide CO₂ emissions to decrease by 40 percent by 2030, relative to 1990 levels. Additional regulations will likely be needed to reduce emissions from residential and commercial buildings, as well as from transportation and throughout industry. These policies will promote more reductions in natural gas, beyond the electric sector.

Synapse also modeled two additional scenarios (with and without the ANE pipeline) in which each New England state imposes more stringent emissions caps to comply with legal mandates or agreements under the Global Warming Solutions Act or similar legislation and targets. Even after accounting for expected fuel-switching and other load growth in the non-electric sectors, total natural gas use in these scenarios is expected to fall by 20 percent, relative to 2015. This will further reduce the need for ANE and other natural gas pipeline infrastructure.

Conclusion

Our modeling shows that if the ANE pipeline is built as proposed, ratepayers will bear substantial net cost increases on their utility bills, even if the pipeline alleviates winter price spikes. Furthermore, within several years of the pipeline's construction, the overall need for natural gas in New England's electric sector is expected to decline dramatically as states work toward compliance with existing laws and regulations. The decline in natural gas use for electric generation indicates that even existing gas pipelines may operate under capacity and that ANE—or other new pipeline infrastructure—will not be needed to supply either electric generators or gas heating customers.³⁹

Under these circumstances, spending \$6.6 billion on a new pipeline meant to provide natural gas year-round to electric power plants is not a reasonable or cost-effective way to address pipeline capacity constraints.

³⁹ Note that this analysis does not include the impacts of the just-completed AIM Project, or the proposed TGP-CT Expansion and Atlantic Bridge pipeline projects, and does not rely on any assumptions related to the success or failure of those proposals. As proposed, each of these projects would reduce pipeline constraints. This is likely to lower regional natural gas prices and render ANE that much less economical and less needed.

APPENDIX A: MODELING METHODOLOGY

In this analysis, Synapse used two models in conjunction with one another: EnCompass (Version 2.0), a state-of-the-art capacity expansion and production cost model produced by Anchor Power Solutions, and M-SEM, a state-specific spreadsheet model developed by Synapse and used for tracking historical and projected energy use and emissions from the residential, commercial, industrial, and transportation sectors.

The EnCompass Model

EnCompass is a single, fully integrated power system platform that provides an enterprise solution 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: Modeling Inputs. Synapse populated the model with a custom New England dataset developed by Anchor Power and based on the 2015 Regional System Plan,⁴⁰ which has been validated against actual unit-specific 2015 dispatch data. EnCompass was used to optimize the generation mix in New England and to estimate the costs of a changing energy system over time. Because this study concentrates on gas usage in the aggregate, rather than at any specific units, 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.

The Multi-Sector Emissions Model

Synapse has developed the Multi-Sector Emissions Model (M-SEM), a state-specific model used for tracking historical energy use and emissions and for projecting future energy use and emissions based

⁴⁰ ISO-NE. “2015 Regional System Plan.” Available at: <https://www.iso-ne.com/system-planning/system-plans-studies/rsp>



on a set of policy changes. This dynamic spreadsheet model includes state-specific information on energy use and emissions in the electric, residential, commercial, industrial, and transportation sectors. It employs historical data from the Energy Information Administration (EIA) and the Annual Energy Outlook (AEO) 2017, the most recent release of the EIA's annual AEO report.⁴¹

More information on M-SEM is available at <http://www.synapse-energy.com/MSEM>

Temporal Scope

The time period of this analysis is 2016 to 2040, with a focus on data through the year 2030. EnCompass modeling is performed at one-year intervals starting in 2016. Historical data through 1990 has been included in the spreadsheet model to serve as a point of comparison for future emissions. M-SEM includes historical energy and emissions data through 1990 and models non-electric energy use and emissions through 2040.

Geographic Scope

EnCompass was used to model all six New England states with unit-specific resolution. The ISO New England system was modeled as thirteen separate balancing areas. Trade between the areas in New England was constrained by the region's major transmission paths. Transfers between New England and its neighbors, including New York, Quebec, and New Brunswick, were modeled as set import/export patterns based on actual 2015 hourly flows.

Modeled Scenarios

Using these two models, Synapse analyzed two scenarios:

- **The Base Case:** A future in which no new policies are enacted and no new pipeline infrastructure is constructed. The Base Case includes all laws and regulations known as of December 2016.
- **The Pipeline Case:** A modification of the Base Case that assumes that the Access Northeast pipeline is constructed and that it alleviates natural gas pipeline constraints into New England in winter months, resulting in lower natural gas prices.

We also modeled two additional scenarios, on the basis of deeper future emissions cuts. These scenarios modify the Base Case and the Pipeline Case, examining what happens to natural gas when the New England states impose more stringent emissions caps to comply with existing legal mandates. These more stringent rules—more specific than what is currently known—would require further reductions in

⁴¹ Energy Information Administration. 2017. Annual Energy Outlook 2017, released January 6, 2017.

CO₂ emissions from all sectors, ensuring that the six states are on track to meet their legally-mandated emissions reductions targets and goals.

- **GWSA-Compliant Case (Without Pipeline):** In this modification of the Base Case, we assume that New England states meet their emission reduction targets, which coalesce at a level of 40 percent below 1990 levels by 2030. This scenario assumes the ANE pipeline is not built.
- **GWSA-Compliant Case (With Pipeline):** This scenario combines the effects of the Pipeline Case and the GWSA-Compliant Case, and it examines the impact of both building the Access Northeast pipeline and achieving emission reductions in line with state legislation. As in the Pipeline Case, we assume that natural gas prices will be lowered as a result of new pipeline infrastructure.



APPENDIX B: MODELING INPUTS

In order to isolate the impacts of the Access Northeast pipeline project, each of the four scenarios modeled in this analysis use the same assumptions on unit additions, unit retirements, renewable energy costs, and carbon dioxide markets. The Base Case and the Pipeline Case use the same set of assumptions for electric sales and energy efficiency, while the GWSA-Compliant Case (Without Pipeline) and GWSA-Compliant Case (With Pipeline) use a different, more aggressive energy efficiency trajectory.

Note that these inputs were finalized in December 2016. As such, they do not incorporate new proposed generating capacity, revisions to unit retirements, or updates to renewable portfolio standards and energy efficiency resource standards that have been announced since that date.

