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# The Economic Impacts of Failing to Build Energy Infrastructure in New England

**Prepared for:** New England Coalition for Affordable Energy

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# EXECUTIVE SUMMARY

New England has among the highest natural gas and electricity prices in the U.S., a distinction that is increasingly being driven by inadequate energy infrastructure. In fact, energy infrastructure constraints have reportedly cost the region at least $7.5 billion over the past three winters alone.[1]

Since 2000, New England's reliance on natural gas to generate electricity has increased dramatically and is now used to fuel over 40% of the region's generation, which determines electricity prices a majority of the time.[2] Pipeline infrastructure has not kept pace with this increased demand and is reaching maximum capacity, especially during the winter months, to meet both electricity generation and space heating demands.

Regional environmental policies and federal environmental requirements are contributing to decisions to retire older generating plants. These anticipated retirements will require replacement generation. This replacement generation is expected to be primarily powered by natural gas and wind, which will in turn require expanded natural gas pipeline capacity and new transmission lines to move electricity to and within the region.

Underinvestment in infrastructure due to external constraints[3] ensures persistent and increasing energy prices and costs for the region. Such costs make it difficult for businesses to maintain competitiveness, which undermines the region's ability to retain and attract jobs. In addition, higher costs reduce disposable income for families, affecting their quality of life.

The economic consequences of failing to build natural gas and electricity infrastructure to serve New England's energy needs over the next five years (2016 to 2020) can be characterized in three ways: the cost of electricity and natural gas, the region's employment, and disposable income.

In conducting this study, two energy infrastructure cases were considered: 1) a constrained case wherein no new investments are made to expand infrastructure beyond today's levels; and 2) an unconstrained case wherein investments are made leading to new and expanded natural gas and electricity infrastructure at levels sufficient to mitigate or avoid higher prices and related impacts.

While prior studies have examined specific types of infrastructure, this one is more comprehensive in that it includes multiple types of energy infrastructure.

**Lack of new energy infrastructure will cost the region $5.4 billion in higher energy costs**

Failing to expand the region's energy infrastructure will cost New England households and businesses $5.4 billion in higher energy costs (in 2014 dollars) between 2016 and 2020. The $5.4 billion in added costs

[1] See "N.E. Governors Change Course On Paying For Energy Projects," April 13, 2015, Hartford Courant.

[2] ISO-NE. See http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix

[3] These constraints are external to the market, since market prices are providing signals to develop infrastructure and projects have been proposed by infrastructure developers.

will ramp up from 2016 through 2020, increasing the region's electricity and natural gas costs by 9 percent in 2020 according to forecasted energy demand and costs. [4] Similar or larger impacts can be expected beyond 2020 if infrastructure is not added as demands for natural gas and renewable electricity increase.

**Higher energy costs will lead to the loss of 52,000 private-sector jobs[5]**

Between 2016 and 2020, the region will lose a total of 52,000 temporary or permanent private-sector jobs due to higher energy costs. In 2020 alone, when the energy cost escalation is the largest, the New England economy will lose 25,600 private-sector jobs. This negates 80 percent of the private-sector job growth predicted for the region for that year by the REMI model used in this report.

Job losses will come predominantly from the following sectors: construction, retail, trade, healthcare, restaurants/hotels, manufacturing and professional and technical services, indicating a wide impact across a variety of economic sectors.

**Lack of energy infrastructure will reduce household spending by $12.5 billion**

The consequences of not investing in the energy infrastructure modeled in the study will lead to a total cumulative loss in gross regional product (GRP) of $16.1 billion between 2016 and 2020 - $8.5 billion from infrastructure disinvestment and $5.6 billion from higher energy costs - $12.5 billion of which is comprised of lost personal income.

Because the timeframe for the study is so short – only through 2020 – the economic impacts from foregone construction activity and higher energy costs from lack of investment in energy infrastructure were combined.

**$9 billion in foregone construction activity results in a loss of 115,600 jobs**

An infrastructure investment of $9 billion was estimated to build out the infrastructure in the unconstrained case between 2016 and 2019 for natural gas piplines, electric transmission lines, and renewable and non-renewable electricity generation. For New England, the job consequences of under-investing in energy infrastructure projects by this amount leads to an average annual loss of 28,900 jobs in the private-sector between 2016 and 2019 – or a total of 115,600 jobs temporarily or permanently lost over that timeframe. It is not surprising that the largest share of jobs affected are in the construction sector. Other sectors are implicated through involvement in the supply-chain of these infrastructure projects, or by the economic multiplier effects that are catalyzed when economic activity changes and household earnings are affected.

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[4] $5.4 billion of increased energy costs will be incurred by the region's consumers if infrastructure is not expanded by the levels modeled in the unconstrained case. This takes into account the costs consumers save by not building infrastructure – estimated at $2.6 billion over the study period

[5] This study combined two interpretations to define a "job lost": (i) it may include the loss of an existing job, or (ii) it may reflect a "slower addition" or growth of new positions over the period of 2016 through 2020. Finally, the job impacts discussed in this report are a combination of full and part-time positions.

The study was conducted by a Boston-based team of experts with extensive experience in energy markets and pricing, and economic impact analysis.

La Capra Associates is a consulting firm that has specialized in the electric and natural gas industries for 35 years. The firm's expertise includes power market policy and analysis (wholesale, retail, and renewable), power procurement, power resources planning, economic/financial analysis of energy assets and contracts, and regulatory policy.

Economic Development Research Group, Inc. (EDR Group) specializes in applying state-of-the-art tools and techniques for evaluating economic impacts and opportunities associated with investment and policy changes. The firm was started in 1996 by a core group of economists and planners who are specialists in evaluating impacts of energy, environment and transportation programs and policies on economic development opportunities.

# 1. INTRODUCTION AND OVERVIEW

The New England Coalition for Affordable Energy ("the Coalition") retained La Capra Associates, Inc. ("La Capra") and Economic Development Research Group ("EDR Group") to conduct an independent, objective study of the economic consequences of constrained investment in natural gas and electricity infrastructure to serve New England's energy needs over the next five years.

New England has among the highest natural gas and electricity prices in the U.S., a distinction that is being driven by inadequate energy infrastructure. In fact, energy infrastructure constraints have reportedly cost the region at least $7.5 billion over the past three winters alone.[6]

Since 2000, New England's reliance on natural gas to generate electricity has increased dramatically and is now used to fuel more than 40% of the region's generation;[7] more importantly, natural gas prices determine electricity prices a majority of the time. In addition, of the 12,000 MW of new generation proposed for the region, 66% is natural gas and 33% is wind.[8] Pipeline infrastructure has not kept pace with this increased demand and is reaching maximum capacity, especially during the winter months, to meet both electricity generation and space heating demands.

Regional environmental policies and federal environmental requirements are contributing to decisions to retire older generating plants. At least ten percent of the region's generating fleet has retired or is expected to retire over the 2013-2018 time period including major nuclear, coal, and oil resources. Other oil- and coal-fired generating facilities have also been identified to be at risk of retiring.[9] These expected and potential retirements will require replacement generation, which will in turn require expanded natural gas pipeline capacity and new transmission lines to move electricity to and within the region.

Constrained infrastructure investment ensures persistently high and increasing energy prices for the region. High energy costs make businesses less competitive, undermining the region's ability to retain and attract businesses, thereby hurting the job market. In addition, higher costs reduce disposable income for families affecting their quality of life. The study found the potential impacts of constraints on infrastructure investment could, over the next five years (2016 to 2020), lead to higher energy costs in the range of $5.4 billion (2014 dollars), lower personal income that could likely top $12 billion and job losses – temporary and permanent – that could be in the range of 167,000 over the same period.

[6] See "N.E. Governors Change Course On Paying For Energy Projects," April 13, 2015, Hartford Courant.

[7] ISO-NE. See http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix

[8] Ibid.

[9] 8,300 MW by 2020 according to ISO-NE.

# 1.1 STUDY APPROACH

The study was uniquely designed to assess the consequences of constraints[10] on investment in energy infrastructure in the region between now and the year 2020 on: 1) the cost of electricity and natural gas, 2) the region's employment, and 3) disposable income.

In conducting the study, two energy infrastructure cases were considered: 1) a constrained case wherein the region's infrastructure is not expanded beyond today's current levels; and 2) an unconstrained case wherein new and expanded natural gas and electricity infrastructure is included.

The study consisted of three tasks: 1) develop assumptions for each of the above cases; 2) conduct an analysis to quantify the differences in energy costs between the two cases and to estimate infrastructure investment costs; and 3) use a forecasting model to determine the broader economic impacts, specifically the impact on jobs, the economy and households.

While prior studies have examined specific types of infrastructure—notably, the expansion of the interstate natural gas pipeline system—this one is more comprehensive in that it includes multiple types of infrastructure, as natural gas and electricity are directly linked in New England due to the prevalence of natural gas as a generating fuel. As can be imagined, analysis of multiple infrastructure types can involve significant complexity, hence a series of realistic and defensible assumptions were established to capture the interactions among the different infrastructure systems.

# 1.2 INFRASTRUCTURE INVESTMENT (BUILDOUT) ASSUMPTIONS

The focus of the study was to review infrastructure investment primarily for economic purposes—to avoid increases in prices—rather than investments deemed to be needed solely for reliability purposes.

Four types of energy infrastructure were considered to potentially reduce energy prices by either increasing the deliverability of natural gas during constrained times or reducing the demand for natural gas by drawing electricity from non-gas-fired sources located outside or inside of New England.

Using publically available information, estimated levels of expansion were assumed for each infrastructure category below in units of megawatts (MW) of electricity generated or billion of cubic feet of natural gas delivered. No specific infrastructure projects were considered. The goal was not to present a project-by-project analysis, but to generically build up overall levels of infrastructure development that would reduce energy costs. The assumptions were based on the following, summarized in Table 1:

- ***Natural gas pipeline additions*** – This infrastructure is used both to transport natural gas from producing regions from outside of New England and within New England from the east, notably the liquefied natural gas ("LNG") facilities in the Boston area. The level and timeline of expansion was based on a review of proposed pipeline projects (in Appendix A), which were larger than what

10 These constraints are external to the market, since market prices are providing signals to develop infrastructure and projects have been proposed by infrastructure developers.

was modeled in this analysis. The specific levels used in this analysis, 1.7 Bcf/day of capacity, was based on a review of development efforts and the impacts of different expansion levels on prices.

- ***Transmission imports*** – Transmission infrastructure can be used to deliver electricity from neighboring regions, such as New York or Canada. The assumption to add 500 MW of transmission imports was based on one possible outcome of the joint procurement efforts currently underway by the three Southern New England states and taking into account the likelihood of such a project being operational by 2020.
- ***Renewable electric generation*** – Expansion of renewable generation is required to comply with individual state mandated goals to meet Renewable Portfolio Standard (RPS) requirements and thus avoid Alternative Compliance Payments (ACP) in each individual state. It was assumed that 1,360 MW of in-region wind generation would be added to the system.
- ***Non-Renewable electric generation*** – Generation expansion produces electricity but also contributes to meeting the region's "installed capacity" requirements ("ICR").[11] It was assumed that 920 MW of capacity cleared in the most recent ISO New England Forward Capacity Market from two new generating facilities under development would be added to the region's infrastructure.

TABLE 1: SUMMARY OF STUDY INFRASTRUCTURE ASSUMPTIONS (THROUGH THE YEAR 2020)

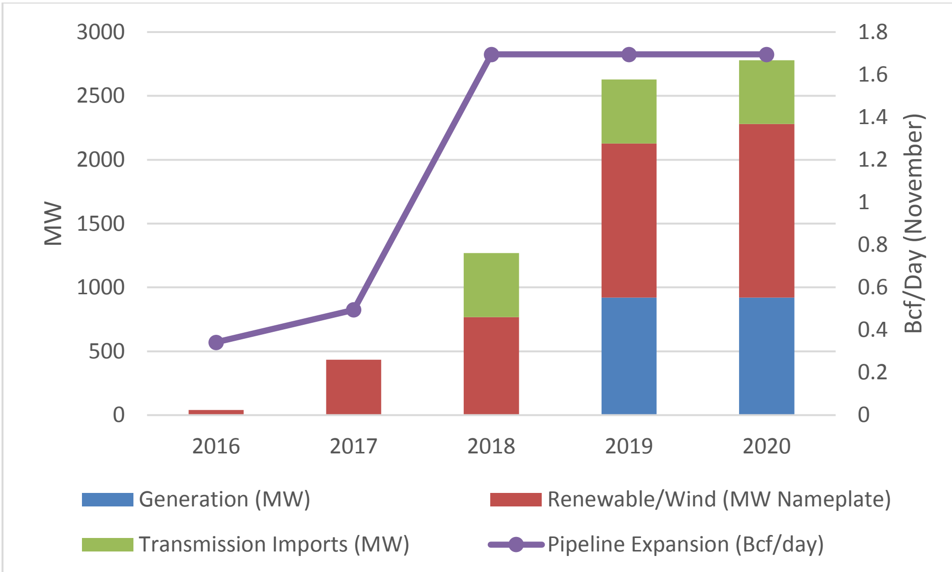
| **Infrastructure Type** | **Constrained Case (No New Infrastructure)** | **Unconstrained Case (New Infrastructure Added)** |
|---|---|---|
| Natural Gas Pipeline Additions | 3.9 Bcf/day constant[12], no pipeline additions | Additional supply of 1.7 Bcf/day from new pipeline(s) |
| Transmission Imports | None | 500 MW in June 2018 |
| Renewable Generation | None | 1,360 MW of new wind generation over the study period |
| Non-Renewable Electric Generation | None | 920 MW in June 2019 |

Figure 1 shows the expansion assumed in the unconstrained case over the study period. Note that natural gas pipeline expansion (shown in billion of cubic feet per day or "Bcf/day") was assumed in November of the year shown in the figure, and generation (shown in megawatts ("MW") of nameplate for wind and capability for other generation) was assumed to be available for the summer peaks in each year.

[11] The ICR measures the amount of resources (in megawatts) necessary to meet reliability standards.

[12] This represents a maximum value that was observed in the database of pipeline flows and was used in the modeling.

FIGURE 1: INFRASTRUCTURE EXPANSION – UNCONSTRAINED CASE




These energy units (MWs and Bcf/day) were modeled to determine the market price impacts of the infrastructure expansion. Price impacts were then translated to cost impacts for different customer groups, which were then used as inputs to an economic model developed to quantify the economic impacts of failing to expand infrastructure.

It is important to note that neither the constrained nor unconstrained cases represent a "base" case or most likely case, though the assumptions used to define the two cases are based on current developments in New England. The difference between the constrained and unconstrained cases can be specified in energy units (e.g., megawatts of electricity generated or cubic feet of gas delivered) over a specific time (hour, day, etc.) and can be referred to as an "infrastructure" gap. As mentioned previously, no value judgements were attached to the presence of a gap—differences between supply and demand are commonplace and can lead to changes on the part of market participants on both the demand and supply side. Gaps can also occur where reliability needs or policy goals have not been met, but these are not the focus of this study. Indeed, the region may be able to continue over the short term with the current buildout from a reliability perspective but, as discussed herein, this will occur at higher cost levels. These costs will impose a burden on households and businesses and will harm regional competitiveness.

## 1.3 ENERGY COST MODELING – INFRASTRUCTURE IMPACT ON ENERGY COSTS

A model that examined the relationship between natural gas prices in the region and infrastructure expansion was developed and used to study the impact of gas pipeline additions on New England natural gas prices and wholesale electricity prices in the form of locational marginal prices ("LMPs")[13]. Key inputs to the model included: natural gas pipeline capacity, local distribution company ("LDC") natural gas demand[14], electric demand for natural gas, additional imports or renewable additions, and resources on the margin identified by ISO New England, the administrator of the region's wholesale electricity market. The model simulates summer and winter scenarios as well as scenarios for adding pipeline and transmission capacity.

A Monte-Carlo simulation, involving 10,000 trial runs, was conducted and several key variables were modeled as distributions rather than as fixed values in the simulation. The variables modeled as distributions were LDC pipeline demand, electric demand for gas and gas basis price. Cost impacts from the infrastructure cases were estimated for four customer segment groups – residential, commercial, industrial, and government – and included:

- natural gas costs
- electricity costs due to energy and capacity market changes
- electricity costs due to Renewable Portfolio Standards

Additional models were used to capture the impact of infrastructure expansion (or lack thereof) on other cost components, including electricity capacity costs and renewable energy costs.

In addition, because lack of infrastructure development also results in loss of economic activity from construction and operations and maintenance, the dollar amount of these activities was quantified to demonstrate the economic impacts of disinvestment for generating and transmission assets.

The energy cost modeling was specifically designed to isolate infrastructure to quantify its impact on prices. The analysis did not include:

- Costs related to public policy benefits such as energy efficiency and renewables or retail delivery charges by regulated electric and natural gas utilities.
- Infrastructure needs strictly from a "reliability" perspective or to meet certain policies (except for renewable portfolio standards). Indeed, infrastructure expansion (beyond what was modeled) may be required to meet certain reliability criteria as well as to meet environmental goals.[15]

Finally, the cost modeling did not consider a benefit-cost analysis of infrastructure options or project evaluation of specific projects. The five-year period considered in this study only accounts for a fraction

[13] Natural gas prices have significant impacts on electricity prices, because natural gas generation sets the LMPs during most of the year.