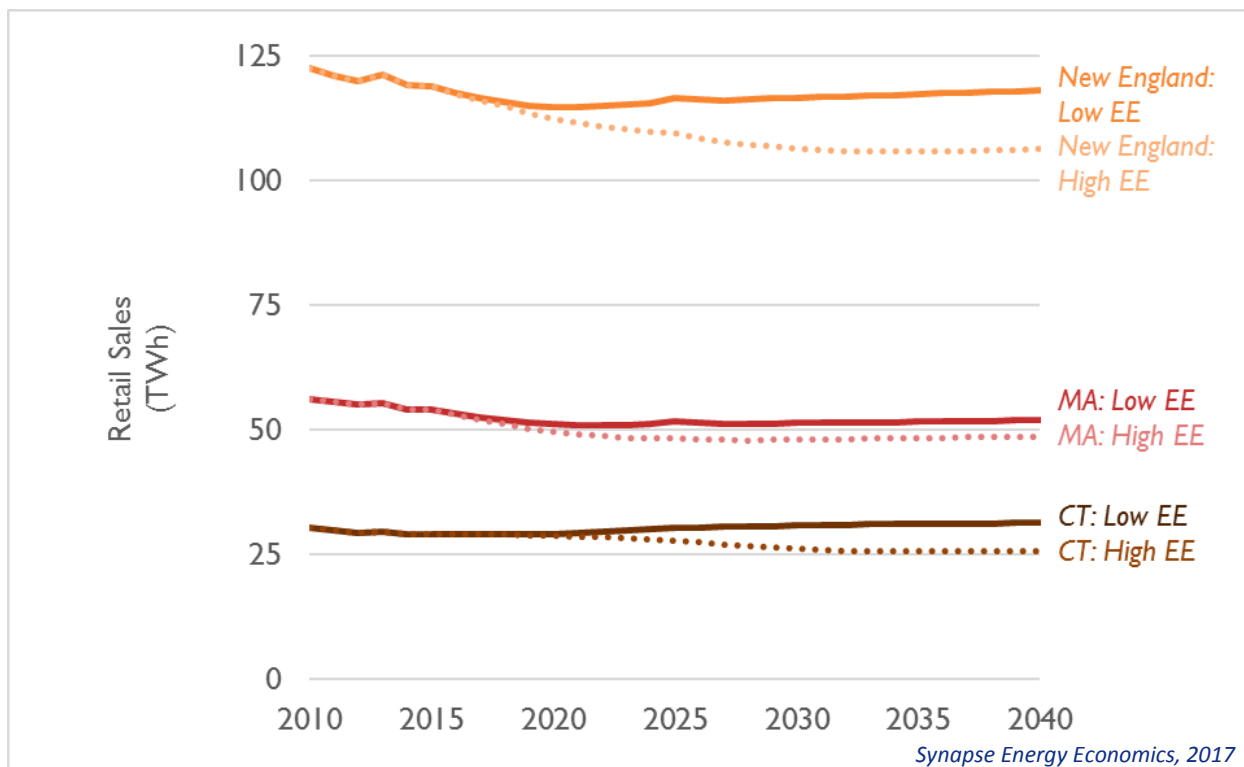
Electric sales and energy efficiency

ISO New England's Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) is the basis for the load forecast used in this study.⁴² The 2016 CELT forecast provides peak loads and total consumption by year through 2025. Synapse's baseline load forecast assumption through 2025 is based on the CELT forecast, grossing up for behind-the-meter solar and passive demand response. Thereafter, Synapse assumes the average compound annual growth rate (CAGR) for 2026-2040 from AEO 2017 is in place through 2040.

This baseline load forecast does not assume any new energy efficiency. In the Base Case and the Pipeline Case, Synapse has modified the load forecast to include new energy efficiency as reflected by the most recent data from state compliance filings (when applicable) or from EIA Form 861 for states that do not require energy efficiency compliance filings. In the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline), Synapse has assumed all states achieve annual incremental energy efficiency levels of 3 percent (see Figure 16). This level of energy efficiency aligns with what the leading states of Massachusetts and Rhode Island achieve today.

⁴² ISO-NE. 2016-2025 Forecast Report of the Capacity, Energy, Loads, and Transmission (CELT Report). Available at: https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls

Figure 16. Retail sales of electricity



Note: The “Low EE” trajectory is used in the Base Case and the Pipeline Case. The “High EE” trajectory is used in the GWSA-Compliant Case (Without Pipeline) and the GWSA-Compliant Case (With Pipeline).

Unit additions

Synapse allowed EnCompass to add new units if doing so lowered overall system costs. Unit cost assumptions are described below. In addition to new units that are added for economic reasons by the model, Synapse made three more assumptions regarding proscribed new units added in every scenario:

- First, all units listed as “under construction” in the final 2015 version of EIA form 860 were hard-coded into the model as proscribed builds. This includes new wind, utility-scale photovoltaics (PV), hydro, and/or fossil-fired resources. Table 8 presents a summary of the state in which the units are coming online, the associated plant and utility, and each unit’s capacity, anticipated in-service year, and generation technology.
- Second, Synapse assumed that all current RPS policies are followed. To the extent that the RPS policies were not met with economic resource additions alone, units were added by the model to meet the policies according to relative resource costs among the set of resources that are eligible for each state’s RPS. In the case of Massachusetts, we note that the current RPS requires the addition of at least 1,600 megawatts (MW) of offshore wind capacity by 2027.⁴³ All four

⁴³ See <https://malegislature.gov/Bills/189/House/H4568> for more information.

scenarios assume that this requirement is met and, therefore, that at least this amount of offshore wind will be constructed. Please see the “Resource Potentials and Cost Inputs” section below for additional information on resource potentials and costs.

- Third, in accordance with current Massachusetts law, a new transmission line to import hydropower from Canada has been hard-coded into the model, with the assumption of 9.45 TWh of imports by 2023.⁴⁴

Synapse has proscribed a rooftop solar capacity buildout trajectory in the New England states. See the “Resource Potential and Costs” section for further details.

Table 8. New England states’ expected unit additions

State	Plant Name	Utility	Capacity (MW)	Online Year	Fuel Type	Unit Type
CT	Bridgeport Energy 1	Unknown	22	2018	Gas	GT
CT	CPV_Towantic	Unknown	725	2018	Gas	CC
CT	Wallingford Unit 6 and Unit 7	Unknown	90	2018	Gas	GT
CT	UDR Glastonbury Fuel Cell	UIL Distributed Resources, LLC	3.4	2016	Natural Gas	Fuel Cell
CT	Connecticut Municipal Electric Energy Co	SolarCity Corporation	2.5	2016	Solar	PV
CT	Connecticut Municipal Electric Energy Co	SolarCity Corporation	1	2016	Solar	PV
CT	Lebanon Solar 1	Windham Solar LLC	2	2016	Solar	PV
CT	Lebanon Solar 2	Windham Solar LLC	2	2016	Solar	PV
CT	UI RCP Bridgeport Seaside	United Illuminating Co	2.2	2016	Solar	PV
MA	Salem Harbor	Footprint Salem Harbor Development LP	158.4	2017	Natural Gas	Combined Cycle
MA	Salem Harbor	Footprint Salem Harbor Development LP	158.4	2017	Natural Gas	Combined Cycle
MA	Salem Harbor	Footprint Salem Harbor Development LP	240.7	2017	Natural Gas	Combined Cycle
MA	Salem Harbor	Footprint Salem Harbor Development LP	240.7	2017	Natural Gas	Combined Cycle
MA	BJ’s Wholesale Club, Inc- Uxbridge	SolarCity Corporation	1	2016	Solar	PV
MA	Carver MA 1	Clean Energy Collective LLC	2	2017	Solar	PV
MA	Hewlett-Packard (HP) - Andover, MA	SolarCity Corporation	1.7	2016	Solar	PV
MA	Rail Trail	Altus Power America Management, LLC	2	2016	Solar	PV

⁴⁴ Ibid.