[14] LDC demand includes all customers that buy gas supply from the utility, including households and businesses.

[15] Environmental impacts of the infrastructure types were not examined. Though expansion of certain infrastructure types may change air emissions and have other environmental impacts, the amount of energy consumed was not explicitly changed relative to status quo assumptions. Rather, the focus was on the ability of infrastructure to deliver or provide similar amounts of energy at potentially lower prices.

of the useful life of most infrastructure types, and therefore there was no analysis of the various potential benefit and cost categories[16] that could be impacted by infrastructure expansion.

## 1.4 ECONOMIC IMPACT MODELING – INFRASTRUCTURE IMPACT ON THE ECONOMY

The economic consequences (employment and disposable income) of constrained or insufficient infrastructure investment were then quantified by using a dynamic, impact forecasting tool developed by Regional Economic Models, Inc. ("REMI").

REMI is an econometric model that simulates the various components of the regional economy and allows the examination of impacts of disturbances or shocks to the economy. For example, energy cost increases reverberate through households' ability to spend, and businesses' cost-of-doing business which affects production levels and their investment decisions. For this study, energy price impacts were studied separately and then translated into changes in costs as felt by different customer groups, such as residential and commercial (and industrial) customers.

The REMI model was selected because of its ability to examine price effects by customer segment and changes in competitiveness of commercial and industrial sectors in the region relative to other parts of the U.S.

By inputting the results of the energy cost analysis, the annual effects on jobs, dollars of gross regional product and household disposable spending were quantified and the sectors most implicated identified.

## 1.5 REPORT OVERVIEW

The remainder of this report is structured as follows:

- Energy Cost Analysis – describes the pricing analysis and results related to infrastructure expansion (or lack thereof). The prices, combined with forecasted consumption, were used to calculate the cost impacts for different customer segments. Unless otherwise stated, all costs are in 2014 dollars.
- Economic Impacts – features the discussion of the economic impacts of the cost impacts due to not building infrastructure. A dynamic annual impact forecasting model was used to gauge how the cost burden on residential, commercial, industrial and municipal energy customers alters the economy. The model was used to estimate macroeconomic impacts, such as job losses and dollars of gross regional product.

Detailed explanations and supporting data for key assumptions are included in separate, stand-alone Appendices that are highly detailed and technical.

[16] Examples include reduction in volatility, flexibility of supply sources, changes in regional industrial structure, and population.

The analysis was conducted by a Boston-based team of experts with extensive experience in energy markets and pricing, and economic impact analysis.

La Capra Associates is a consulting firm that has specialized in the electric and natural gas industries for 35 years. The firm's expertise includes power market policy and analysis (wholesale, retail, and renewable), power procurement, power resources planning, economic/financial analysis of energy assets and contracts, and regulatory policy.

Economic Development Research Group, Inc. (EDR Group) specializes in applying state-of-the-art tools and techniques for evaluating economic impacts and opportunities associated with investment and policy changes. The firm was started in 1996 by a core group of economists and planners who are specialists in evaluating impacts of energy, environment and transportation programs and policies on economic development opportunities.

# 2. ENERGY COST ANALYSIS

An analysis was conducted to quantify the increase in energy costs to the region if investment in energy infrastructure in New England is constrained between now and the year 2020. This analysis involved calculating the changes to natural gas and electricity costs associated with each type of infrastructure included in the unconstrained infrastructure investment case – natural gas pipeline additions, transmission imports, renewable generation, and non-renewable (natural gas-fired) electric generation. Cost impacts were then computed for four customer segments: residential, commercial, industrial, and government – which subsequently served as inputs to the economic modeling in Section 3 to quantify the impacts on the economy of higher energy costs from constrained energy infrastructure investment.

## 2.1 MODELING OVERVIEW

Given that the analysis involved examining different types of energy infrastructure, different methodologies were utilized to capture the interactions between lack of supply and costs. The infrastructure types discussed in this report impact different cost components, which involve different market mechanisms and modeling efforts.

### 2.1.1 *NATURAL GAS/LOCATIONAL MARGINAL PRICE MODEL OVERVIEW*

A "Monte-Carlo" simulation[17] model was utilized to study the impact of gas pipeline additions on New England natural gas prices that would be paid by natural gas customers. The model also calculated how these natural gas prices would influence the "energy" component of electricity prices. This approach was chosen in order to capture the impact of uncertain variables, such as weather and resource additions/retirements. The model can be run for summer (April through October) or winter (November through March) pipeline conditions. Calculating separate impacts for summer and winter is important, since most of the cost impacts from constrained natural gas infrastructure has occurred during the winter months. Additional detail regarding the model can be found in Appendix B.

The key to the model is the relationship between unused natural gas pipeline capacity or available space (headroom) and the natural gas basis price, which is the difference between the price at the primary New England delivery point (Algonquin Citygate) and the TETCO M-3 price (point reflecting the cost of Mid-Atlantic supply that serves northeast U.S. demands). The model first calculates pipeline headroom based on forecasted New England natural gas supply and demand. Then it uses the historical relationship between headroom and natural gas basis to predict the price of natural gas delivered to New England. The natural gas price is subsequently used to forecast changes in locational marginal prices ("LMPs"), which are wholesale electricity prices paid to resources to generate electricity ("energy") during the year.

Actual data from winter 2011-2012 to winter 2014-2015 was used to populate the model. This period includes two much colder than normal split (November to October) years (2013/14, 2014/15), one slightly

[17] Monte-Carlo analysis involves probabilistic of stochastic analysis to explain relationships among variables.

warmer than normal (2012/2013) and one much warmer than normal (2011/2012) year. Hence, the constrained supply conditions of the past two winters (as discussed in the Introduction) are reflected in the results below, but overall, the dataset reflects close to average (or normal) conditions.

### 2.1.2 *CAPACITY MARKET MODEL OVERVIEW*

For capacity market impacts, a separate model was used. This model simulates future capacity market auctions based on inputs from the latest completed forward capacity market ("FCM") annual auction and assumptions regarding resource changes and market trends. Price impacts of entry by generating units and other resources, such as renewable generation, energy efficiency, imports, and demand response, were calculated by changing the supply that would be used to meet the required level of resources to meet reliability standards. Additional detail can be found in Appendix C.

### 2.1.3 *RENEWABLE ENERGY CERTIFICATE MODEL OVERVIEW*

A third component of costs that is captured by the analysis is the cost to meet renewable portfolio standards, which consist of state-level requirements to purchase a certain percentage of electricity from renewable resources (as measured by generation of renewable energy certificates ("RECs")). The analysis of the REC price changes due to the presence or lack of infrastructure was performed by a supply/demand model (distinct from the two modeling efforts described above). The model uses publicly available regional load and system information from ISO New England, published information on renewable energy portfolio requirements in New England under current statute, and data on renewable resources already online to estimate REC market demand today and in the future.

A supply curve was created using the estimates of renewable potential and costs in the region. A market-clearing REC price was calculated for each year of the forecast period. Although total supply and demand are aggregated across Massachusetts, Connecticut, New Hampshire and Rhode Island Class I, the marginal REC was assumed to clear in the MA I market. Broker quotes were used for the first several years of the study period to ensure that the forecast was consistent with current market conditions. Additional detail on the renewable cost analysis can be found in Appendix C.

## 2.2 NATURAL GAS PRICES AND PIPELINE INVESTMENTS

Table 2 represents the increase in natural gas basis prices under the constrained infrastructure scenario (no new pipeline capacity addition through the year 2020) between the two cases for winter, summer and annually that was estimated by the modeling work. Basis[18] price differences on an annual basis were found by weighing the seasonal values.

[18] Basis is the difference between a price at a specific location and a reference price.

TABLE 2: NATURAL GAS BASIS INCREASE, CONSTRAINED CASE FOR WINTER, SUMMER AND ANNUAL ($/MMBTU)

| Season | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| Winter | n/a | $1.36 | $2.23 | $3.93 | $4.00 | $4.27 |
| Summer | n/a | $0.22 | $0.33 | $0.45 | $0.52 | n/a |
| Annual | $0.22 | $0.84 | $1.41 | $1.91 | $2.02 | n/a |

Without the addition of 1.7 Bcf/day of natural gas pipeline capacity[19] the model shows that basis prices will be higher by $2.02/MMBtu in 2020 and by $4.27/MMBtu for the winter of 2020/2021.

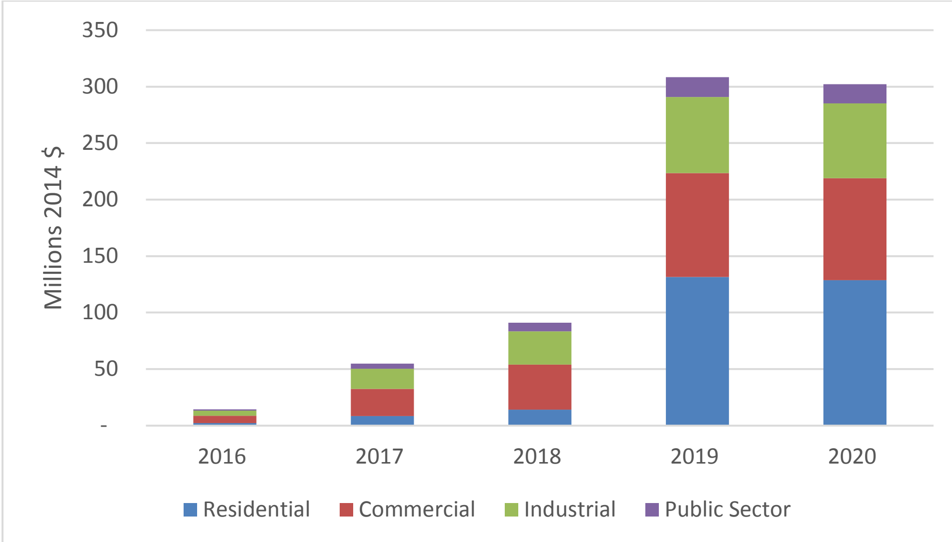
The modeling results above were based in part on the assumption that there would be impacts even in the summer months when pipelines are generally not congested. This result is consistent with the data in the historical period, which did feature positive differences between the Algonquin citygate prices and prices outside the region (as shown in the TETCO M-3 prices).

In order to calculate the impact on costs paid by natural gas customers (excluding use by generation facilities) in the region, the amount of throughput over the study period was forecasted. More importantly, the calculation also accounted for the portion of this throughput that would be impacted by changes in basis prices that were shown in the prior section. Natural gas customers in New England will be impacted by the basis reductions shown above to the extent that the gas used to supply their demands are priced at New England (or Algonquin citygate) prices. Where supplies are priced differently (as in the case of Vermont, which receives prices at the Canadian border) or feature supplies priced outside of New England close to production areas, then natural gas costs will not be impacted. Assumptions regarding the amount of natural gas usage that would be impacted by the price impacts can be found in Appendix C.

Figure 2 shows the annual increases to natural gas bills for the customer segments due to artificial constraints in pipeline delivery. In short, failure to expand pipeline infrastructure will lead to approximately $770 million in additional energy costs to the region from 2016 to 2020.

[19] The addition of transmission of imported energy and renewable expansion were also modeled, thus the results are net of these impacts.

FIGURE 2. NATURAL GAS COST INCREASE, CONSTRAINED CASE




## 2.3 ELECTRIC ENERGY MARKET IMPACTS

The wholesale natural gas price changes summarized in Table 2 were utilized to calculate the impacts on electric energy prices. In New England (and some other regions in the U.S.), it is important to distinguish between electric "energy" and electric "capacity" prices. Both are distinct "products" in the regional wholesale energy market. Energy refers to the generation of electricity over a specific period of time; it is the product that is consumed at the retail level. Capacity, on the other hand, is the amount of resources—including both supply (generation) and demand resources (energy efficiency and demand response)—available to generate electricity at a particular point in time. Both products are required purchases at the wholesale level and their costs are included in retail bills. Electric energy costs are impacted by the price of natural gas paid by generators and the entry of low-variable cost resources — this analysis examined the impact of pipeline and transmission infrastructure that would increase the importation of hydro- or wind power from outside of the region.

The model discussed above for natural gas also forecasts electric energy prices.[20] The model focuses on resources on the margin, which set locational marginal prices ("LMPs").[21] LMPs for summer and winter were calculated by multiplying the cost of electricity for resources on the margin by the amount of time

[20] The common way to estimate these impacts is to utilize a "production cost" or "dispatch" model that simulates the hourly production of energy by all the generating units (and other resources) in the region, and thus accounts for changes in generation costs due to fuel costs on such a granular basis. This approach was approximated by using the % of hours units were on the margin for different fuels and assumptions about "heat rates", which measure how much fuel is necessary for different generation types.

[21] Locational marginal prices ("LMPs") are determined by selecting the offer to supply the next increment of demand at specific times and for certain locations. These offers (or prices) are thus selected on a "marginal" basis and are most frequently from natural gas generators in New England.

that resource is expected to be on the margin. Table 3 summarizes the forecasted difference in LMPs[22] between the constrained and unconstrained infrastructure investment cases.[23]

TABLE 3: INCREASE IN LMPS RELATED TO NATURAL GAS INFRASTRUCTURE, CONSTRAINED CASE ($/MWH)

| Season | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Winter | n/a | $6.44 | $11.16 | $20.88 | $22.25 |
| Summer | n/a | $1.43 | $2.19 | $2.99 | $3.47 |
| Annual | $1.05 | $4.31 | $7.55 | $10.67 | $11.74 |

Without the addition of 1.7 Bcf/day of natural gas pipeline capacity, the model forecasts that LMPs will increase by $22.25/MWh for the winter of 2019/2020 and by $11.74/MWh for the calendar year 2020.

The addition of 500 MW of transmission that allows additional imports from neighboring regions has the potential to impact the electricity prices and costs paid by New England ratepayers beyond the impacts on natural gas prices paid by generators. Failure to add such infrastructure similarly has the potential to increase electric costs paid by New England ratepayers.

The crucial assumption to enable impacts is that the energy delivered via the transmission lines features low (or no) variable costs, such as in the case of wind or hydro, and thus is able to be bid in prices at lower levels than current marginal units (notably powered by natural gas, as discussed above). Prior studies[24] of the impacts of the Northern Pass project were relied upon to approximate the impacts of the 500 MW addition on prices shown in Table 4. No results were calculated in 2016 and 2017 since the transmission line was realistically assumed to not be in service until June of 2018.

TABLE 4: REDUCTION IN LMPS DUE TO ADDITION OF 500 MW TRANSMISSION FACILITY ($/MWH)

| Season | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Annual | -- | -- | $0.43 | $0.41 | $0.41 |

Summing the two LMP impacts shown in Table 3 and Table 4 yields the total $/MWh cost increase if pipeline and transmission infrastructure assumed in the unconstrained infrastructure investment case is not built.

[22] LMPs represent a region-wide average rather than for a specific location.

[23] During the winter months when the price of natural gas becomes high enough, some generators switch over to oil.

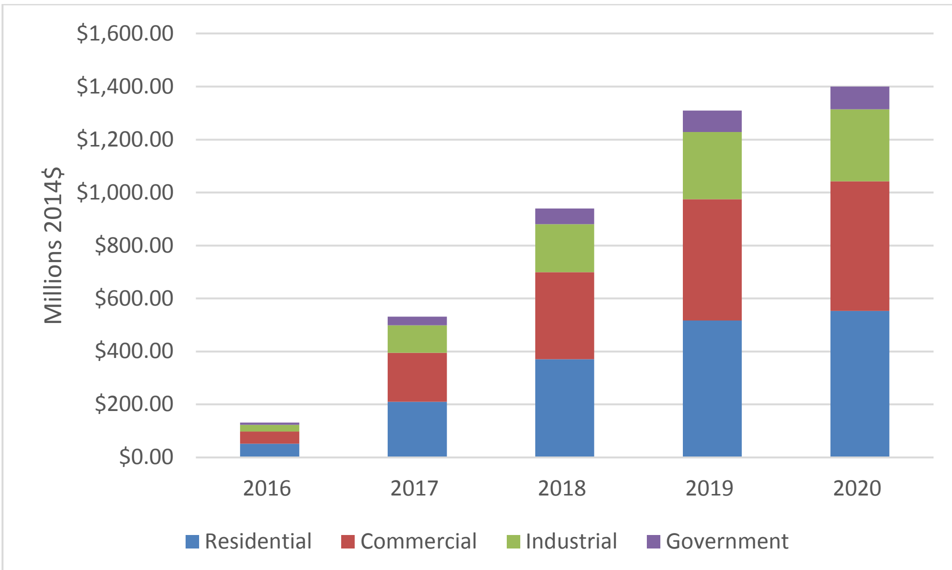
[24] "LMP and Congestion Impacts of Northern Pass Transmission Project – Final Report", Charles River Associates, December 2010 and "Electricity Market Impacts of the Northern Pass Transmission Project", PA Consulting Group, June 2012.