State	Plant Name	Utility	Capacity (MW)	Online Year	Fuel Type	Unit Type
MA	Rising Paper	Altus Power America Management, LLC	2.5	2016	Solar	PV
MA	Town of Needham VNEM	SolarCity Corporation	3	2016	Solar	PV
MA	Wareham MA 1	Clean Energy Collective LLC	2	2016	Solar	PV
MA	Westport MA 1	Clean Energy Collective LLC	1.3	2016	Solar	PV
MA	Westport MA 2	Clean Energy Collective LLC	1.2	2016	Solar	PV
MA	Williamsburg Solar LLC VNEM	SolarCity Corporation	2.2	2016	Solar	PV
MA	Future Generation Wind	Consolidated Edison Solutions Inc	8	2016	Wind	On-shore
ME	Athens Energy	Athens Energy, LLC	8.5	2016	Biomass	Other
ME	Bingham Wind	First Wind O&M, LLC	186	2016	Wind	On-shore
ME	Hancock Wind Plant	First Wind O&M, LLC	51	2016	Wind	On-shore
ME	Passadumkeag Windpark LLC	Passadumkeag Windpark LLC	39.9	2016	Wind	On-shore
ME	Pisgah Mountain Wind	Pisgah Mountain, LLC	9.1	2016	Wind	On-shore
NH	Nashua Plant	EPP Renewable Energy	1.6	2016	Landfill Gas	ICE
NH	Jericho Power	Jericho Power LLC	14.3	2016	Wind	On-shore
RI	Block Island Wind Farm	Deepwater Wind Block Island LLC	30	2016	Wind	Off-shore
RI	WED Coventry 1	WED Coventry One, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 2	WED Coventry Two, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 2	WED Coventry Two, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 2	WED Coventry Two, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 3	WED Coventry Three, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 4	WED Coventry Four, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 5	WED Coventry Five, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 6	WED Coventry Six, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 6	WED Coventry Six, LLC	1.5	2016	Wind	On-shore
RI	WED Coventry 6	WED Coventry Six, LLC	1.5	2016	Wind	On-shore
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam



State	Plant Name	Utility	Capacity (MW)	Online Year	Fuel Type	Unit Type
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Ball Mountain Hydro	Blue Heron Hydro LLC	0.2	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Townshend Hydro	Blue Heron Hydro LLC	0.1	2016	Hydro	Dam
VT	Sudbury Solar	Ecos Energy LLC	2	2016	Solar	PV

Unit Retirements

Table 9 on the following pages lists all announced unit retirements for the six New England states. Retirement data is based on the 2015 edition of EIA's Form 860, supplemented by ongoing Synapse research. Note that several units in Table 9 do not have announced retirement dates as of yet and are listed for informational purposes only.



Table 9. New England states' expected unit retirements

State	Plant Name	Nameplate Capacity (MW)	Fuel Type	2015 Capacity Factor	Retirement Year
CT	Bridgeport Station 3	400	Coal	17%	2021
CT	Bridgeport Station 4	19	Oil	1%	2017
MA	Brayton Point 1	241	Coal	27%	2017
MA	Brayton Point 2	241	Coal	25%	2017
MA	Brayton Point 3	642.6	Coal	21%	2017
MA	Brayton Point 4	476	Gas	5%	2017
MA	Mass Inst Tech Cntrl Utilities/Cogen Plt CTG1	21	Gas	71%	2019
MA	Pilgrim Nuclear Power Station 1	670	Nuclear	98%	2019
NH	Merrimack 1	114	Coal	23%	None
NH	Merrimack 2	345.6	Coal	19%	None
NH	Schiller 4	50	Coal	20%	None
NH	Schiller 5	50	Coal	72%	None
NH	Schiller 6	50	Coal	17%	None

Renewable Energy Potential

We use assumptions from a 2016 NREL analysis on the total available potential for wind and solar energy (see Table 10).⁴⁵ NREL develops both a technical resource assessment (the total available resource) and an economic potential assessment (the amount of that resource that is feasible to build). We use the technical potential for this study as a cumulative limit on new renewable capacity, with an assumed annual build limit of 5 percent of the technical potential. We arrive at a total available capacity of 16.6 gigawatts (GW) of on-shore wind power and 825 GW of utility-scale solar in the New England states.

⁴⁵ <http://www.nrel.gov/docs/fy12osti/51946.pdf>.

Table 10: Total on-shore wind and solar resource potential (GW)

	Wind	UPV
CT	0.2	17
MA	1.2	63
ME	11	661
NH	2.0	38
RI	0.0	10
VT	3.0	36
Total	16.6	825

Renewable Energy Costs

Solar

We assume cost reduction trajectories for utility and rooftop solar PV based on the NREL's SunShot Vision study, which describes significant cost reductions from baseline levels by 2020. We assume costs decline 62.5 percent from 2010 levels by 2020 and 75 percent by 2030, reaching \$1.00 per watt installed (in 2015 dollars) for utility-scale installations in 2030. While module costs have been well below \$1.00 per watt in recent years, the many other costs to permit and construct a solar plant (soft costs) have persistently kept realized costs higher.

EnCompass is a supply-side-only model: it does not optimize the decisions end users would make to install rooftop PV systems. Rooftop solar inputs are constant across scenarios and are based on the latest ISO-NE solar forecast. According to this data, rooftop PV is predicted to grow to 2,931 MW region-wide by 2030. Table 11 shows the state-by-state breakout of this distributed PV trajectory.

Table 11: Cumulative rooftop photovoltaic installed by state (GW)

States	2015	2020	2025	2030
CT	190	449	585	750
MA	864	1,284	1,436	1,601
ME	13	22	31	42
NH	17	35	47	60
RI	28	156	185	215
VT	122	211	239	262
Total	1,233	2,158	2,523	2,931



Onshore Wind

Our costs for land-based wind are based on research done for the Department of Energy's recent *Wind Vision Report*.⁴⁶ Base wind costs in 2015 are \$1,759 per kilowatt (kW) for projects in Class 3 areas. The *Wind Vision Report* assumes cost reductions and capacity factor increases over time for land-based wind. In this analysis, we hold base costs for land-based wind constant in real terms over the study period at the levels cited above, but we use the increasing capacity factors from the *Wind Vision*. Land-based capacity factors are 35 percent in 2020 and increase to 40 percent by 2050.

Offshore Wind

Offshore wind costs are also taken from the *Wind Vision* assumptions, in which costs are forecasted to fall over time. Base overnight costs for shallow offshore wind resources in 2020 are \$4,471 per kW in Class 3 areas and \$4,052 per kW for projects in all other areas. These costs fall by roughly 30 percent over the study period. Fixed operations and maintenance for shallow offshore wind is \$109 per kW-year in 2020, falling to \$94 per kW-year in 2040.

We assume offshore wind will be built consistent with Massachusetts House Bill 4385 in the following years:

Table 12: Offshore wind builds by year in Massachusetts

Date of solicitation	Online Date	Capacity (MW)	Cumulative Capacity (MW)
Jun 2017	Jun 2020	400	400
Jun 2019	Jun 2022	400	800
Jun 2021	Jun 2024	400	1,200
Jun 2023	Jun 2026	400	1,600

Regional imports over new transmission lines

We assume the state of Massachusetts will procure long-term contracts for imports consistent with House Bill 4385 (see Table 13). Note that these incremental imports are in addition to the current level of imports. We assume no new transmission lines are constructed between the New England states or between New England and New York.

Table 13. Incremental long-term contracted imports

Date of solicitation	Online Date	Capacity (MW)	Generation (GWh)
Jun 2017	Jan 2023	1,200	9,450

⁴⁶ U.S. Department of Energy. 2015. *Wind Vision Report*. Accessed June 22, 2015. Available at: <http://energy.gov/eere/wind/wind-vision>.

Carbon dioxide markets

Despite uncertainty surrounding the impact of the Clean Power Plan in federal courts and in the forthcoming political climate, RGGI caps will remain in place and are projected to be more stringent than the Clean Power Plan caps for the six New England states. Synapse modeled the RGGI cap at current levels, with the total cap pro-rated for New England based on historical allowance allocations. This approach inherently assumes minimal trading between New England and the other RGGI states (which include New York, Maryland, and Delaware). RGGI was also modeled without banking provisions to enable more rapid processing times. In the Base Case and the Pipeline Case, a fifty-dollar nominal alternative compliance cost was assumed (simulating increased trading) to avoid unrealistically-high spikes in the price of RGGI allowances due to the retirement of the Pilgrim nuclear facility by 2020. The GWSA-Compliant (With Pipeline) Case and GWSA-Compliant (Without Pipeline) Case were modeled without an alternative compliance cost to ensure that the six New England states would comply with their mandated emission reduction goals.

In addition to RGGI, Synapse applied the newly-released Massachusetts GHG caps to applicable generating units in Massachusetts. We assumed no trading or banking for these caps.



APPENDIX C: NATURAL GAS PRICE PROJECTION

We predict that a new natural gas pipeline paid for by electric ratepayers (as is the case with Access Northeast) will affect costs in two main ways: first, it will decrease natural gas prices delivered to electric generators in New England by alleviating east-west pipeline constraints. This will result in overall decreased wholesale electric prices. Second, a new pipeline will increase system costs by virtue of having to pay for the pipeline itself.

Projecting the price of natural gas

Synapse used a combination of short-term and long-term forecasts to produce the natural gas price series used in this modeling. First, Synapse calculated a baseline forecast for the Algonquin Citygate in a future with no new natural gas pipelines. To do this, Synapse downloaded monthly NYMEX futures data for Henry Hub (with data available from December 2016 through December 2019).⁴⁷ Monthly prices from this time period were averaged from 2017 to 2019 to create annual average prices. Annual prices were forecasted through 2040 by applying the 2019 to 2030 cumulative average growth rate (2.0 percent per year) in Henry Hub natural gas prices from the 2017 Annual Energy Outlook (AEO).⁴⁸ Next, trends in average monthly prices at Henry Hub were determined by calculating the average monthly variation from the annual average price for each year from 2017 through 2019, then finding the monthly-specific average across each of these three years. For all months before 2020, the monthly NYMEX futures price was used to forecast Henry Hub prices. For all months after 2020, the average annual Henry Hub price for that year was multiplied by its monthly-specific modifier.

Next, Synapse used monthly NYMEX future 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 December 2016 through the furthest date available, November 2019. Using the average basis prices in 2015 dollars per MMBtu for each month in 2017 through 2019, Synapse calculated the average monthly basis price for Algonquin Citygate from Henry Hub. For all months before 2020, the monthly NYMEX futures prices for Henry Hub were added to the Algonquin Citygate bases to forecast Algonquin Citygate Prices. For all months after 2020, the average monthly basis price for Algonquin Citygate was added to the forecasted monthly Henry Hub price.

To calculate the price effects of constructing the Access Northeast pipeline, Synapse assumed that any new west-east pipeline would reduce wintertime pipeline constraints. As a result, natural gas prices in New England would mirror those prices at the TETCO M3 Hub (located downstream of New England in

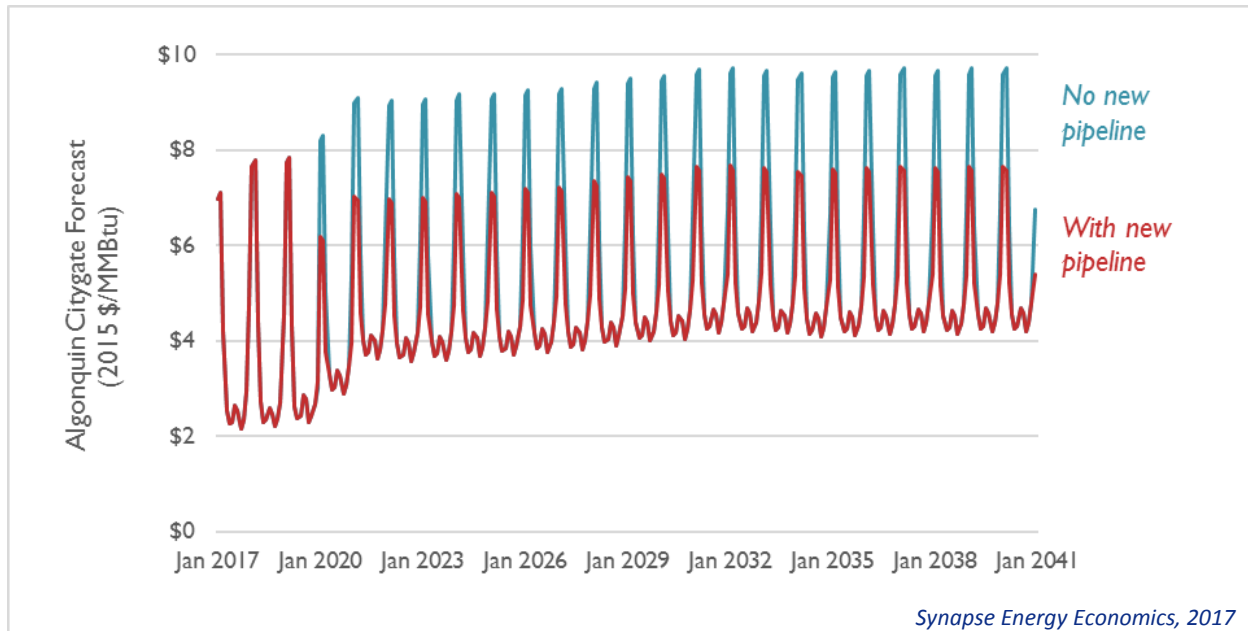
⁴⁷ NYMEX futures data is freely available at <http://www.cmegroup.com/trading/products/>

⁴⁸ Data for AEO 2017 can be found at <http://www.eia.gov/outlooks/aeo/>



the Mid-Atlantic region). Using NYMEX futures data for TETCO M3, we repeated the methodology for calculating the baseline Algonquin Citygate price. We then added a price adder of 3 percent to 5 percent to this TETCO M3 forecast to reflect variable pipeline costs charges.⁴⁹ This separate price trajectory was used in place of the main Algonquin Citygate price in every December, January, February, and March from December 2019 to December 2040 (see Figure 17).