TABLE 5: COMBINED INCREASE IN LMPS, CONSTRAINED CASE ($/MWH)

| Season | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Annual | $1.05 | $4.31 | $7.98 | $11.08 | $12.15 |

Figure 3 shows the cost impacts on electric energy costs. These estimates were obtained by applying the LMP changes shown in Table 5 with forecasted electricity demand**.**

FIGURE 3. INCREASE IN ELECTRIC ENERGY COSTS, CONSTRAINED CASE




In total, failure to expand pipeline infrastructure and transmission will lead to approximately $4.3 billion (in 2014$) in higher electricity costs for the region. The great majority of this total (almost $4.2 billion) is due to decreases in natural gas costs that are on the margin for a majority of the time.

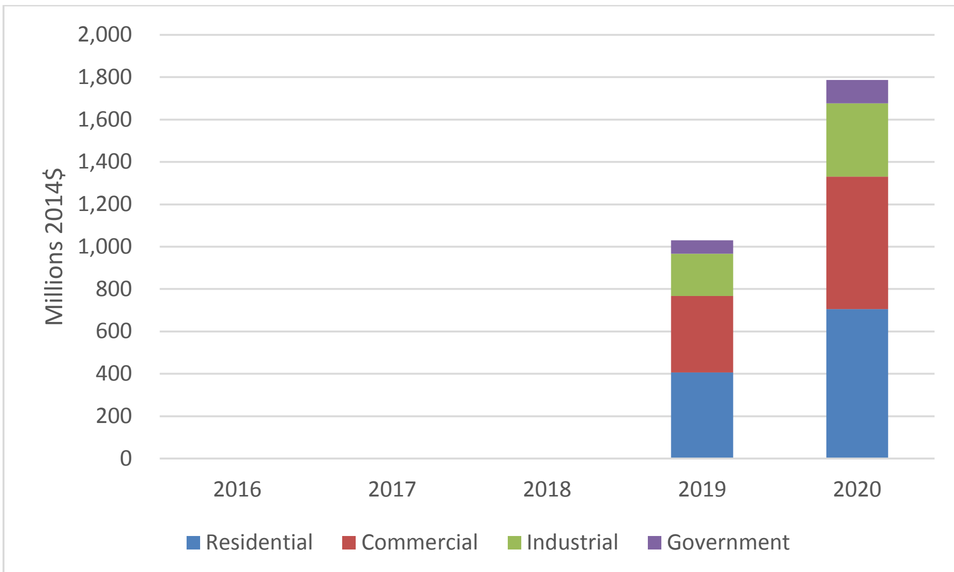
## 2.4 ELECTRIC CAPACITY MARKET IMPACTS

The Forward Capacity Market (FCM) is a wholesale capacity[25] market administered by the regional operator ISO New England (ISO-NE). The primary goal of the capacity market in New England is to procure enough capacity for a specific commitment period, which spans from June 1st to May 31st of the following year, to meet the installed capacity requirement ("ICR") calculated by ISO-NE. Revenues are paid to resources that can provide capacity, and these revenue streams are distinct from the electric energy revenues (or costs) discussed above.

[25] Capacity represents the amount a resource can provide during specific conditions at an instant point in time. Energy, by contrast, is the amount of production over a time period (hour, month, etc.).

For modeling purposes, the capacity impact analysis excluded two new generating units (one being 725 MW and the other 195 MW) that are under development and that cleared in the most recent annual auction (for the June 2018 to May 2019) from the supply curve. No impacts from the period prior to June 2019 were included, since resource commitments have been largely assigned, and it is likely that any lost capacity would be replaced by other market participants. Since the capacity commitment periods span over two calendar years, the impact of the 920 MW on a calendar year basis was calculated to provide a more consistent picture when comparing with the other components of the overall energy price impacts. The estimates are shown below.

FIGURE 4. INCREASE IN ELECTRIC CAPACITY COSTS, CONSTRAINED CASE




The capacity market impact for calendar year 2019 is forecasted to be close to $1 billion in 2019 and close to $1.8 billion in 2020, for a total of about $2.8 billion over the two-year period. These are additional cost impacts to the energy impacts discussed above that would be reflected in customers' bills during the years specified in the figure.[26]

## 2.5 RPS MARKET IMPACTS

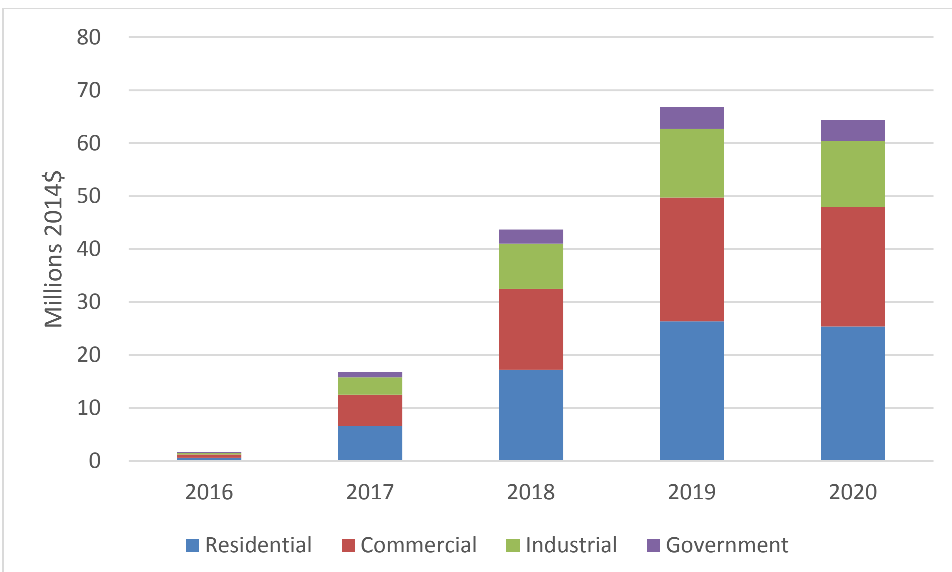
As introduced earlier, RPS place certain purchase requirements on load serving entities ("LSEs"), such as electric utilities and competitive retail suppliers. Requirements are stated as a minimum percentage of total electricity supply per year and can be met with energy produced by RPS-qualified generators in the form of renewable energy certificates.

[26] Retail electricity bills include a number of components that pay for distribution, transmission, and supply services. Distribution and transmission services were not analyzed in this study. Supply services include energy, capacity, other wholesale costs and retail cost components (including RPS costs that are discussed in the next section).

Alternative compliance payments ("ACP") provide a way for load serving entities to meet their requirement levels without the purchase of renewable energy certificates ("RECs") and were instituted to provide a cap on the cost exposure of LSEs during shortage conditions. Use of ACP increases as renewable supply conditions approach or are at shortage conditions (supply less than demand). ACPs are generally set at a rate that increases with inflation. Thus, if gaps remain between supply and demand, LSEs (and eventually ratepayers) will be forced to meet their RPS requirements at ACP levels. For example, if wind resources are not built to meet the requirement, then ratepayers will pay additional costs. On the other hand, if wind resources are built to meet the RPS needs, then ratepayers should pay somewhat less than ACP, given the relatively high value set for the ACP (to discourage use of the ACP over purchasing renewable energy).

This difference was calculated using a forecast of REC prices. In order to calculate ratepayer impacts of continuing with the above supply-demand conditions, the difference between these two prices was multiplied by the amounts necessary to meet the demand levels specified in states' RPS. Results of this calculation are shown in Figure 5, as allocated to the customer segments.

FIGURE 5. INCREASE IN RENEWABLE PORTFOLIO STANDARD COSTS, CONSTRAINED CASE




The cost impact of failing to build renewable generation infrastructure is close to $200 million over the 2016-2020 period. Future years' impacts would be expected to be at least the amount shown in 2020 given the increase in RPS requirements.

# 2.6 NET COST IMPACTS

In rolling up all of the components cited above, it is necessary to consider several off-setting costs which would not be paid in the constrained infrastructure case. Where infrastructure is funded by private sector market participants, such as generating companies that use debt and equity financing to fund investment, these participants have made the financial decision to invest and borrow with the expectation that revenue streams (from a variety of sources) will support the investment. These revenue streams may include ratepayer funds in addition to market revenues that would otherwise go to other market participants.

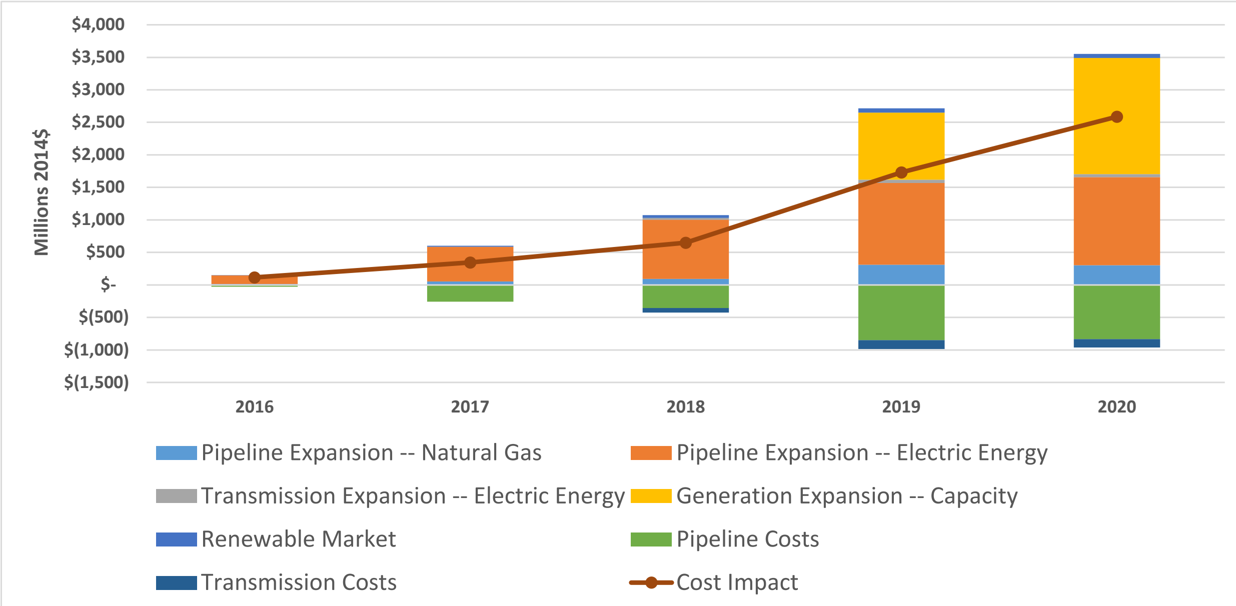
The pipeline expansion assumed above will involve new costs to customers that will not be displaced or transferred from existing market participants. Pipelines are not constructed without long-term contracts, historically from natural gas LDCs. For the purposes of this study, it was assumed that the entire pipeline buildout will be paid through surcharges on customers' bills without distinguishing (for simplicity) between electric and natural gas customers.

In addition, the cost of the transmission expansion was also included because it is anticipated that a ratepayer-backed contract will be necessary to support financing of the transmission investment. The contract is likely to include both the cost of the transmission and the cost of power, but it was assumed that the cost of the power portion of the contract would be offset by market revenues.

Finally, no additional costs for the generation buildout (renewable and non-renewable) were included. These facilities may or may not feature long-term contracts, but it was assumed that the ratepayer monies would be similar in both constrained and unconstrained cases. In the case of the non-renewable facilities, those costs would have been paid to other resources; addition of new generators causes a displacement of these revenues (and an overall reduction in total revenues) among resources. Similarly, ACPs would have been paid in the constrained case, and these monies (along with other market revenues) will be paid to resources but do not represent additional ratepayer costs.

Figure 6 shows all components of the impacts discussed above. Positive elements indicate cost impacts due to lack of investing in infrastructure. Negative elements indicate "savings" to customers from not spending funds on infrastructure. The line represents the "net cost" to New England customers of failing to invest in the infrastructure elements studied.

FIGURE 6. COST IMPACTS OF CONSTRAINED ENERGY INFRASTRUCTURE IN NEW ENGLAND[27]




In total, about $5.4 billion in additional net energy costs are expected to be incurred if infrastructure is not expanded by the levels found in the unconstrained case. This is a net cost number and includes increased costs paid to pipeline and transmission owners. The largest cost impact is on electricity energy costs due to pipeline expansion followed by electric capacity costs. It is important to note that the electricity energy costs due to pipeline expansion exceed the amounts that would be used to pay for the pipelines over the entire study period. The remaining cost impacts—natural gas costs, renewable market costs, and energy cost impacts from the transmission expansion—are minor in comparison to those two categories.

## 2.7 INFRASTRUCTURE SPENDING DOLLARS

In addition to the energy cost savings impacts, there will be construction-related impacts from the infrastructure development. It is important to note that these construction spending numbers are distinct from the cost impact estimates developed above. The cost impacts discussed in the prior section are the amounts paid by customers. By contrast, the estimates shown in this section are paid by project developers to construct the various infrastructure types. The construction impacts shown here are limited

[27]$5.4 billion of increased energy costs will be incurred by the region's consumers if infrastructure is not expanded by the levels modeled in the unconstrained case. This takes into account the costs consumers save by not building infrastructure – including $2.3 billion in pipeline costs and $330 in transmission costs over the study period.

to the years 2016-2019, while cost impacts would occur after the study period and throughout the lifetime of the infrastructure investments.

Various assumptions about infrastructure investment were used to calculate the construction spending underlying the infrastructure expansion in the unconstrained case (see Table below).

TABLE 6. INFRASTRUCTURE INVESTMENT ASSUMPTIONS

| Infrastructure | Construction Timeline Assumptions | Cost Assumptions (2014$) |
|---|---|---|
| Natural Gas Pipeline | 18 months | $2.84 million/MMcf[28] |
| Natural Gas Generation | 36 months (combined cycle);<br>18 months (combustion turbine) | $1070/kW[29] (combined cycle)<br>$820/kW (combustion turbine) |
| Transmission | 24 months | $1.2 million/MW HVDC[30] |
| Wind Generation | 12 months | $2200/kW[31] |

The goal of this analysis was not to present a detailed analysis of the construction impacts, but to provide an order-of-magnitude estimate for the direct impact of infrastructure investment for input to the REMI model. Infrastructure costs are highly dependent on project-specific considerations and the cost assumptions were developed by examining publicly available studies for similar projects or infrastructure facilities. The construction timelines were used to allocate investment dollars over the study period. Only investments that occur in the 2016-2019 period were included. Thus, for the pipeline buildout that was assumed to be in place in November 2016, only a portion of the construction impacts were included since most of the construction time occurred prior to 2016.

Figure 7 shows the allocation of construction expenditures across the study period and for the different infrastructure elements.

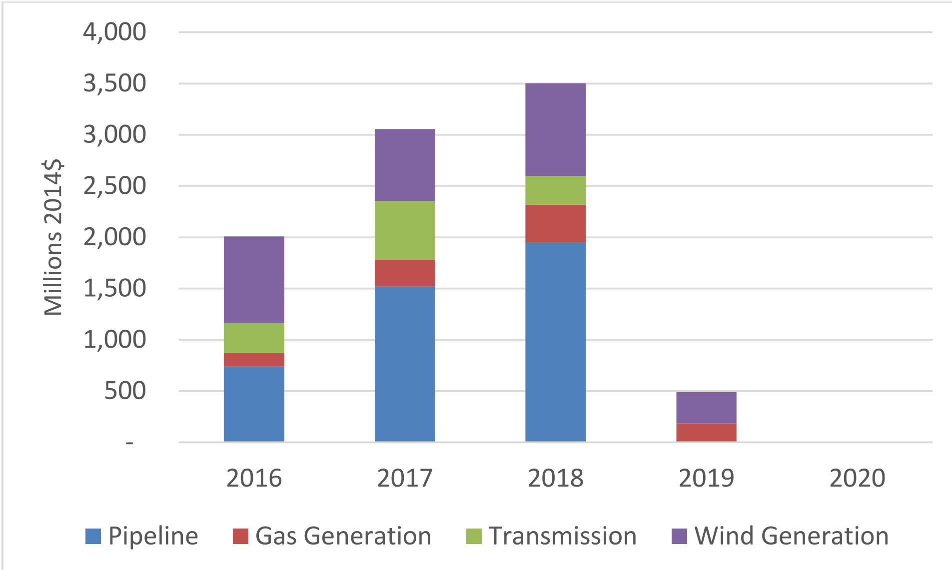
28 Estimated from information found in FERC ORDER ISSUING CERTIFICATE AND APPROVING ABANDONMENT, Docket CP14-96-000, March 3, 2015.