Figure 17. Forecast of natural gas prices for Algonquin Citygate, with and without the Access Northeast pipeline



Note that this price forecast does not take into account possible price changes that could occur independent of Access Northeast pipeline project, including the price effects associated with the completed AIM expansion pipeline project or the proposed Tennessee Gas Pipeline – Connecticut Expansion, or the Atlantic Bridge pipeline projects.

Natural gas-fired generating units in EnCompass are modeled as receiving fuel from one of several delivery points, each of which has a different cost profile. Algonquin Citygate was assumed to be the delivery point for all units in the region, with the following exceptions: the Mystic combined-cycle plant in Massachusetts is assumed to receive LNG from the Everett terminal, and the Milford Power Plant and Bridgeport facilities in Connecticut are assumed to use the Iroquois delivery point.⁵⁰ As such, the Algonquin price impacts the delivered fuel costs of most of the fossil-fired units in New England, including in Connecticut.

⁴⁹ This variable price adder is composed mainly of fuel reimbursement charges.

⁵⁰ In addition, gas-fired units in Maine and New Hampshire are assumed to receive gas from the Dracut delivery point. However, Algonquin costs are used as a proxy for Dracut costs due to a lack of independent pricing data.

Natural gas pipeline costs

Spectra Energy, the developer of Access Northeast, has stated that they estimate the upfront capital cost of the Access Northeast pipeline project will be \$3.2 billion.⁵¹ However, the final cost of the pipeline will be much greater. This \$3.2 billion does not take into account operation and maintenance of the pipeline, depreciation expenses, property taxes, or income taxes. It also does not take into account return on equity of the pipeline, which often ranges from 10 to 14 percent. Once all these costs are levelized over a 20-year period (the time in which it takes the pipeline to fully depreciate), electric ratepayers may ultimately encounter an average annual gross cost of the pipeline to be \$0.5 billion per year.⁵² In present value terms, the total cost of the pipeline could be as high as \$6.6 billion for all New England electric ratepayers (see Table 14).

Table 14. Share of sales, annualized gross pipeline cost, and 20-year present value at a 5 percent discount rate. All values are in real 2015 million dollars.

	Share of Sales		Annualized Cost		Net Present Value	
	<i>Six-State</i>	<i>Four-State</i>	<i>Six-State</i>	<i>Four-State</i>	<i>Six-State</i>	<i>Four-State</i>
CT	25%	54%	\$129	\$284	\$1,608	\$3,542
MA	45%	0%	\$239	-	\$2,980	-
ME	10%	22%	\$52	\$115	\$648	\$1,429
NH	9%	0%	\$48	-	\$600	-
RI	6%	14%	\$34	\$74	\$418	\$921
VT	5%	10%	\$24	\$53	\$301	\$663
Total	100%	100%	\$526	\$526	\$6,555	\$6,555

⁵¹ More information on Access Northeast available at <http://www.accessnortheastenergy.com/FAQs/About-Access-Northeast/>

⁵² Petak testimony, page 20

APPENDIX D: REVIEW OF PREVIOUS PIPELINE STUDIES

Over the past two years, five consulting firms have released studies for different clients assessing the need for and potential benefits of developing new pipeline capacity in New England. The varied approaches and assumptions used in these studies have resulted in different, and often contradictory, conclusions. This report addresses the confusion associated with these contrasting results by identifying the underlying differences among the recent studies (see Table 15).

Table 15. New England pipeline studies released in 2015 and 2016

New England Pipeline Reports Released in 2015 or 2016	Link
London Economics for Maine Public Utilities Commission: <i>Maine Energy Cost Reduction Act: Cost Benefit Analysis of ECRC Proposals in the Context of a Regional or Multi-State Gas Pipeline Expansion Effort.</i> February 2016.	https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={484B2428-96C8-4D33-BCFE-9644318DA32A}&DocExt=pdf
Black & Veatch for National Grid: <i>Evaluation of Long-term Economic Benefits from Proposed Incremental Energy Infrastructure into New England.</i> January 2016.	http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=16-05%2fInitial_Filing.pdf
ICF for Eversource: <i>Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England Consumers.</i> December 18, 2015.	http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2finitial_filing_part3of3_Petak_.pdf
Analysis Group for Massachusetts Attorney General: <i>Power System Reliability in New England.</i> November 2015.	http://www.mass.gov/ago/docs/energy-utilities/reros-study-final.pdf
Synapse for Massachusetts Department of Energy Resources: <i>Massachusetts Low Gas Demand Analysis.</i> January 2015.	http://synapse-energy.com/sites/default/files/Massachusetts%20Low%20Demand%20Final%20Report.pdf

Based on our review of the key differences across the recently released New England pipeline studies, we make the following recommendations regarding assumptions to be used in any future studies:

- Future electric demand should be modeled based on up-to-date forecasts and should account for energy efficiency savings required by legally binding Energy Efficiency Resource Standards.
- Modeling should account for the impact of all renewable portfolio standards, as well as recent Massachusetts legislation that requires the state’s utilities to sign long-term contracts for 9.45 terawatt-hours of new renewable generation.
- All binding emission reduction requirements associated with the Clean Power Plan, Regional Greenhouse Gas Initiative, and state-level Global Warming Solution Acts should be accurately modeled.
- Rules recently adopted by ISO New England to increase winter electric reliability in New England should be accounted for.



Background

Whether there is value in building more natural gas pipeline infrastructure in New England is a question that has received a great deal of attention in the past few years. This is in part due to recent high-profile efforts to develop new pipeline capacity to serve New England, such as the proposed Access Northeast (ANE) and Northeast Energy Direct (NED) projects. Novel efforts by electric distribution companies (some of which share ownership of these new pipelines) to charge electric ratepayers for pipeline development costs have sparked a particular interest in the price effects of incremental pipeline capacity on New England electric consumers.

Just in the past two years, several studies have assessed the costs and benefits of developing new pipelines to serve New England. However, these studies have asked slightly different questions and taken varying approaches. These include investigating power system reliability in a future without a pipeline, evaluating the costs or benefits of a pipeline, and comparing a pipeline's net benefits against other alternatives. Each study has also made different—and often insufficient—assumptions on certain key points, including sales growth, unit retirements, renewable and energy efficiency standards, and greenhouse gas (GHG) reduction legislation. It is therefore unsurprising that they have produced different, and often contradictory, results. This paper summarizes the New England pipeline studies that have been published since the start of 2015, identifies several of the underlying differences that drive these studies' differing results, and concludes with some observations regarding the assumptions and constraints that a pipeline modeling exercise should contain. Table 15 (above) identifies the five studies that this review examines.

This document was originally published in November 2016 as a standalone document titled “New England Pipeline Studies Review” and is a follow-up to the February 2016 Synapse Energy Economics white paper *Sorting Out New England's Pipeline Needs* authored by Pat Knight and Elizabeth A. Stanton, PhD.⁵³

Study overviews

Table 16 summarizes the approach and findings of each of the major New England pipeline studies published in 2015 and 2016. The rest of this section further describes the methodology, key assumptions, and findings of each of these studies.