29 Estimated from information found in "Net CONE for the ISO-NE Demand Curve," Presented to NEPOOL Markets Committee, Brattle Group, February 27, 2014.

30 Estimate by La Capra Associates, Inc.

31 Ibid.

FIGURE 7. INFRASTRUCTURE INVESTMENT, UNCONSTRAINED CASE




Under the unconstrained scenario, approximately $9.0 billion of infrastructure investment would be made between 2016 and 2019. No construction impacts are shown for the last year in the study period because all facilities are assumed to be in place by the start of 2020. These figures represent direct expenditures to construct the facilities. Operations and maintenance ("O&M") expenses were not included because it was assumed that some amount of these expenses would be offset by reduced O&M expenses due to displacement of existing facilities, and these O&M expenses would be relatively minor over the 5-year study period compared to the construction expenditures.

# 3. ECONOMIC IMPACTS

The economic consequences of constraints on infrastructure investment were quantified by using a dynamic, impact forecasting tool developed by Regional Economic Models, Inc. (REMI). This model was selected because of its ability to examine price effects by customer segment and changes in competitiveness of commercial and industrial sectors in the region relative to other parts of the United States. Appendix D contains an overview of the model.

Macroeconomic impacts – annual effects as well as effects over time which result in lower consumer spending, reduced business competitiveness, and lower government spending (to achieve a balance budget requirement) – are stated in terms of jobs lost, and lost dollars of gross regional product (GRP – a measure of the region's income generating ability). A key component of a region's income generation is personal income largely driven by earned income impacts. Sector-specific impacts were also identified across service industries, manufacturing, construction, retail and wholesale trade.

## 3.1 CASES MODELED

Two cases were assessed with the REMI model based on insufficient energy infrastructure investment over the 2016 to 2020 time frame: 1) the macroeconomic effects of unrealized construction activity (estimated at $9 billion); and 2) the ensuing higher energy costs (estimated at $5.4 billion).

Construction-related scenarios are typically characterized as short-term events leading to temporary impacts (sometimes referred to 'boom-bust' in the context of building a project). In comparison, an investigation of a run-up (or down) of prices is often thought of as a more persistent type of event, and therefore an analyst would typically not combine impacts from these two situations as it obscures the different degrees of permanence. However, these different degrees of permanence are not considered significant in this study because of the short time frame under consideration and the coincidence of the analysis interval. Therefore the conclusions cited for key results are a combination of these two cases.

For definitional purposes, a "job lost" encompasses: i) the loss of an existing job, or (ii) it may reflect a "slower addition" or growth of new positions over the period of 2016 through 2020. Finally, the job impacts discussed in this report are a combination of full and part-time positions.

## 3.2 IMPACTS RELATED TO FOREGONE CONSTRUCTION ACTIVITY

Figure 7 in Section 2 contains the data that was used as inputs for the REMI case of foregone construction activity. Table 7 below shows the key economic aspects of the various under-invested infrastructure (delayed, not built, or not fully built). A portion of each type of infrastructure with a labor requirement was assumed to have been from resident workforce within New England. The balance of the infrastructure budget – spent on materials/equipment/supplies ("MES") – is viewed as demand that arises in New England but will not necessarily be entirely fulfilled by New England businesses. The MES dollars that aren't fulfilled by a business within the region are the leakage of project budget to outside economies.

TABLE 7. SCHEDULE OF FOREGONE CONSTRUCTION OF ENERGY INFRASTRUCTURE (MILLION 2014$)

| **Infrastructure Type** | Local Labor requirement[32] | Materials/ Equipment/ Supplies, demand | **2016** | **2017** | **2018** | **2019** | **Total** |
|---|---|---|---|---|---|---|---|
| Pipeline | 40% | 60% | -$742 | -$1,521 | -$1,951 | $0 | **-$4,214** |
| NGas CC plants | 36% | 64% | -$129 | -$259 | -$365 | -$183 | **-$936** |
| Transmission lines | 36% | 64% | -$292 | -$573 | -$281 | $0 | **-$1,146** |
| On-shore Wind | 2% | 98% | -$844 | -$702 | -$905 | -$307 | **-$2,758** |
| ***All Types*** | | | **-$2,007** | **-$3,055** | **-$3,502** | **-$489** | **-$9,054** |

The foregone labor compensation related to this schedule represents 29 percent of the $9 billion of estimated infrastructure investment. Cross-referencing the non-labor budget requirements of prior onshore Wind projects (NREL JEDI) as well as comparable NAICS sector information[33] for power plants and transmission line projects (sector 23713) and pipeline projects (sector 23712), the local capture is approximately 24 percent across the entire bundle of projects.

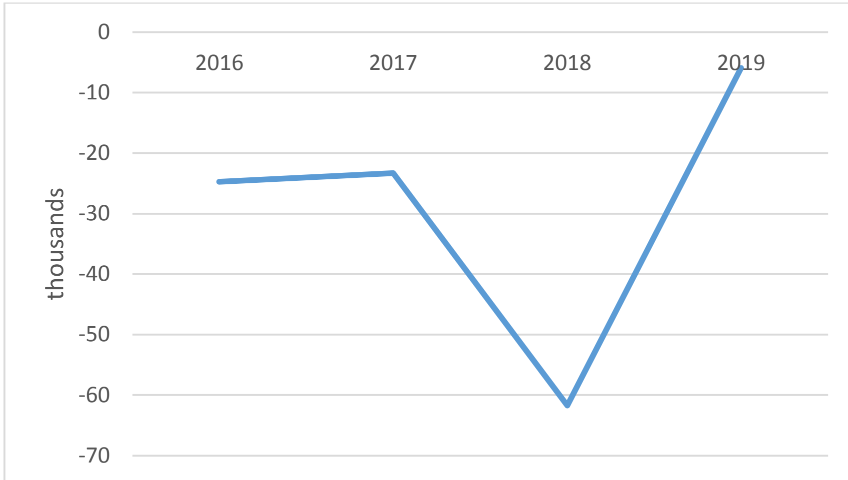
The total local content (either in the form of a paycheck or a procurement contract) would have been nearly 53 percent of the $9 billion investment estimate. This is the local shock that is removed from the New England economy as a combination of unrealized construction sector compensation, and contracts to a variety of local based sectors (in the amounts that do not leak away) known to provide MES into any of these project types. Thus, if infrastrucdture projects do not go forward, the region does not realize 53 percent of the investment dollars spent by project sponsors.

For New England, the job consequences of under investing in energy infrastructure projects leads to an average rate of job loss of 28,900 per year in the private-sector between 2016 and 2019 (or a total of 115,600 temporary or permanent jobs over that timeframe). Figure 8 shows the timing of the employment impacts that largely mirror the schedule of foregone construction from Table 7.

32 The labor expenditure to complete any of these infrastructure projects is determined by industry-specific data contained in relevant NREL JEDI or regional IMPLAN detailed sector files.

33 An IMPLAN model of the Massachusetts economy (based on 2013 calibration) was cross-referenced for the industry-spending patterns which describe the disposition of the non-labor requirements for the annual production of any sector. Here two IMPLAN sectors were examined which contain the construction of all but the wind infrastructure.

FIGURE 8. PRIVATE-SECTOR JOBS LOST IN NEW ENGLAND FROM LOWER INVESTMENT ACTVITY




The sectors most affected by lost jobs from lack of energy infrastructure investment are shown in Figure 9, based on the average annual jobs impact. It is not surprising that the largest share of jobs affected are in the construction sector. Other sectors are implicated through (i) involvement in the supply-chain of these infrastructure projects, or (ii) by the economic multiplier effects that are catalyzed when economic activity changes (up or down) and household earnings are affected.

The decrease of regional income, expressed through dollars of gross regional product (GRP), is $10.5 billion between 2016 and 2019 (Figure 10). Importantly $8.5 billion of this decrease is personal income affecting consumers throughout the region. The timing of this impact has a pattern similar to the amount of unrealized jobs over time.

FIGURE 9. PRIVATE-SECTOR JOBS LOST BY SECTOR FROM LOWER INVESTMENT ACTIVITY

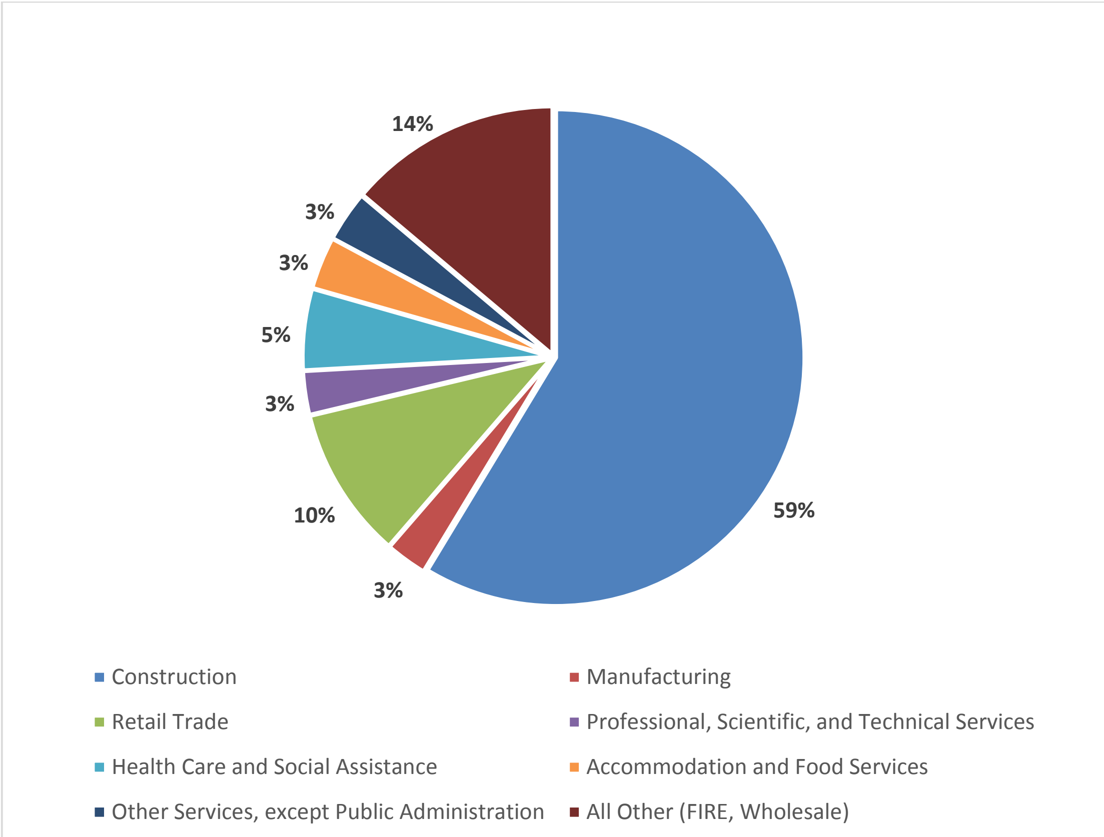
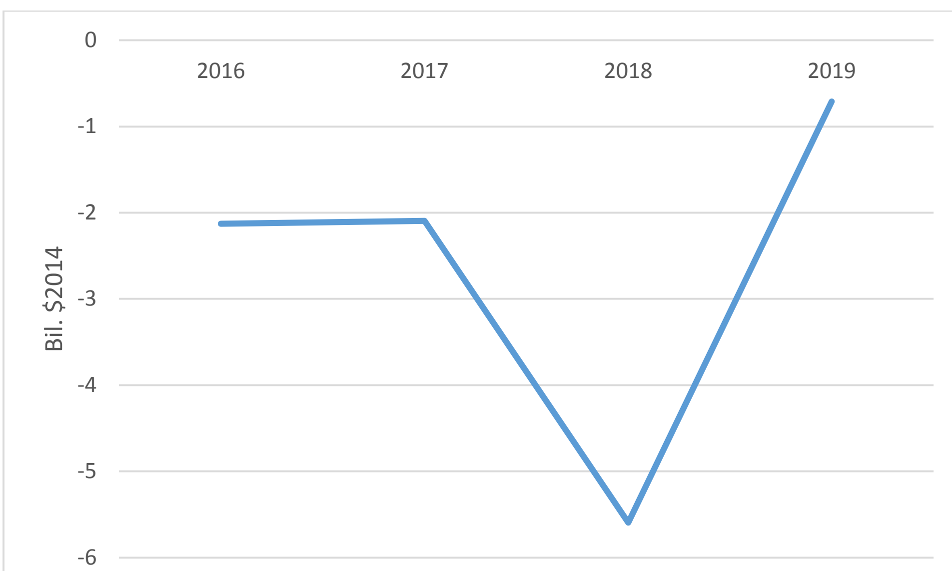



FIGURE 10. GROSS REGIONAL PRODUCT LOSS IN NEW ENGLAND, CONSTRAINED CASE



# 3.3 IMPACTS RELATED TO HIGHER ENERGY COSTS

Section 2 calculated the higher energy costs that would be incurred under the constrained infrastructure investment case which were inputted into the REMI Model (Figure 6).

Table 8 below portrays the time-path of the cost escalation and the relative allocation across broad customer segments**.**

TABLE 8. ANNUAL ENERGY COST CONSEQUENCES OF CONSTRAINED INFRASTRUCTURE

| | | **2016** | **2017** | **2018** | **2019** | **2020** | |
|---|---|---|---|---|---|---|---|
| | **2014$m** | $ 117.13 | $ 343.59 | $ 649.75 | $ 1,730.90 | $ 2,589.37 | **$5,430.74** |
| ***Share of Burden*** | Residential | 36% | 34% | 35% | 39% | 39% | |
| | Commercial | 37% | 39% | 38% | 35% | 35% | |
| | Industrial | 20% | 20% | 20% | 19% | 19% | |
| | Public sector | 7% | 7% | 7% | 6% | 6% | |

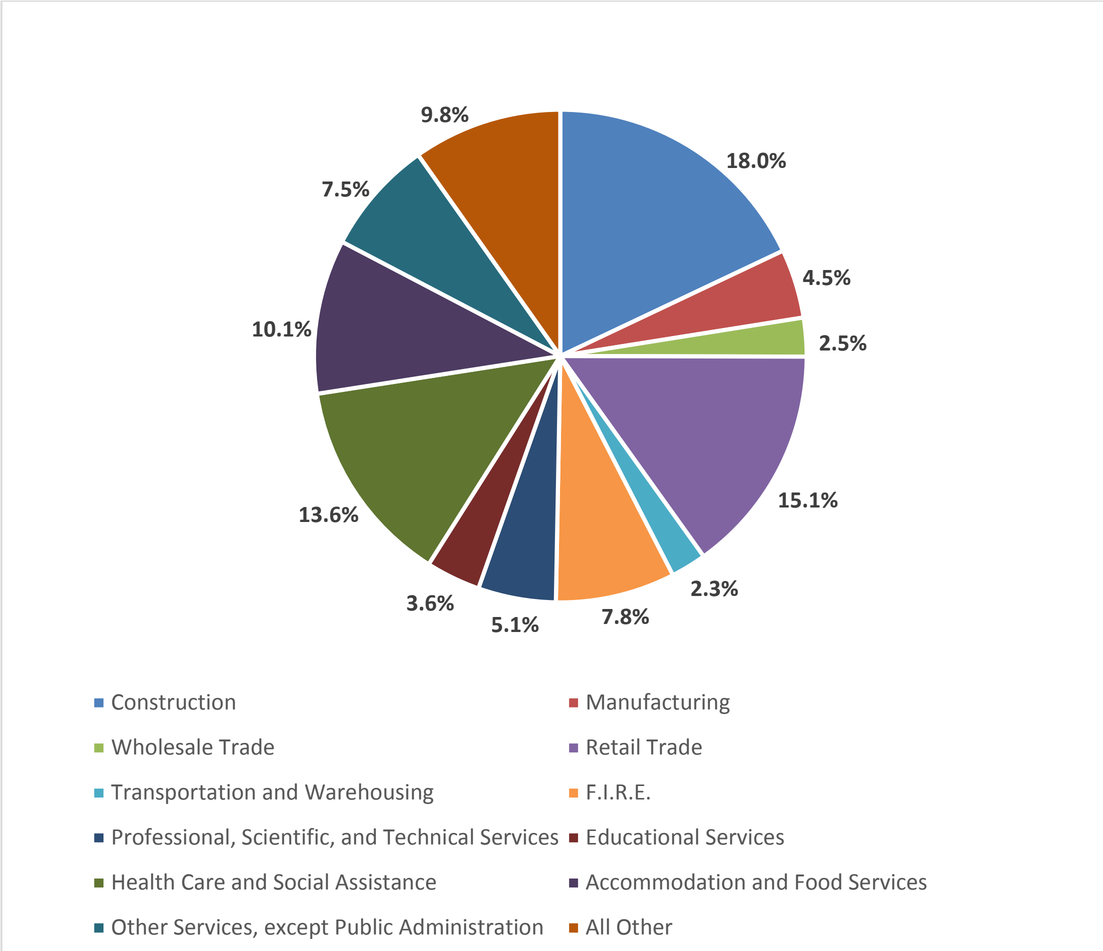
The residential segment will experience a decrease in purchasing power; the public sector (comprised of state and local government functions) will need to off-set the higher cost with reduced public program spending or higher taxes/fees in order to balance their budgets; and the commercial and the industrial segments overall energy cost increase is allocated to the underlying aggregated REMI sector definitions assigned to those categories (27 commercial activities and 36 industrial activities operating in the New England economy) using each sector's fuel use[34] per dollar of sales and the sales for each sector.