⁵³ *Sorting out New England's Pipeline Needs* is available at www.synapse-energy.com/sites/default/files/Sorting-Out-New-Englands-Pipeline-Needs.pdf.



Table 16. Approaches and findings of recent New England pipeline studies

Study Author and Lead Funder	Approach	Main Findings
London Economics for Maine Public Utilities Commission	Assessed costs and benefits to Maine of procuring new pipeline capacity.	Purchasing new pipeline capacity is only cost-effective for Maine if a new LNG export facility is built in Eastern Canada.
Black & Veatch for National Grid	Evaluated costs and benefits to New England electric consumers of developing ANE and NED projects, relative to a no-pipeline case.	ANE and NED, both separately and in conjunction, would generate over \$1 billion in annual net benefits for New England electric consumers.
ICF for Eversource	Assessed costs and benefits to New England electric consumers of developing the ANE project relative to a future with no pipeline.	ANE would generate annual net benefits between \$0.9 billion and \$1.3 billion.
Analysis Group for Massachusetts Attorney General	Examined need for incremental pipeline in New England, compared costs of pipelines to alternative strategies, and assessed compliance with emission reduction goals.	Power system reliability is maintained without new pipelines or other policies in base case. Expanding energy efficiency programs and purchasing Canadian hydroelectricity lead to savings relative to both a base case and a pipeline case. No modeled scenarios fully achieve emission reduction goals.
Synapse for Massachusetts Department of Energy Resources	Examined general need for pipeline in Massachusetts, compared costs of building a pipeline to alternative strategies, and evaluated compliance with emission reduction goals in Massachusetts.	Incremental pipeline capacity is needed in all modeled scenarios. Implementing alternative strategies alongside incremental pipeline is more expensive than just building pipeline. No modeled scenarios comply with emission goals.

February 2016 London Economics Study for Maine Public Utilities Commission

Research Questions and Methodology

In February 2016, London Economics International LLC (LEI) published a study on behalf of the Maine Public Utilities Commission (PUC) staff, in which it assessed the costs and benefits of Maine procuring new natural gas pipeline capacity in conjunction with other New England states.⁵⁴ LEI modeled the economic impacts for Maine of investing in natural gas pipeline relative to two base scenarios: one in

⁵⁴ Frayer, J. and M. Fagan. 2016. *Maine Energy Cost Reduction Act: Cost Benefit Analysis of ECRC Proposals in the Context of a Regional or Multi-State Gas Pipeline Expansion Effort*. London Economics International LLC. Available at <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={484B2428-96C8-4D33-BCFE-9644318DA32A}&DocExt=pdf>.



which a Liquefied Natural Gas (LNG) export facility is built in Eastern Canada, and another in which no new LNG export facility is built.⁵⁵

Key Assumptions

As is done in all forward-looking modeling exercises, LEI made a variety of assumptions regarding key inputs to its analysis. Some of the more significant assumptions that LEI made include:

- Electric demand: No direct forecasts of electric demand are provided. However, New England electric-sector demand for natural gas declines by 0.9 percent per year over the 2015-2030 study period.
- Natural gas demand: Residential natural gas demand increases at an annual rate of 1.8 percent; commercial natural gas demand increases at an annual rate of 1.1 percent.
- Natural gas prices: Baseline gas prices increase at a nominal rate of 3 percent per year.
- Power plant retirements: 3,288 MW of New England capacity retires between 2016 and 2030.
- Modeled renewable energy targets: All six New England Renewable Portfolio Standards (RPS) are met.
- Modeled GHG emission reduction standards: Carbon dioxide emissions are restricted by Regional Greenhouse Gas Initiative (RGGI) caps, and Clean Power Plan (CPP) requirements are met through RGGI compliance. Emission restrictions associated with state-level Global Warming Solution Acts (GWSAs) are not discussed.

Results

LEI finds that purchasing new pipeline capacity generates positive net benefits for Maine only if a new LNG export facility is built. If a new, costly LNG export is not built, a pipeline would not produce net benefits for the state. This is because increased LNG exports would both increase regional demand for pipeline natural gas (the export terminal would be served by pipelines) and decrease imports of natural gas to Maine from Canada. Both of these effects would lead to decreased natural gas prices and therefore greater pipeline-associated cost savings to Maine consumers. LEI further concludes that larger pipeline projects would generate larger economic impacts, with the direction of those impacts determined by whether the LNG export terminal is built.

⁵⁵ This facility would be an addition to the import facility already located in New Brunswick.

January 2016 Black & Veatch Study for National Grid

Research Questions and Methodology

In January 2016, Black & Veatch published a study for National Grid in which it evaluated two proposed natural gas infrastructure projects, NED and ANE.⁵⁶ Black & Veatch modeled the economic benefits to New England electricity consumers of three scenarios: one in which both ANE and NED are built, one in which only ANE is developed, and one in which NED alone is built.⁵⁷ Black & Veatch compared all three of these scenarios to a base case scenario.

Key Assumptions

- Electric demand: No direct forecasts of electric demand are provided. Natural gas demand for power generation grows at a rate of 0.8 percent per year.
- Natural gas demand: Residential gas demand grows at an annual rate of 1.1 percent; commercial demand grows at an annual rate of 1.4 percent.
- Natural gas prices: Base case New England natural gas average basis exceeds \$6 per MMBtu by 2025.
- Power plant retirements: 2,806 MW of New England fossil fuel and nuclear capacity retires between 2016 and 2030.
- Modeled renewable energy targets: It is unknown whether this report made any assumptions regarding RPSs.
- Modeled GHG emission reduction standards: It is unknown whether this report made any assumptions regarding GHG emission reduction requirements—there is no discussion of the CPP, RGGI, or GWSAs in this report.

Results

Black & Veatch concludes that ANE would have significant net economic benefits for New England electric consumers. Black & Veatch estimates that the ANE project would reduce average wholesale electricity prices by \$10.85 per MWh and provide \$1.1 billion in annual net benefits to New England electric ratepayers between 2019 and 2038. However, Black & Veatch's ability to successfully model a

⁵⁶ Black & Veatch. 2016. Evaluation of Long-Term Economic Benefits from Proposed Incremental Energy Infrastructure into New England. MA D.P.U. 16-05. Exh NG-JNC-3.

⁵⁷ In April 2016, NED's developer announced that it had canceled the project. This review therefore does not focus on analyses of the NED proposal. See Kinder Morgan. April 20, 2016. Form 10-Q: Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the Quarterly Period Ended March 31, 2016. P. 9. Available at http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/report/additional/KMI-03_31_2016-10Q_with_exhibits.pdf.



base case without the ANE indicates that New England will be able to maintain power system reliability in the absence of additional pipeline capacity.

December 2015 ICF Study for Eversource

Research Questions and Methodology

In December 2015, ICF International published a report assessing the proposed ANE pipeline expansion project on behalf of Eversource, one of the ANE developers.⁵⁸ ICF focused on the question of how the ANE project would affect New England natural gas and electric markets, and ultimately New England electricity consumers.⁵⁹ ICF sought to answer this question by modeling two alternative scenarios, with the only difference being that the ANE is built in one scenario but not the other.