Between 2016 and 2020, the region will temporarily or permanently lose 52,000 private-sector jobs[35] due to higher energy costs. In 2020 alone, when the energy cost escalation is largest, the New England economy will forfeit 25,600 private-sector jobs. This negates 80 percent of the private-sector job growth projected by the REMI model for the region in 2020. For perspective, Figure 11 shows which sectors shed the most jobs in 2020 which is a reflection of (i) the relative energy cost burden carried as a commercial or industrial energy customer, (ii) how that burden affects the market share of the sector, and (iii) multiplier effects instigated by changes on other energy customers (within the same segment or not).

34 Excluding residual fuel oils.

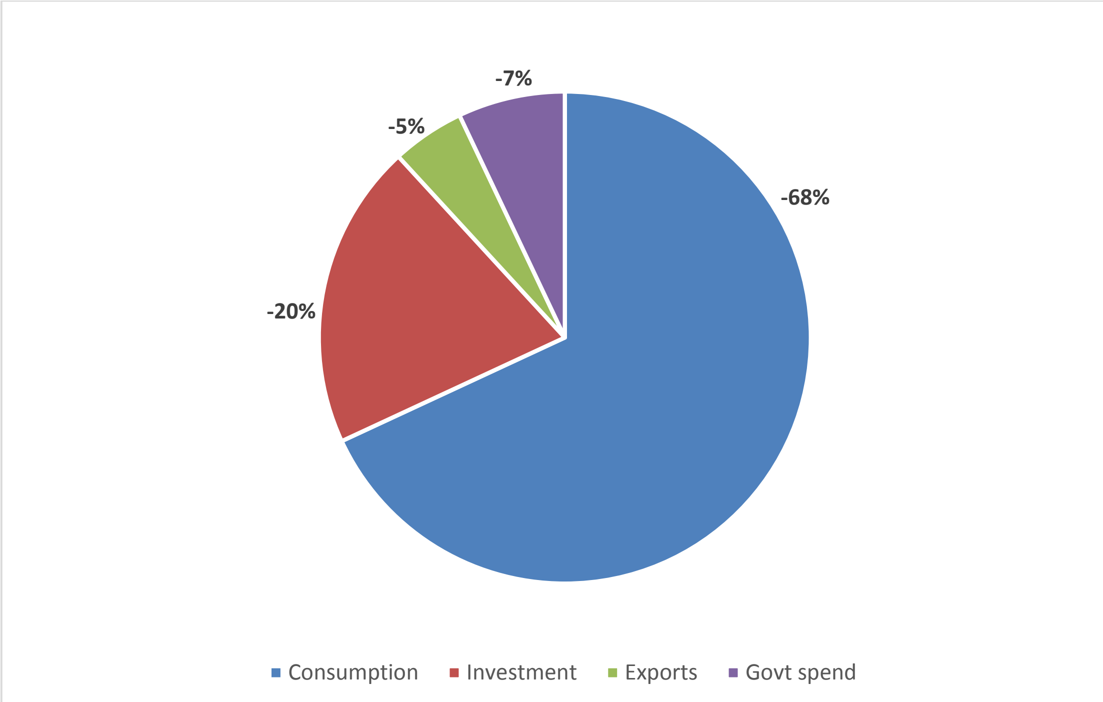
35 Job years.

FIGURE 11. NEW ENGLAND PRIVATE SECTOR JOBS LOST IN 2020, BY SECTOR, FROM HIGHER ENERGY COSTS




Between 2016 and 2020, the New England economy will lose almost $5.6 billion of gross regional product (GRP) from higher energy costs, $4.0 billion of which would be decreased personal income. Figure 12 shows that the most significant reason for this decrease is due to reduced purchasing power by households (which it should be noted, also curtails imports of consumer goods). The residential customer segment shoulders the largest portion of the higher energy costs. This is followed by a contraction in general investment, reduced state and local government spending, and reduced export business from a loss of competitiveness.

FIGURE 12. NEW ENGLAND'S LOST GROSS REGIONAL PRODUCT FROM HIGHER ENERGY COSTS, BY SOURCE




## 3.4 COMBINED IMPACTS FROM FOREGONE CONSTRUCTION ACTIVITY AND HIGHER ENERGY COSTS

As discussed at the beginning of this section, because the timeframe for the study is so short, the economic impacts from foregone construction activity and higher energy costs can be reasonably combined. Doing so allows for a comprehensive perspective on the impacts from failing to build energy infrastructure in New England. Therefore, the consequences of not investing in the energy infrastructure modeled in this study between 2016 and 2020 will lead to job losses of 167,600 and a reduction in disposable income of $12.5 billion.

# APPENDIX A – INFRASTRUCTURE OVERVIEW

The focus of this study is on the physical infrastructure (facilities and systems) used to deliver natural gas and produce and deliver electricity to the New England region. "Soft" infrastructure in the form of market structures, regulators (state and federal), and rules, regulations, and policies, is also critical. Both types of infrastructure are used by market participants (buyers and sellers) to enable transactions, which are conducted at some price that will vary based on demand and supply conditions (where markets are active). The regional composition and quantities of infrastructure located in different regions of the U.S. relative to the demands of those regions can have large impacts on energy prices paid in different regions and can cause large disparity in regional energy prices and costs paid by households and businesses.

The New England states generally do not feature indigenous production of primary fuels, such as distillate and natural gas, which are used to power generators and for home heating and commercial/industrial process loads. Delivery infrastructure provides a crucial link with producing regions to supply the energy demands of the region that are not being met through use of indigenous renewable resources (or more efficient energy usage) or that can be met more cheaply with in-region resources. Hence, imports of energy are an important incremental resource that can both supplement local resources and also provide some competitive pressure on in-region resources. Where there are delivery constraints and/or higher demands internally or from other regions, New England customers will pay higher prices for this imported energy. How these prices will be translated to costs depends on a number of factors, including specific market conditions and use of any hedging strategies or policies.

In addition to delivery infrastructure, the region also relies on production infrastructure in the form of electricity generators. These generators can use fossil fuels, mainly natural gas but also distillate or coal, or renewable resources, such as wind, hydropower, and biomass. As discussed below, electric generators can provide energy and other market products that are necessary to provide delivered electricity to retail customers.

The use of markets, and the interaction between supply and demand play an important part in how resources get allocated in New England. That is, as market prices rise, they should provide a signal for infrastructure developers to take advantage of high prices (from their perspective), enter the market, and thereby reduce prices to "equilibrium" levels. As infrastructure enters the market, one would expect supply pressures to ease and prices to decline[36]. The focus of this study is an examination of infrastructure that serves currently constrained markets, as shown by recent high prices, especially as experienced by electric ratepayers.

There is significant interest in expanding infrastructure to address the market prices discussed in the report. Herein, potential natural gas pipeline and electric transmission projects relative to existing deliverability are described. These infrastructure projects can potentially reduce electricity prices by either increasing the deliverability of natural gas during constrained times or reducing the demand for natural gas by importing energy from non-gas-powered sources located outside or using resources inside of New England. Thus, with respect to electric market impacts, these projects serve as substitutes.

[36] Demands may increase due to lower prices, but we did not examine (or assume) any changes in demand as a result of potentially lower prices. An assumption of inelastic demand has very minor impacts on the analysis in this report.

Additional generation (renewable and non-renewable) can also impact energy markets, but these infrastructure types were directed towards other cost elements and are discussed below.

## NATURAL GAS PIPELINES

Natural gas pipeline deliverability into the region has largely remained unchanged over the past 5 years (and beyond). The table below shows one estimate of the in-bound contracted capacity currently available to the New England region.

TABLE A-9. PIPELINE DELIVERABILITY IN NEW ENGLAND[37]

| | **MMcf/Day** |
|---|---|
| Algonquin Gas Transmission (AGT) | 1,118 |
| Iroquois Gas Transmission (IGT) | 228 |
| Tennessee Gas Pipeline (TGP) | 1,291 |
| Portland Natural Gas Transmission (PNGTS) | 249 |
| Maritimes and Northeast Pipeline (M&N) | 833 |
| **Total In-Bound Contracted Capacity** | 3,719 |

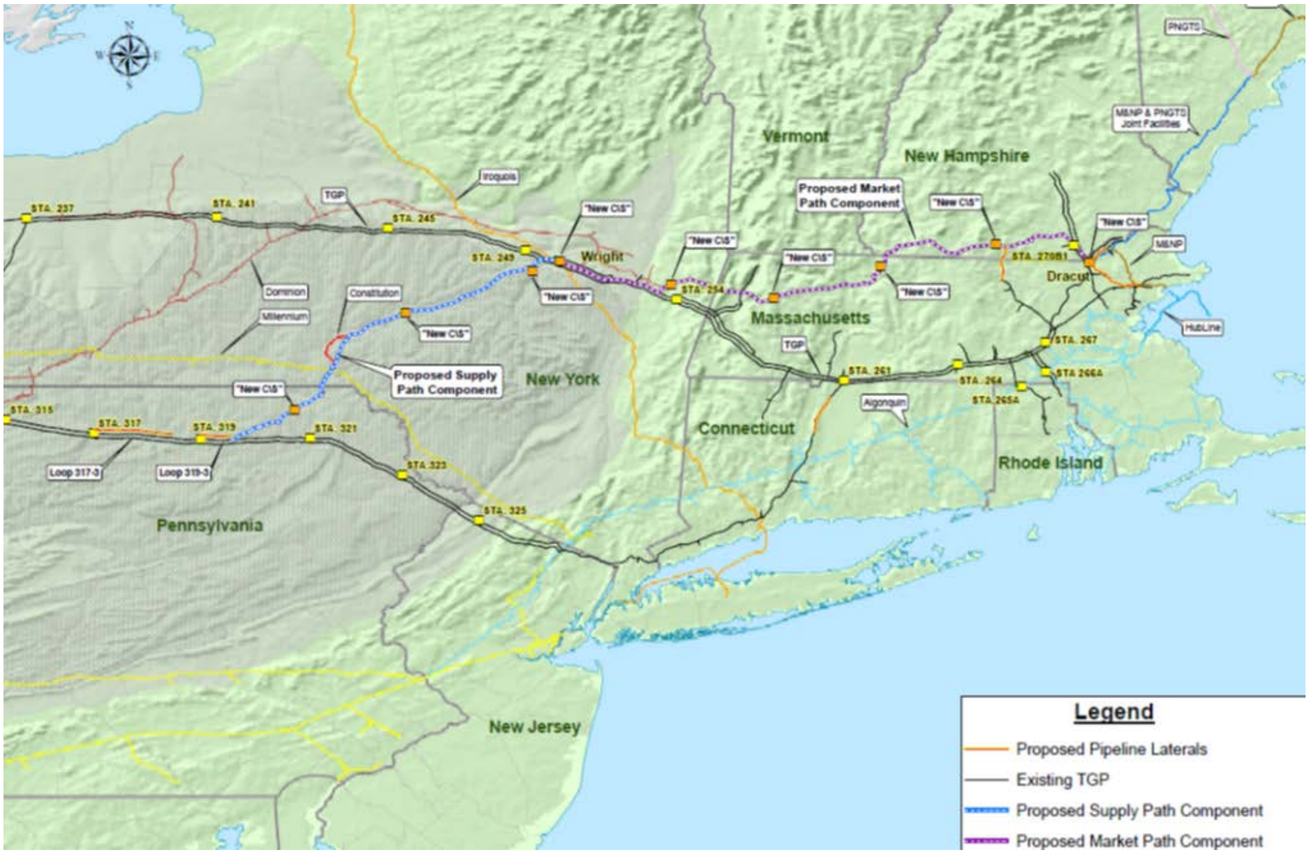
A number of proposed pipeline projects would significantly add to the capacity numbers shown in the table.[38]

- Tennessee Gas Pipeline Northeast Energy Direct ("NED"): Kinder Morgan's Northeast Energy Direct project is a two-part project, the Market path and Supply Path. The market path of NED will enable up to 1.2 Bcf/Day of transportation capacity from the receipt point at the Wright Interconnection to the delivery point at Dracut, Massachusetts with a majority of the project being co-located along the existing Tennessee Gas Pipeline. The supply path of the NED project will enable up to 1.2 Bcf/day transportation capacity to the Wright Interconnection in New York where it would connect to the market path. The Northeast Energy Direct project market path is expected to be in-service by November 2018.

[37] "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II", November 2014. ICF International.

[38] Brief discussions of the projects, as described by the project sponsors, are provided. The size of the buildout in the descriptions below differ from the buildout examined in this study.

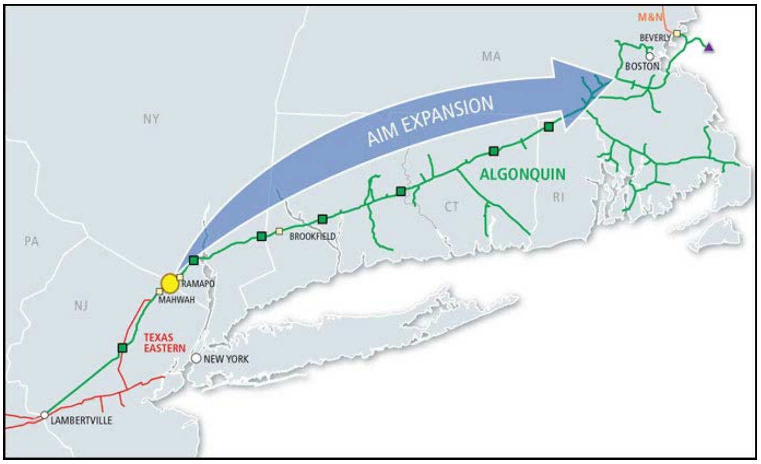
FIGURE A-13. NORTHEAST DIRECT PROJECT




Source: Kinder Morgan

- Algonquin Incremental Market Expansion (“AIM”): Spectra Energy’s Algonquin Incremental Market Expansion Project expands on the existing capacity of the Algonquin pipeline to add 0.342 Bcf/day of capacity. The project starts at the Algonquin pipeline in Mawhawa, New Jersey and extends to Beverly, Massachusetts. AIM is currently under construction and expected to be in-service by November 2016.

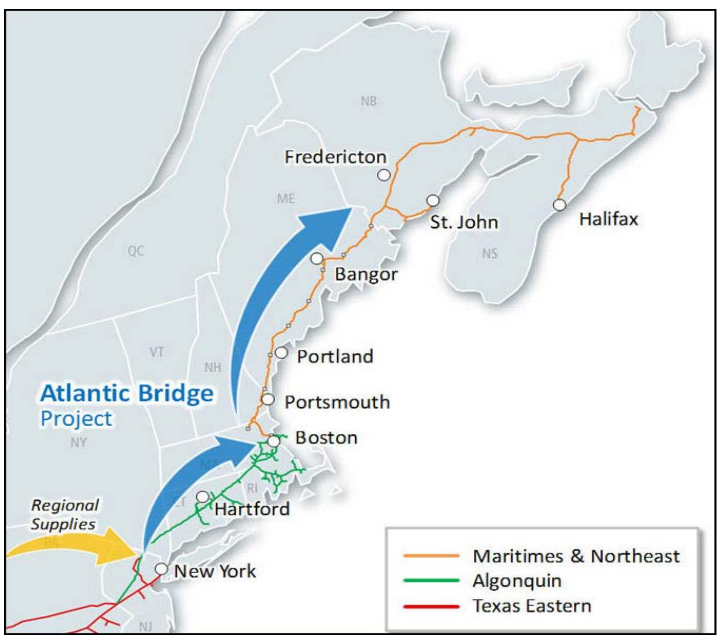
FIGURE A-14. AIM EXPANSION PROJECT




Source: Spectra

- Atlantic Bridge: Spectra's Atlantic Bridge Project upgrades the existing Algonquin and Maritimes & Northeast Pipeline to provide up to an additional 0.222 Bcf/d of transportation capacity. Atlantic Bridge's planned in-service date is November of 2017.