Key Assumptions

- Electric demand: Electric load net of energy efficiency (EE) and passive demand response (DR) is nearly flat over the study period, growing at an annual rate of 0.04 percent over the 2016-2035 study period, based on ISO New England's 2015 CELT report.
- Natural gas demand: Residential and commercial natural gas demand grows an annual rate of 1.3 percent over the study period.
- Natural gas prices: Base scenario peak monthly average gas price increases from less than \$15 per MMBtu in 2016 to more than \$30 per MMBtu in 2030, an average annual increase of 5 percent.
- Power plant retirements: 4,150 MW of New England capacity retires between 2016 and 2030.
- Modeled renewable energy targets: All New England RPSs are met, but the Massachusetts RPS appears to have been inaccurately modeled as peaking at 15 percent of sales in 2020, rather than continuing to grow at a rate of 1 percentage point per year indefinitely.
- Modeled GHG emission reduction standards: Electric generators face a carbon price, but ICF does not discuss whether it models binding federal, regional, and state-level carbon emission reduction standards, such as the CPP, RGGI, and GWSAs.

Results

ICF and Eversource conclude that the ANE project would significantly depress natural gas prices, reducing them by an average of \$1.30 per MMBtu between 2019 and 2035. ICF estimates that these

⁵⁸ ICF International. 2015. Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England Consumers. MA D.P.U. 15-181: Exhibit EVER-KRP-3. December 18, 2015.

⁵⁹ Ibid, page 4.

reduced natural gas prices would drive wholesale electric prices down by between \$6 per MWh and \$10 per MWh, depending on the year. The reduced electric prices would in turn result in annual average savings of \$1.1 billion. ICF concludes that the combination of these electricity savings and reduced gas price volatility would generate gross savings of \$1.4 billion to \$1.9 billion per year, and annual net savings of between \$0.9 billion and \$1.3 billion, for New England electric customers. ICF's ability to successfully model a base case without the ANE indicates that New England will be able to maintain power system reliability in the absence of additional pipeline capacity.

November 2015 Analysis Group Study for the Massachusetts Attorney General

Research Questions and Methodology

In November 2015, Analysis Group, Inc. (AGI) published a report on behalf of the Massachusetts Office of the Attorney General in which it assessed the impacts of alternative strategies for addressing potential future electric reliability deficiencies in New England.⁶⁰ Unlike ICF and Black & Veatch, AGI did not compare a specific proposed pipeline project to a base case, but instead assessed the electric ratepayer net benefits and GHG emissions associated with several alternative resource strategies, including building a generic new pipeline. The scenarios assessed by AGI include one that involves the construction of new natural gas pipeline capacity; one that features expanded investment in LNG imports; one that relies on expanded EE and DR; one that involves a combination of expanded EE, DR, and contracts for hydroelectricity imports over existing transmission lines; one that includes a combination of expanded EE, DR, and contracts for hydroelectricity imports over new transmission lines; and one in which no new policies are implemented.

Key Assumptions

- Electric demand: Electric load net of EE and passive DR grows at an annual rate of 0.04 percent, based on ISO New England's 2015 CELT report.
- Natural gas demand: Non-electric gas demand increases at a rate of 1.4 percent per year.
- Natural gas prices: Peak month average Algonquin City Gates natural gas prices increase from \$8 per MMBtu in 2020 to \$11 per MMBtu in 2030, an annual increase of 3 percent.
- Power plant retirements: Between 2015 and 2020, 1,231 MW of coal capacity, 1,299 MW of nuclear capacity, and 1,226 MW of oil and gas capacity retire in New England.
- Modeled renewable energy targets: All six New England RPSs are met.

⁶⁰ Hibbard, P. J. and C. P. Aubuchon. 2015. *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*. Analysis Group, Inc. Available at <http://www.mass.gov/ago/docs/energy-utilities/eros-study-final.pdf>.

- Modeled GHG emission reduction standards: All scenarios are required to comply with CPP and RGGI emission caps, and the RGGI caps decline by 2.5 percent per year. GWSA targets are estimated but are not treated as binding constraints.

Results

AGI finds that under its base case assumptions power system reliability is maintained over time even in the absence of any new pipeline capacity or other policy action. AGI further concludes that, even under sensitivities in which reliability deficiencies emerge, investing in EE and DR is more cost-effective and more consistent with existing emission reduction laws than increasing pipeline capacity. AGI's EE/DR scenario saves \$85 million per year and reduces GHG emissions by 1.94 million metric tons (MMT) per year relative to its pipeline construction scenario. In addition, AGI estimates that investing in a combination of EE, DR, and hydroelectricity imports saves \$37 million per year and 4.94 MMT per year of GHG emissions relative to investing in new pipeline capacity. Nonetheless, each of AGI's scenarios falls short of fully meeting New England's state-level emission reduction goals.

January 2015 Synapse Study for the Massachusetts Department of Energy Resources

Research Questions and Methodology

In January 2015, Synapse Energy Economics (Synapse) published a study on behalf of the Massachusetts Department of Energy Resources in which it examined the need for new gas pipeline in Massachusetts, compared the costs of building new pipeline to alternative resource strategies, and evaluated compliance with Massachusetts' emission reduction goals.⁶¹ Synapse modeled eight scenarios, which feature varying levels of electricity demand, natural gas prices, and hydroelectricity imports from Canada. In each scenario, new pipeline capacity is built to cover any shortfalls in natural gas supply.

Key Assumptions

- Electric demand: Electricity demand net of EE increases at an annual rate of 0.1 percent per year in scenarios with low efficiency levels and *decreases* at a rate of 0.2 percent per year in scenarios with high efficiency levels.
- Natural gas demand: Non-electric natural gas demand net of EE *decreases* at an annual rate of 0.2 percent.
- Natural gas prices: Reference Henry Hub natural gas prices increase from \$4 per MMBtu in 2016 to \$6 per MMBtu in 2030, an average increase of 3 percent per year.
- Modeled renewable energy targets: All six New England RPSs are met.

⁶¹ Stanton, E. A. et al. 2015. *Massachusetts Low Gas Demand Analysis: Final Report*. Synapse Energy Economics. Available at <http://synapse-energy.com/sites/default/files/Massachusetts%20Low%20Demand%20Final%20Report.pdf>.



- Modeled GHG emission reduction standards: A carbon dioxide price forecast based on RGGI compliance prices is used, but no binding GHG emission reduction standards are modeled.

Results

Synapse concludes that incremental pipeline capacity of between 0.6 Bcf per day and 0.9 Bcf per day is needed to meet natural gas demand in all of its modeled scenarios. Synapse also finds that implementing alternative strategies such as EE and hydroelectricity imports results in increased net costs but diminishes the need for new pipeline infrastructure. However, none of the scenarios that Synapse models are fully compliant with Massachusetts' emission reduction goals.

Other Studies

February 2015 ICF Study for Eversource

In February 2015, ICF published an earlier version of its December 2015 study assessing the economic impacts of the ANE project on behalf of Eversource.⁶² This earlier report asks the same question, makes similar assumptions, and produces similar results as the subsequent December 2015 report. The February 2015 report, based on slightly different parameters, concludes that ANE would save New England electric customers between \$780 million and \$1.2 billion per year over the first 10 years of operation. This is a slightly lower estimate than the one contained in ICF's December 2015 report.