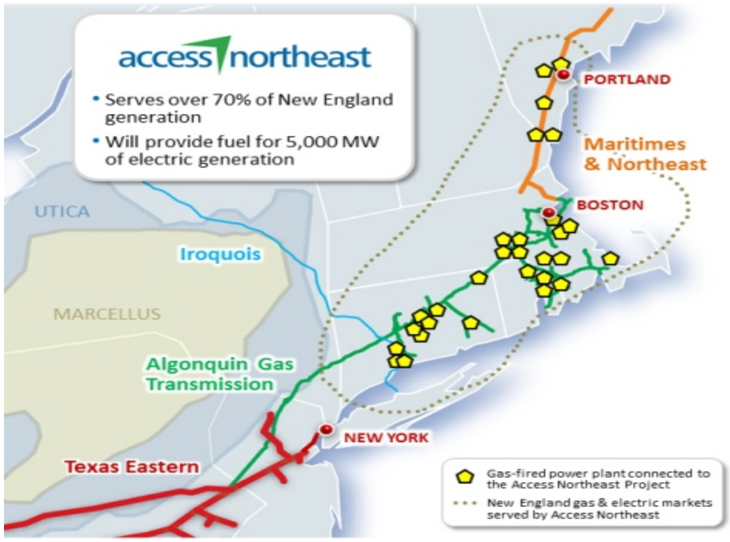
FIGURE A-15. ATLANTIC BRIDGE PROJECT




Source: Spectra

- Access Northeast: The Access Northeast project is a partnership between Spectra, Eversource Energy, and National Grid. Access Northeast differs from other projects proposed as its primary focus is providing firm natural gas transportation capacity for electric reliability and its anchor shippers are the electric distribution companies. The project will expand the existing transportation capacity on the Algonquin pipeline system by up to 1 Bcf per day. The project is expected to be in service November 2017.

FIGURE A-16. ACCESS NORTHEAST PROJECT




## *ELECTRIC TRANSMISSION*

In New England, there are six major proposals (among a larger group) to add substantial new capacity to the Grid for the sake of bringing more clean energy into the region.

1. The Northern Pass: a 1200MW mostly overhead high voltage direct current ("HVDC") project that will enable imports of power from the province of Quebec to Franklin, NH, from where additional Grid upgrades would bring most of the power into the "Mass Hub," the heart of the southern New England market. Northeast Utilities and NStar are the sponsors, working with Hydro Quebec as a supplier.
2. The New England Clean Power Link: a 1000MW HVDC project that will also enable imports of power from the province of Quebec, down the length of Vermont using Lake Champlain as a conduit for a buried cable, to one of three possible connection points in southern Vermont, from where the power flows into the "Mass Hub." Transmission Developers International ("TDI") is the sponsor.
3. The Green Line 1200: a 1200MW hybrid land-and-sea HVDC project that will enable up to 1200MW of wind in Northern Maine, "firmed up" by imports of power from the provinces of New Brunswick, Quebec, or Newfoundland (via) Nova Scotia. It is expected to be buried under the ocean floor from Searsport, Maine to a landfall near Lynn, Massachusetts, from which a buried cable would inject the power into the Wakefield, Massachusetts substation, in the heart of the Northeast Massachusetts ("NEMA") market and into the "Mass Hub."
4. The Grand Isle Intertie: a 400MW buried high voltage alternating current ("HVAC") project that can enable up to 400MW of wind in New York, "firmed up" by imports of power from

New York, transiting a short distance from west to east under the bottom of Lake Champlain, from Plattsburg, New York to Burlington, Vermont.

5. The Northeast Energy Link ("NEL"): a 1200MW HVDC project from the Orrington (near Bangor), Maine area to Tewksbury, Massachusetts. The NEL proposes to bury the transmission cable alongside Interstate 95.
6. Maine Power Express: comprised of a northern, underground section and a southern, underwater section. The Northern Section will be located within the existing 200 mile long, 50 foot wide Searsport - Loring easement corridor ("S-L ROW"), formerly used to pipe jet fuel to Loring Air Force Base from Searsport. The Southern Section of the transmission path begins at Mack Point in Searsport, Maine and proceeds underwater to Boston Harbor. The final portion of the southern section passes through the Boston harbor towards its termination point, the south DC converter station located at Massport Conley Terminal, a few hundred feet from the K Street Substation.

The six projects represent transmission to Canadian resources or transmission that harvests both onshore wind and Canadian imports. Similar to the pipeline projects, the projects in total would represent a large expansion of existing import capability (see table below.).

TABLE A-10. MAXIMUM IMPORT TRANSFER CAPABILITY (MW) OF EXISTING REGIONAL INTERTIES

| Highgate (Quebec) | Hydro Quebec | New Brunswick | New York (North) | New York (Northport) | New York (Cross Sound Cable) | Total |
|---|---|---|---|---|---|---|
| 225 | 2,000 | 200 | 1,400 | 200 | 336 | **4,361** |

Source: ISO-NE

## ELECTRIC GENERATION

Appendix C shows expansion of generation forecasted over the near term compared to historical amounts, which reflect retirements and additions. The appendix also discusses the renewable generation for meeting renewable portfolio standards and the calculation of the difference between assumed supply (which includes existing and forecasted buildout) and demand levels over the study period.

# APPENDIX B – NATURAL GAS/LOCATIONAL MARGINAL PRICE MODEL OVERVIEW

## MODEL STRUCTURE

La Capra Associates utilized a Monte-Carlo based model to study the impact of gas pipeline additions on New England gas prices and locational marginal prices ("LMPs"). The core of the model is the relationship between natural gas pipeline headroom (unused capacity) and the natural gas basis differential between the primary New England delivery point (Algonquin Citygate) and TETCO M-3. The model calculates pipeline headroom based on forecasted New England natural gas supply and demand and then uses the historical relationship between pipeline headroom and natural gas basis to predict the price of natural gas delivered to New England. Given the cost of electricity and the percentage of time each resource is on the margin, the model calculates an LMP for each trial.

Key inputs to the model include: natural gas pipeline capacity, LDC natural gas demand, electric demand for gas, additional imports or renewable additions, and resources on the margin in ISO New England. The model simulates four distinct scenarios. First, the model allows selection between summer and winter conditions. Winter is defined as November through March and is labeled based on the year corresponding to the last three months. Summer is defined as April through October. LDC pipeline demand and electric demand for gas are specific to the summer and winter models. There are also two scenarios for future capacity. The "Unconstrained" case assumes pipeline capacity additions and some additional transmission capacity compared to the "Constrained" case, which assumes no future capacity through the study period.

A Monte-Carlo simulation was conducted based on this model and several key variables were modeled as distributions rather than as fixed values in the simulation. The variables modeled as distributions were LDC pipeline demand, electric demand for gas and gas basis price. In the simulation, three output variables were tracked: pipeline headroom, natural gas delivered price and LMP. The simulation was run for 10,000 draws, which allowed for analysis of the possible outcomes for the four scenarios. The strength of using a Monte-Carlo simulation is that the output is a range of outcomes that are possible from the distribution of inputs. For that reason, it is a useful tool for understanding the risks and potential benefits of a decision under highly uncertain conditions. There are many more complex tools available for modeling LMPs including production cost models, which model resources and loads to a much greater degree of detail than the model created for this study.

# ASSUMPTIONS

## Natural Gas Supply

To determine the potential natural gas supply in New England, current pipeline capacity and future additions were examined. The amount of future additional pipeline capacity varied based on the two scenarios modeled.

### Current Pipeline Capacity

Current pipeline capacity is based on data from the financial information and data collection firm SNL.[39] Data were gathered on the scheduled (versus maximum) delivery capacity for gas pipeline points in New England classified by three distinct point types from January 1, 2011 to June 9, 2015. The point types include "Plant," the point at which gas is received from a gas processing plant via a pipeline, "Delivery to LDC," point at which gas is delivered to a local distribution company, and "Delivery to an End User," point at which gas is delivered to an end user, typically customers that are large enough to receive their natural gas directly from the pipeline. The data collected represents the daily average for each point. The NAESB (North American Energy Standards Board) cycle "Intraday 2" was selected to represent the daily capacity. This cycle is nominated at 5:00pm the day the gas flows, confirmed at 8:00pm the day the gas flows, and the schedule quantity is available by 9:00pm the day the gas flows.

Daily capacity for the three point types was totaled by gas pipeline. The result was a historical dataset of daily scheduled capacity for the five gas pipelines serving New England: Algonquin Gas Transmission L.L.C., Iroquois Gas Transmission System L.P., Portland Natural Gas Transmission System, Maritimes and Northeast Pipeline L.L.C., and Tennessee Gas Pipeline Company L.L.C. To determine the total maximum pipeline capacity for New England, the maximum daily scheduled capacity for each pipeline was identified by year, which occurred during different days throughout the year, and added the five data points together. The result was a maximum New England pipeline capacity for each year. Since this amount has remained relatively constant since 2011, the 2015 maximum New England pipeline capacity was kept constant through the study period.

Calculations are shown below for the maximum daily pipeline capacity for New England by calendar year. The example is for one of the years, below labeled "y1." "da," "db," etc., are meant to represent different days with no particular order throughout "y1."

$$\mathrm{Max(PC)}d,y_1 = \mathrm{Max(AGT)}d_a,y_1 + \mathrm{Max(IGTP)}d_b,y_1+\mathrm{Max(PNGTS)}d_c,y_1+\mathrm{Max(MNP)}d_d,y_1+\mathrm{Max(TGPC)}d_e,y_1$$

- where:
- PC= Pipeline Capacity
- AGT= Algonquin Gas Transmission L.L.C.
- IGTP =Iroquois Gas Transmission System L.P.

[39] SNL Financial, "About Us." https://www.snl.com/About-Us.aspx?name=aboutSNL

- PNGTS =Portland Natural Gas Transmission System
- MNP =Maritimes and Northeast Pipeline L.L.C.
- TGPC =Tennessee Gas Pipeline Company L.L.C.

**Future Additions**

Two scenarios were modeled: an "Unconstrained" case and a "Constrained" case. For the Constrained case, no future pipeline capacity additions were assumed. For the "Unconstrained" case, a total of 1.695 Bcf/day was added by winter 2018-2019, as discussed in Appendix C.

The analysis does not include any explicit provision for injections of LNG outside of those embedded in the historical price and pipeline flow data. The effect of such injections, were they to occur, is largely indistinguishable from the effect of natural gas-fired units turning to distillate fuel oil as an alternative to gas when the pipelines are constrained for the purposes of the current modeling effort.

## Natural Gas Demand

New England daily gas demand is calculated as: [LDC Demand] + [Electric Generator Demand] – [Gas Demand Offset by Additional Imports and Renewable Development]. From the SNL dataset described in the Current Pipeline Capacity section, LDC Demand and Electric Demand from January 1, 2011 to June 9, 2015 were used. LDC Demand is defined as the scheduled capacity for delivery to LDCs and end users. Electric Demand is defined as the scheduled capacity for delivery to power plants.

For both LDC Demand and Electric Demand, the capacity scheduled for the summer seasons 2011-2014 and winter seasons 2012-2015 were identified. From these datasets, distributions for LDC Demand and Electric Demand for summer and winter were developed based on the distributions with the best goodness of fit values (such as Anderson-Darling and Chi-Square P-Value). A lognormal distribution was selected for summer LDC Demand and a beta distribution for winter LDC Demand. For both winter and summer, LDC Demand was assumed to grow by 1% each year. A beta distribution was selected for summer Electric Demand and a logistic distribution for winter Electric Demand. For both winter and summer, Electric Demand was assumed to grow by 3.5% each year based on projected natural gas capacity additions. Below are the images of four distributions.

FIGURE B-17: SUMMER LDC PIPELINE DEMAND (MCF/DAY)

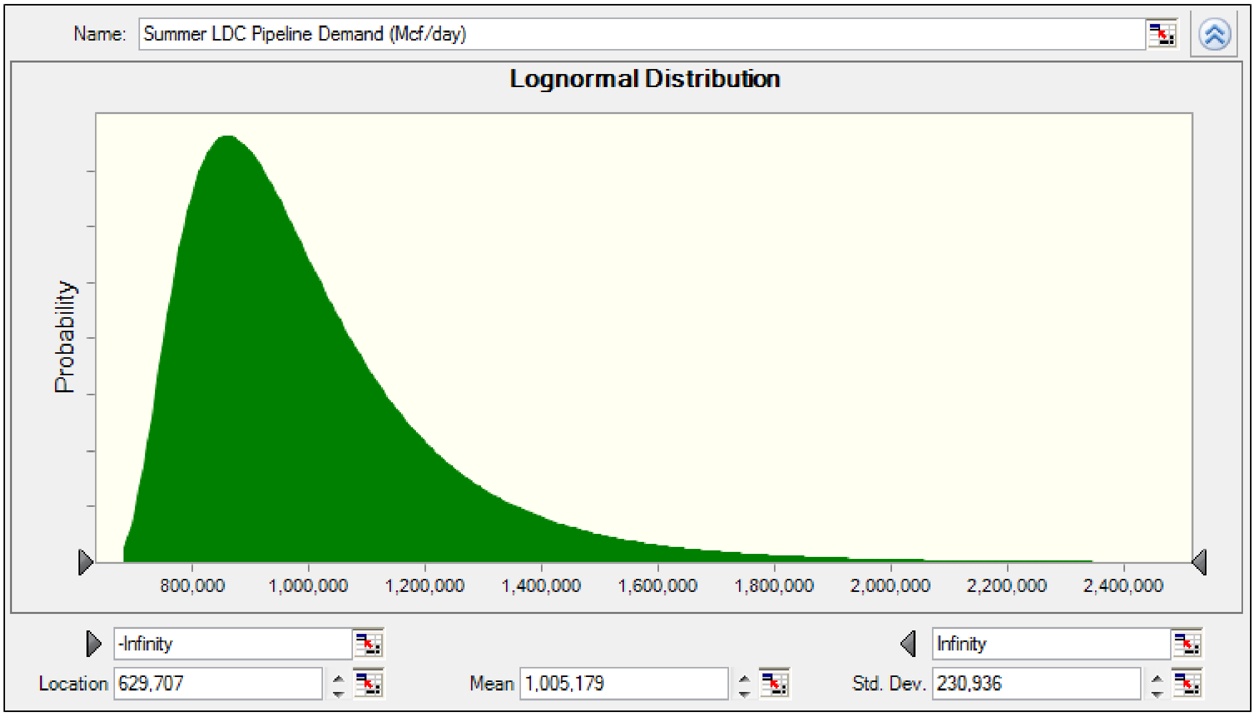



FIGURE B-18: WINTER LDC PIPELINE DEMAND (MCF/DAY)

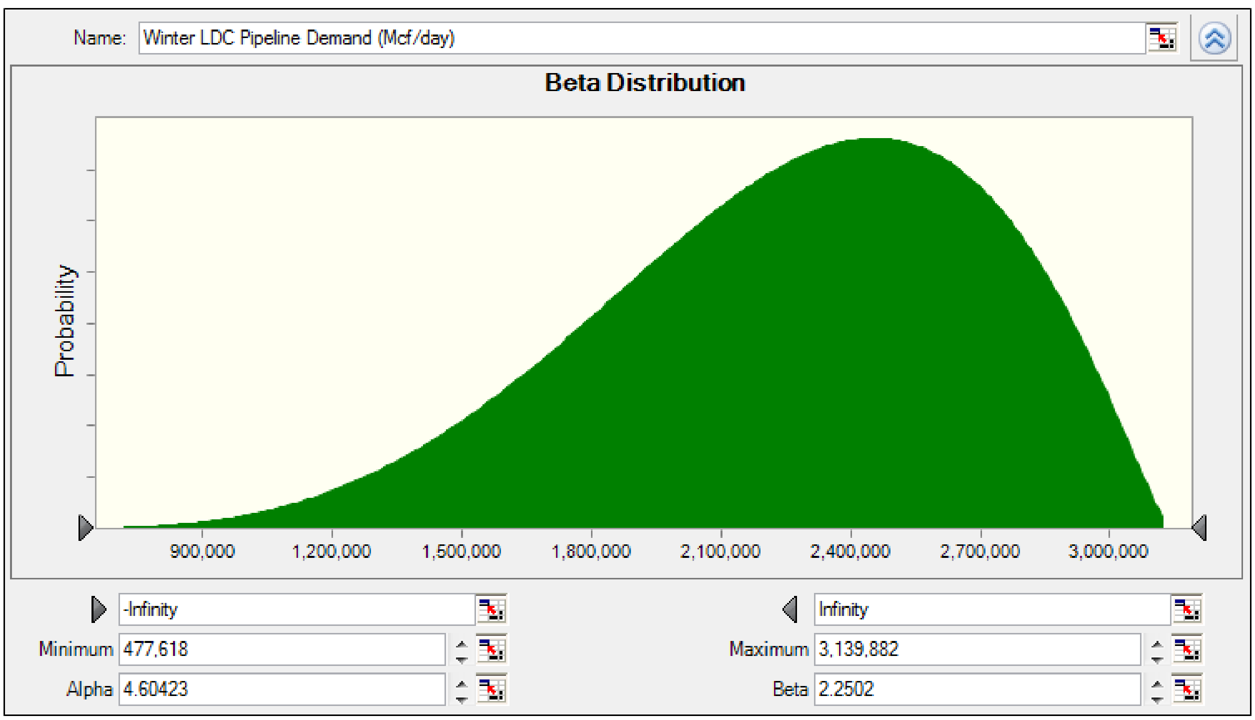


FIGURE B-19: SUMMER ELECTRIC DEMAND (MCF/DAY)