June 2015 LEI Study for Maine PUC

In June 2015, LEI published a prior version of its January 2016 study evaluating the economic benefits to Maine of contracting for incremental natural gas pipeline infrastructure.⁶³ The core difference between the two studies is that the initial June 2015 version assumed that Maine would have to bear the costs of any new pipeline capacity alone, rather than sharing the costs with the other New England states. Given this assumption, LEI concluded that investing in increased pipeline capacity was not economical under any scenario it modeled.

September 2015 ICF Study for Kinder Morgan

In September 2015, ICF published a study in which it assessed the need for, and economic impacts of, the proposed NED pipeline project.⁶⁴ ICF concluded that incremental pipeline capacity was needed to

⁶² ICF International. 2015. Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England. Available at www.accessnortheastenergy.com/content/documents/ane/Key_Documents/ICF-Report-on-Access-Northeast-Project1.pdf.

⁶³ Frayer, J. and M. Fagan. 2015. *Maine Energy Cost Reduction Act: Cost Benefit Analysis of ECRC Proposal*. London Economics International LLC. Available at <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={3FF03959-6F22-496F-BFC5-FC38D2BB9336}&DocExt=pdf>.

⁶⁴ ICF International. 2015. New England Energy Market Outlook: Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project.



address projected New England gas supply deficits, and that NED could save New England electric consumers between \$2.1 billion to \$2.8 billion per year under normal weather conditions.

June 2012 and November 2014 ICF Studies for ISO New England

In June 2012, ICF published a report that assessed the adequacy of New England's existing natural gas pipeline infrastructure to serve the region's growing demand for gas.⁶⁵ In November 2014, ICF published an updated analysis of New England's need for incremental pipeline infrastructure, which accounted for new pipeline projects and revised capacity estimates for existing pipelines.⁶⁶ Both analyses concluded that New England would face natural gas supply deficits by the winter of 2020 under all modeled scenarios, in direct contradiction to the ICF reports developed on behalf of Eversource.

Recommendations for comprehensive analysis

The use of reasonable, up-to-date assumptions would go a long way toward resolving many of the contradictory conclusions that past studies have reached. Some of the more important assumptions that this report and any New England pipeline assessments should pay close attention to include:

- Electric demand: The 2016 ISO New England CELT report forecasts that New England electric demand net of EE and DR will decline at an annual rate of 0.25 percent over the coming decade.⁶⁷ It is worth noting that the ISO-NE's load forecasts have gotten progressively lower over the past five years, as actual load has consistently fallen below forecasted levels. Therefore, the -0.25 percent glide path should likely be taken as the upper bound of New England's load growth trajectory. In addition, any comprehensive study should incorporate load reductions associated with legally binding Energy Efficiency Resource Standards, the savings of which are often not adequately accounted for in ISO-NE's forecasts.⁶⁸
- Natural gas demand: Forecasts of non-electric natural gas demand should account for the most up-to-date regional heating demand forecasts, such as those from local distribution companies and industrial customers. These forecasts should take into account the likely impacts from end use energy efficiency, state mandates to reduce greenhouse gas emissions, and market trends for fuel switching.

⁶⁵ ICF International. 2012. Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs. Available at <http://psb.vermont.gov/sites/psb/files/docket/7862relicense4/Exhibit%20EN-JT-15.pdf>.

⁶⁶ ICF International. 2014. Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II. Available at https://iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf

⁶⁷ ISO New England. 2015. Forecast Report of Capacity, Energy, Loads and Transmission (CELT) 2016-2025. Available at www.iso-ne.com/static-assets/documents/2016/04/isonne_fcst_data_2016.xls.

⁶⁸ For more information on how the ISO could better account for energy efficiency and distributed PV in its forecasts, see http://www.synapse-energy.com/sites/default/files/Challenges-for-Electric-System-Planning_0.pdf.



- Natural gas prices: If using exogenous inputs for natural gas prices, base-case forecasts of future natural gas prices should be based on or in line with widely accepted sources, such as the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2017 or NYMEX futures. The AEO 2017 forecast suggests that the natural gas price for New England electric power generators is likely to grow at an annual rate of 2.9 percent between 2017 and 2030.⁶⁹ Alternatively, if using dynamic gas modeling, up-to-date assumptions for recent pipeline infrastructure additions and LNG deliveries should be used.
- Modeled renewable energy targets and imports: All six of New England's state renewable portfolio standards should be modeled accurately. In addition, any comprehensive analysis should account for the impact of recent Massachusetts legislation that requires the state's utilities to contract for 9.45 TWh of imports of large hydroelectric generation that are in excess of the state's RPS.⁷⁰ Care should also be taken to accurately model likely future imports of electricity from neighboring regions, above and beyond what should be included as part of the Massachusetts large hydroelectric procurement.
- Wind, solar, energy efficiency, and demand response prices: The latest information on recent projects and expected trends for prices should be used to forecast costs associated with renewables (wind, utility-scale solar, and distributed solar), energy efficiency, and demand response. Costs of these resources have declined in recent years and are expected to continue decreasing in the future. Using out-of-date cost information can significantly skew costs of scenarios which rely on greater quantities of these resources.
- Other electric system additions and retirements: In addition to adequately modeling new renewable energy targets, comprehensive analysis should also account for already-announced retirements and additions of conventional generation, including coal, natural gas, and nuclear units.
- Modeled GHG emission reduction standards: Any comprehensive analysis should model binding GHG emission caps associated with RGGI, the CPP, and state-level GWSAs. Given the uncertainty around precise sector-specific caps under the state GWSAs, robust studies should identify a set or range of likely compliance pathways.

⁶⁹ U.S. Energy Information Administration. 2017. Annual Energy Outlook 2017. Available at <http://www.eia.gov/outlooks/aeo/>

⁷⁰ Massachusetts House Bill No. 4568. 2016. Available at <https://malegislature.gov/Bills/189/H4568/BillHistory>.

- Other rules and regulations: In the last three years, ISO New England has adopted regulatory changes designed to increase electric reliability in New England, including a short-term Winter Reliability Program⁷¹ and a long-term Performance Incentives structure.⁷² Any comprehensive analysis should account for these new rules in order to avoid over-stating potential reliability issues in the region.

Finally, as is done in this report, any other comprehensive analysis of the potential impacts of investing in natural gas pipeline capacity in New England should compare a pipeline construction scenario to a reasonable array of alternative scenarios. This means evaluating scenarios that include greater investment in renewable energy resources and energy efficiency—and using reasonable assumptions regarding the costs of these alternative resources—rather than simply comparing a pipeline scenario to a base case in which alternative resource investment remains limited.

⁷¹ ISO New England. 2016. ISO New England Inc. Transmission, Markets, and Services Tariff, Section III, Appendix K.

⁷² ISO New England. 2016. FCM Performance Incentives Key Project. Available at <https://www.iso-ne.com/committees/key-projects/fcm-performance-incentives>.