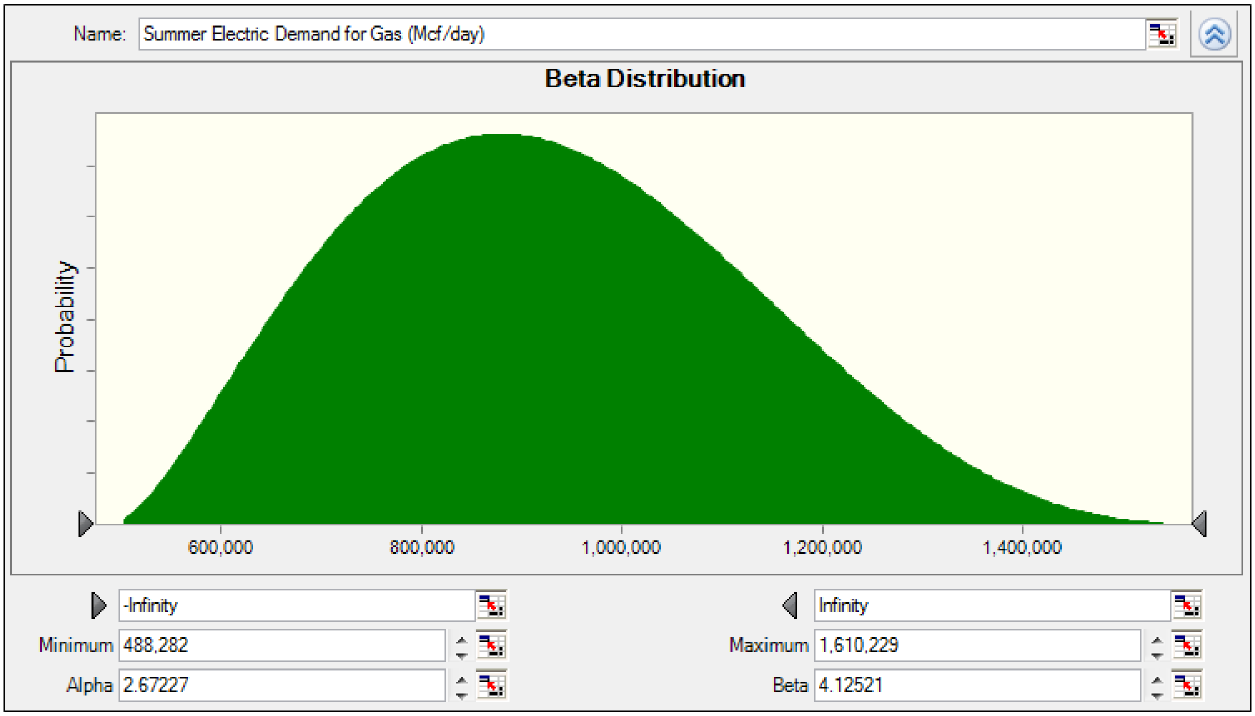
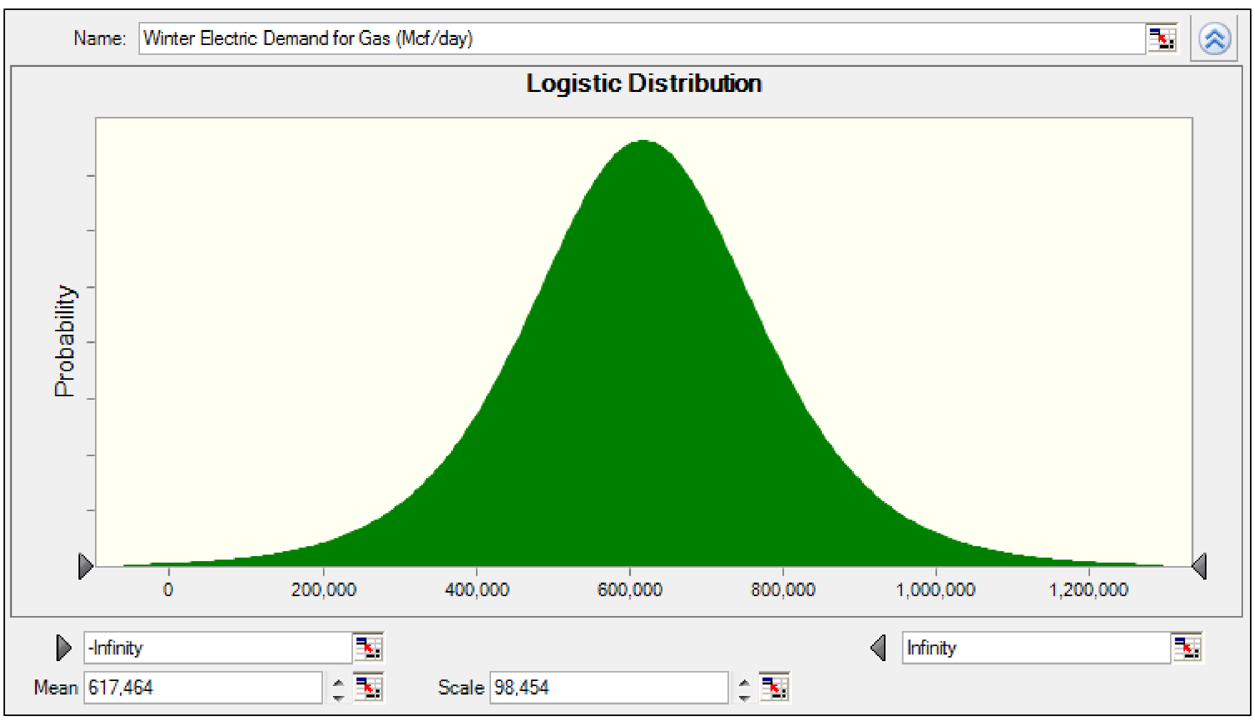



FIGURE B-20: WINTER ELECTRIC DEMAND (MCF/DAY)



An additional import capacity of 500 MW was included for the "Unconstrained" case starting in winter 2018. For both cases, a renewable buildout was included to forecast the addition of renewable capacity by 2021. This additional capacity, from imports and renewables, was subtracted from the natural gas demand using a natural gas heat rate to convert the capacity into units of Mcf/day.

## Pipeline Headroom

Pipeline headroom is defined as the difference between natural gas supply and natural gas demand delivered by the pipeline system. It is a key input to the Monte-Carlo simulation because the historical relationship between headroom and natural gas basis drives the natural gas price simulation.

### Historical Pipeline Headroom

Historical daily headroom was calculated as the difference between the total scheduled capacity for the five pipelines for that day and the aforementioned maximum New England pipeline capacity for that year. The calculation is shown below for the daily headroom for New England by year. The example is for one of the years, below labeled "y1." "da," "db," etc. are meant to represent different days with no particular order throughout "y1."

$$HR\ d_x,y_1 = Max(PC)\ d,y_1 - ((AGT)d_x,y_1 + (IGTP)d_x,y_1 + (PNGTS)d_x,y_1 + (MNP)d_x,y_1 + (TGPC)d_x,y_1)$$

- where:
- PC= Pipeline Capacity
- HR= Headroom
- AGT= Algonquin Gas Transmission L.L.C.
- IGTP =Iroquois Gas Transmission System L.P.
- PNGTS =Portland Natural Gas Transmission System
- MNP =Maritimes and Northeast Pipeline L.L.C.
- TGPC =Tennessee Gas Pipeline Company L.L.C.

### Natural Gas Basis

The natural gas basis difference between gas delivered to TETCO M-3[40] and gas delivered to New England was modeled as a function of pipeline headroom. Historical natural gas spot prices were sourced from the financial information and data collection firm SNL. SNL gathered the prices from the NYMEX market data provided by DTN Energy Services. The historical basis was calculated as the difference in the prices published at TETCO M-3 and Algonquin Citygate. Daily prices from January 1, 2011 to June 9, 2015 were used, which excludes holidays and weekends when trading does not occur.

[4040] TETCO M-3 is "located" in Eastern Pennsylvania.

The relationship between headroom and basis was studied by matching daily headroom as described above and natural gas prices from that day. After sorting the dataset by headroom from least to greatest, the headroom values were grouped with their associated natural gas prices into six bins. The bins are defined according to the table below.

TABLE B-11: BIN DEFINITIONS

| Bin Number | Headroom Range |
|---|---|
| 1 | <300000 |
| 2 | <600000 |
| 3 | <900000 |
| 4 | <1200000 |
| 5 | <1500000 |
| 6 | >1500000 |

A distribution for each bin (except Bin 1 and 2, which were grouped) was developed based on the headroom and natural gas values in that particular bin. The same goodness of fit values were consulted for the selection of the distribution. The lognormal distribution was selected for each bin, but each had unique variable inputs. Therefore, a calculated headroom value directs the model to a certain basis price distribution.

## Locational Marginal Price Calculation

The LMP was calculated by multiplying the cost of electricity for resources on the margin by the amount of time that resource is expected to be on the margin. The gas price was developed as the sum of a proprietary Henry Hub price forecast and the basis price as calculated by the model and described above. Because the basis price is defined as the difference between TETCO M-3 and Algonquin City gates, TETCO M-3 and Henry Hub prices were assumed to converge in the next few years (consistent with trends in forward market pricing).

The average non-gas cost of electricity that was used in the modeling is shown in the table below.

TABLE B-12: AVERAGE NON-GAS COST OF ELECTRICITY ($/MWH)

| 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| $116.12 | $92.43 | $95.17 | $94.40 | $95.47 | $98.97 | $100.88 | $103.19 |

Historical data from ISO-NE Quarterly Markets Reports was used to develop an estimate of what percentage of time gas and non-gas resources would be on the margin. A phasing out of coal was assumed by the summer of 2019 and the winter of 2020, and of oil by summer 2020 and winter 2021. The phasing out of these two resources on the margin coincides with an increase in natural gas on the margin. The table below summarizes the percentages as used in the model.

TABLE B-13: MARGINAL FUEL FOR GENERATION, % OF HOURS

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|
| Gas (summer) | 83% | 84% | 87% | 87% | 87% | 87% | 87% | 87% |
| Non-gas (summer) | 17% | 16% | 13% | 13% | 13% | 13% | 13% | 13% |
| Gas (winter) | 55% | 64% | 66% | 68% | 71% | 74% | 77% | 80% |
| Non-gas (winter) | 45% | 36% | 34% | 32% | 29% | 26% | 23% | 20% |

Currently there are about 4,000 MW of primary natural gas resources that can also burn oil. When the price of natural gas reaches the price of distillate oil, these dual-fueled units are assumed to burn oil. This was accounted for in the model by changing the marginal resource percentage when the price of natural gas is greater than or equal to the price of distillate oil. When this happens the marginal percentage of distillate oil units is assumed equal to the fraction of natural gas units that are dual-fueled multiplied by the marginal resource percentage of natural gas units. The assumption of additional 3,500 MW of dual-fuel capability as a result of the ISO-NE winter program in 2015 and an additional 2,500 MW in 2019 when the FCM Pay-for-Performance rules go live was used.

# APPENDIX C – ENERGY COST ANALYSIS: ADDITIONAL DETAILS

In this Appendix, additional details and background underlying the assumptions and approach to the analysis of energy costs are discussed.

# NATURAL GAS AND PIPELINE INVESTMENTS

Natural gas is used by both electric generators and end users, such as households and businesses. Hence, pipeline investments will have impacts on natural gas costs paid by end users and electric costs paid by end users, given that electric generators use natural gas to power their facilities. The analysis of infrastructure gaps on natural gas prices is calculated first because of the extensive use of natural gas as a generating fuel, which has direct impacts on the electricity prices paid by consumers (discussed in the next section).

The first basic step in the analysis is to understand how natural gas prices are impacted by the expansion (or lack thereof) of natural gas pipelines. The pipeline expansion and their online dates (November of the split year), applicable to the summer and winter models, that was assumed in the analysis are shown in the table below. Pipelines are "fully built" in November 2018/19 at a level of 1.695 Bcf/Day.

TABLE C-14: GAS PIPELINE ADDITIONS (BCF/DAY) FOR UNCONSTRAINED CASE IN SUMMER AND WINTER MODELS

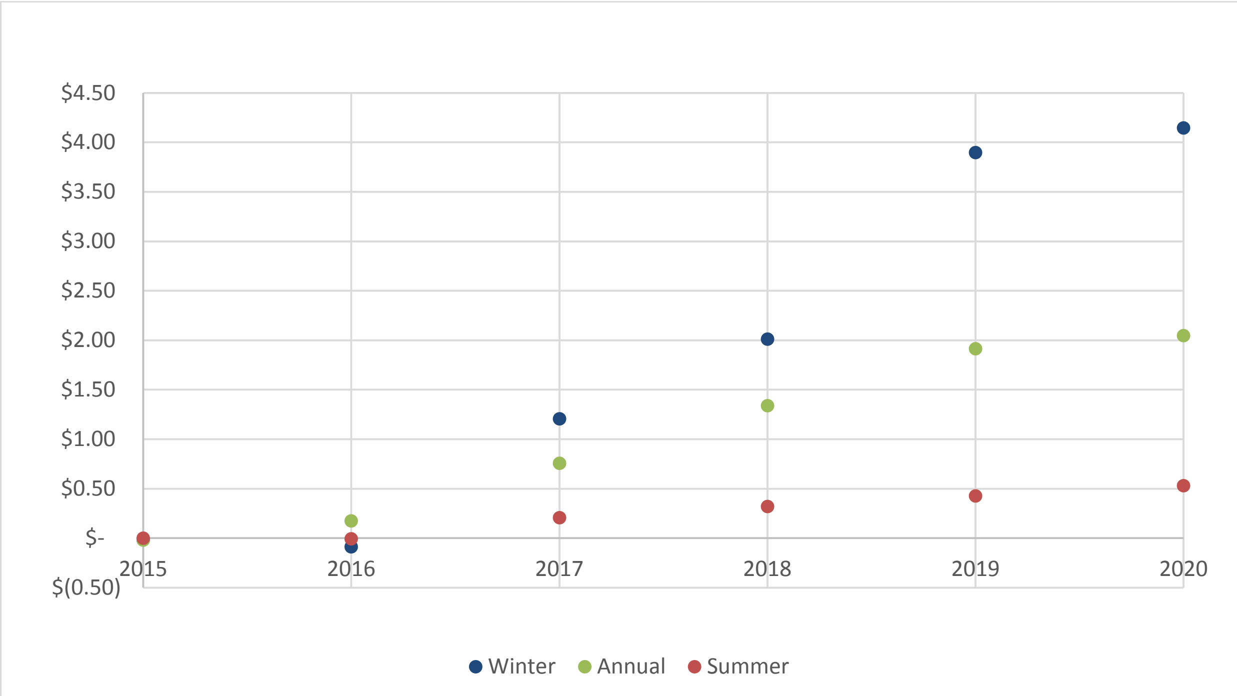
| Projects | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 |
|---|---|---|---|---|---|---|
| Project A | 0 | 0.342 | 0.342 | 0.342 | 0.342 | 0.342 |
| Project B | 0 | 0 | 0 | 0.7 | 0.7 | 0.7 |
| Project C | 0 | 0 | 0.153 | 0.153 | 0.153 | 0.153 |
| Project D | 0 | 0 | 0 | 0.5 | 0.5 | 0.5 |

Though the modeling did not include selection of specific projects, the level and timeline of expansion was based on a review of the proposed pipeline projects discussed in the Appendix A. The proposed pipelines potentially feature a larger expansion than was modeled here, but this level was selected based on our review of development efforts to date and the impacts of different expansion levels on prices.

## *PIPELINE AND TRANSMISSION EXPANSION IMPACTS*

The chart below represents the difference in the basis prices between the two cases for winter, summer and annually. Basis price differences on an annual basis were found by weighing the seasonal values. Note that the winter season is defined as November through the following March, but is designated in the figure based on the year corresponding to March of the year.

FIGURE C-21: CONSTRAINED AND UNCONSTRAINED CASE BASIS PRICE DIFFERENCE FOR WINTER, SUMMER AND ANNUAL



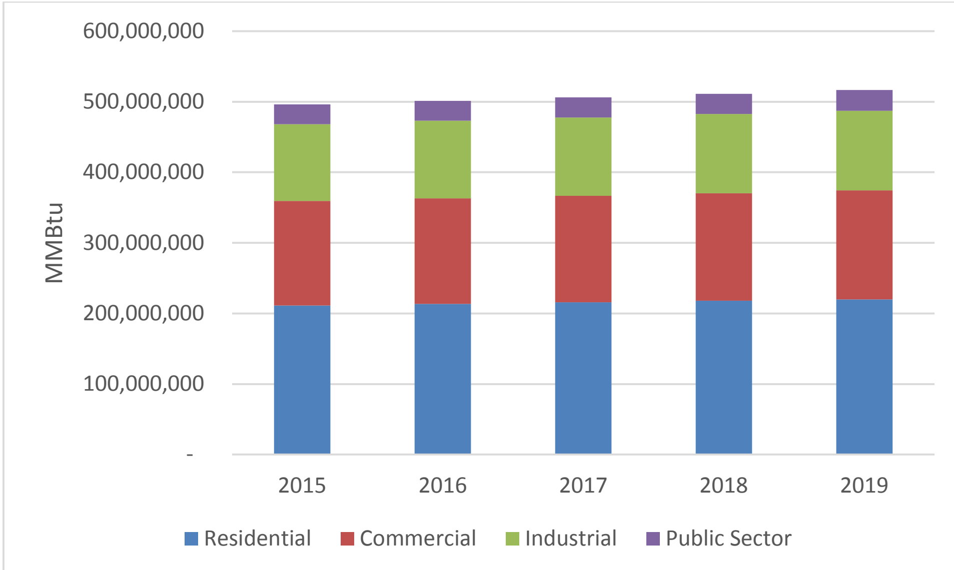

The modeling results above assumed that there would be impacts even in the summer months when pipelines are not congested. This result is consistent with the data in our historical period, which did feature positive differences between the Algonquin citygate prices and prices outside the region (as shown in the TETCO M-3 prices).[41]

## IMPACTS ON NATURAL GAS COSTS

In order to calculate the impact on costs paid by natural gas customers (excluding use by generation facilities) in the region, the amount of throughput not used for electric generation over the study period was forecasted. Forecasts from the Energy Information Administration for New England were used to determine the amount of throughput over the study period, and the assumption of 1% growth, which is conservative. The figure below shows the forecast of throughput over the study period.

[41] The impact on prices assuming no summer impact was also modeled. The cost savings results did not change significantly and did not alter the conclusions of significant cost reductions from expanding pipeline.

FIGURE C-22. FORECASTED NATURAL GAS DEMAND, 2016-2020




The assumptions regarding the impacted portion of this throughput are more important. For this analysis different assumptions were used for the period 2016-2018, before the full pipeline buildout, and 2019-2020, when the full pipeline buildout is in place. For the years 2016-2018, an estimate of 20% of annual regional consumption was used for non-residential customers and 5% was used for residential customers. These estimates are based on assumptions concerning the percentage of existing customers that are "capacity-exempt" and thus do not have access to LDCs' portfolios[42], the use of locally priced natural gas to supplement existing capacities during time of winter peaks, and the customers in locations where locally priced gas is prevalent.

For the years 2019 and 2020, when the full pipeline buildout is assumed, regulatory filings in Massachusetts by the LDCs seeking approval of long-term contracts with some of the pipeline projects discussed in the Appendix A provided information for possible cost impacts. The cost impacts on LDCs' existing (and future) portfolios to meet normal heating loads and certain load factor assumptions were used to extrapolate impacts to New England for the infrastructure expansion level relevant to each year. The estimates of increased natural gas costs due to lack of infrastructure development are shown below.

[42] Natural gas utilities or local distribution companies ("LDCs"), in contrast to electric generators, are monopolies with exclusive franchise territories. Thus, they are regulated in both their delivery operations and gas purchasing strategies and receive cost recovery with an allowed rate of return. This regulatory framework allows (and requires) the utilities to take certain actions that otherwise may not have been taken by firms facing competitive pressures, such as electric generators and competitive energy (electricity and natural gas) suppliers. In particular, natural gas utilities have purchasing and hedging strategies that include purchase of capacity, storage and liquefied natural gas ("LNG") contracts that form a supply portfolio. Capacity-exempt customers are customers that have chosen to shop with a competitive supplier and thus do not have access to these LDC supplies.

TABLE C-15. NATURAL GAS COSTS (CONSTRAINED - UNCONSTRAINED), MILLIONS OF 2014$

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **Residential** | $2.26 | $8.58 | $14.25 | $131.40 | $128.76 |
| **Commercial** | $6.34 | $24.01 | $39.89 | $91.98 | $90.13 |
| **Industrial** | $4.66 | $17.64 | $29.31 | $67.58 | $66.22 |
| **Government** | $1.20 | $4.53 | $7.53 | $17.36 | $17.01 |
| **Total** | $14.45 | $54.76 | $90.96 | $308.32 | $302.12 |

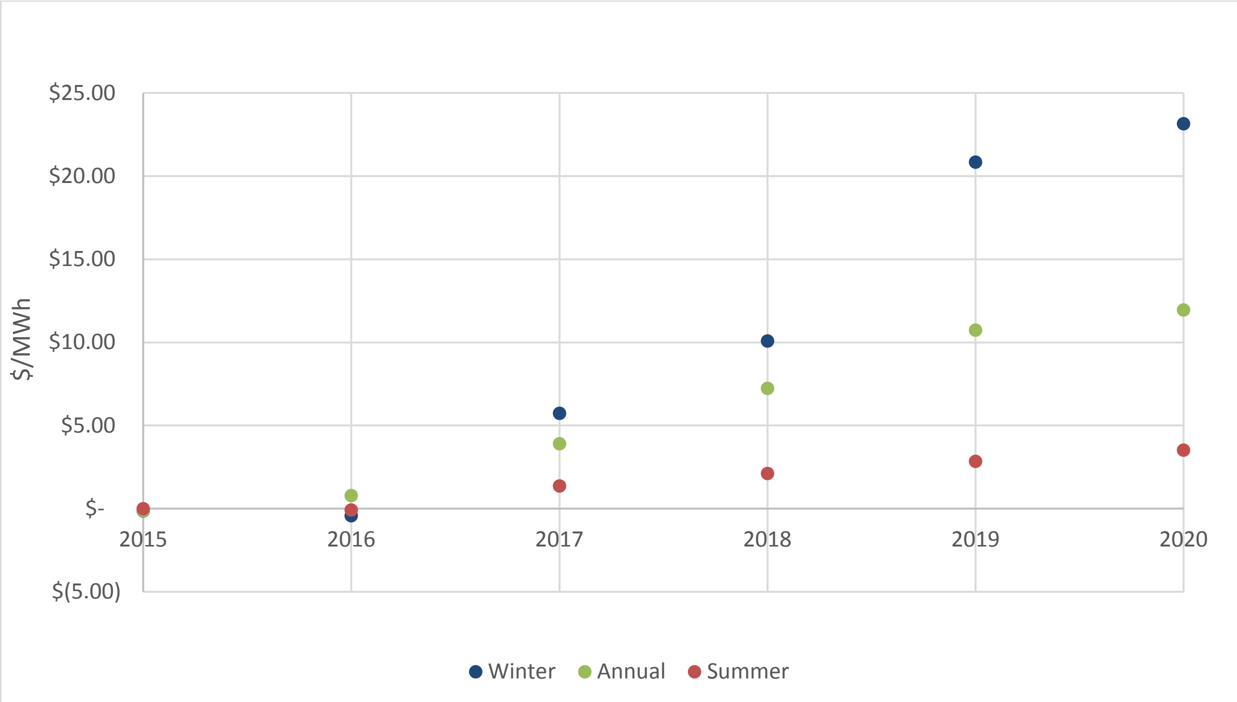
# ELECTRIC ENERGY MARKET IMPACTS

The model discussed above for natural gas also forecasts electric energy prices. The model focuses on resources on the margin, which set locational marginal prices (“LMPs”). The percent of time resources were on the margin for winter and summer in the ISO-NE Quarterly Markets Reports was utilized for the analysis—thus, when gas is priced high during winter months, the generation mix switches to other fuels (notably distillate fuel oil).  LMPs for summer and winter were calculated by multiplying the cost of electricity for resources on the margin by the amount of time that resource is expected to be on the margin. See Appendix B for further description of the model structure and assumptions.

## *PIPELINE EXPANSION IMPACTS*

The chart below illustrates the forecasted difference in LMPs between the two cases.

FIGURE C-23: DIFFERENCE IN LMPS BETWEEN CONSTRAINED AND UNCONSTRAINED CASES




## TRANSMISSION EXPANSION IMPACTS

The addition of 500 MW of transmission that allows additional imports from neighboring regions has the potential to impact the prices and costs paid by New England ratepayers. The selection of 500 MW was based on one possible outcome of the joint procurement efforts by the 3 southern New England states and taking into account the likelihood of such a transmission project being operational by 2020. A review of the interconnection queue at ISO-NE shows many more MW that have filed interconnection requests. Similarly, there has been mention of legislation to expand import capability to much higher levels than assumed here[43]. It is important to remember that expansion of import capability and natural gas expansion act as substitutes, thus expansion of pipeline will reduce the impacts of expanded import capability (and vice versa). Therefore, a higher relative expansion of pipelines was assumed due to an assessment of the likelihood of pipeline expansion compared to import expansion over the study period.

Failure to add such infrastructure similarly has the potential to increase costs paid by New England ratepayers. As with the pipeline infrastructure discussion above, particular assumptions about how this transmitted power interacts with other market participants is crucial. Where these assumptions do not hold, then impacts will be different from those shown here.

The crucial assumption to enable impacts is that the energy delivered via the transmission lines features low (or no) variable costs, such as in the case of wind or hydro, and thus is able to be bid in prices at lower

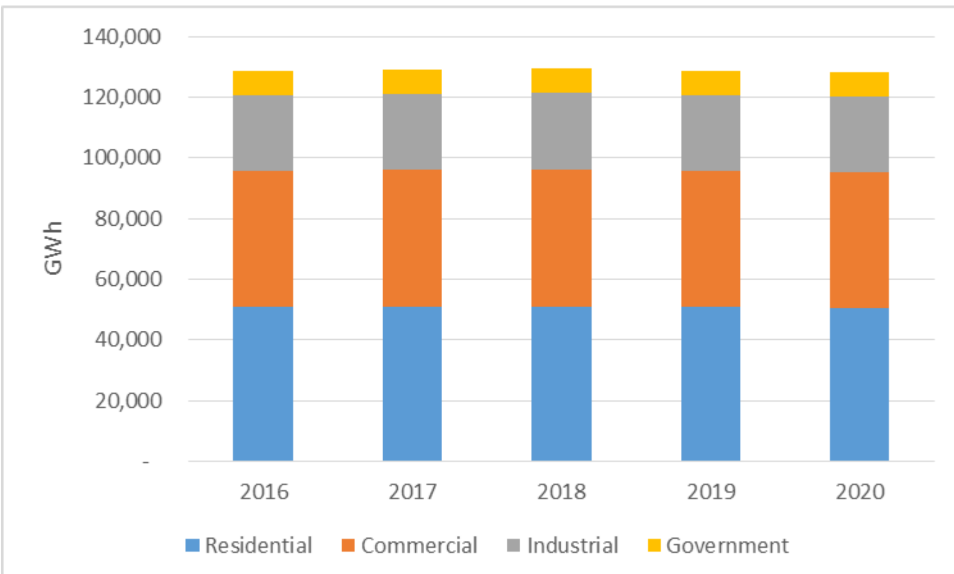
[43] https://malegislature.gov/Bills/189/Senate/S1965

levels than current marginal units (notably powered by natural gas, as discussed above). Prior studies have also analyzed the impact of transmission facilities on LMPs[44]. In particular the percentage change in LMPs forecasted by the studies was utilized. The 2010 study forecasted impacts ranging from 2.4% and 3.2% of "base case" prices, while the 2012 study featured a range of 1.9% to 2.4%. The reduction in percentages was due to different assumptions, notably the cost of natural gas, which was much lower in the 2012 study. For purposes of this study, the lower range of impacts was assumed given that addition of pipelines is expected to exert further downward pressure on electricity prices.

## IMPACTS ON ELECTRIC ENERGY COSTS

In order to calculate cost impacts, the total $/MWh cost impact of pipeline and transmission infrastructure is multiplied by an assumption of electricity demand over the study period. The figure below shows the forecast assumed for wholesale electricity demand over the study period.

FIGURE C-24. NET ENERGY LOAD FORECAST, 2016-2020.




The forecast is based on ISO-NE forecasts from the 2015 Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report), specifically the forecast that accounts for energy efficiency and behind the meter solar installations. Incorporation of these measures contributes to the relatively flat (and decreasing in later years) outlook for electricity demand. This outlook for electric energy consumed over the year is much different for the demand for "capacity" is discussed below.

Table C-16 shows the cost impacts on electric energy costs.

[44] "LMP and Congestion Impacts of Northern Pass Transmission Project – Final Report", Charles River Associates, December 2010 and "Electricity Market Impacts of the Northern Pass Transmission Project", PA Consulting Group, June 2012.

TABLE C-16. ELECTRIC ENERGY COSTS (CONSTRAINED – UNCONSTRAINED), MILLIONS OF 2014$

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **Residential** | $51.86 | $209.62 | $370.73 | $517.06 | $552.77 |
| **Commercial** | $45.92 | $185.63 | $328.30 | $457.89 | $489.51 |
| **Industrial** | $25.47 | $102.96 | $182.09 | $253.96 | $271.50 |
| **Government** | $8.12 | $32.84 | $58.08 | $81.00 | $86.59 |
| **Total** | $131.38 | $531.04 | $939.20 | $1,309.90 | $1,400.37 |

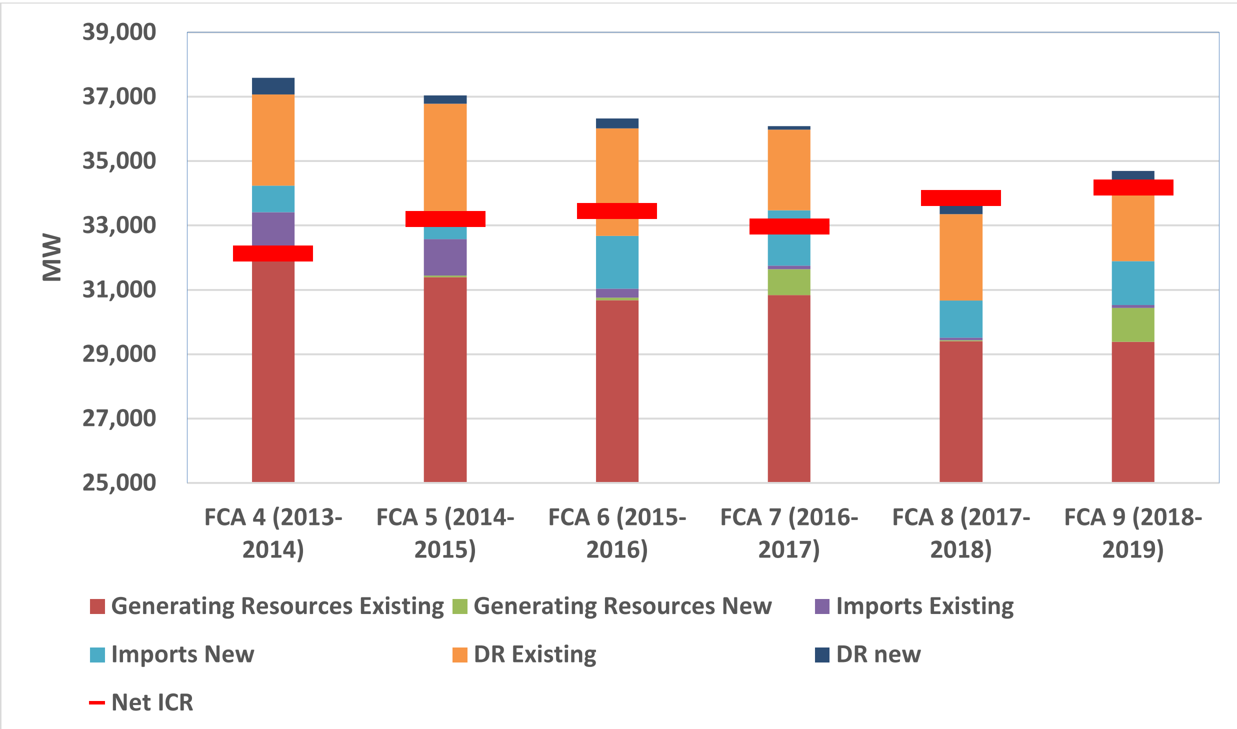
## ELECTRIC CAPACITY IMPACTS

The Forward Capacity Market (FCM) is a wholesale capacity market administered by the regional operator ISO New England (ISO-NE). The market is designed to: (a) provide a long term commitment (recently updated to seven years) to new supply resources to encourage new investment; (b) procure enough capacity to meet forecasted demand and installed reserve requirements in New England; (c) used a descending clock auction that incorporates a sloped demand curve to select a portfolio of resources to meet the capacity requirement, and (d) compensate the cleared resources with the market clearing price of capacity. The current basic structure of New England's capacity market was developed as a result of a settlement agreement between various regional stakeholders and was approved by the Federal Energy Regulatory Commission (FERC) in 2006. However, market rules related to capacity markets have changed over time and were incorporated into the analysis of future FCM prices.

The primary goal of the capacity market in New England is to procure enough capacity for a specific commitment period, which spans from June 1st to May 31st of the following year, to meet the installed capacity requirement (ICR) calculated by ISO-NE. The existing structure includes a primary Forward Capacity Auction (FCA), which is held approximately three years prior to the commitment period and a number of following auctions, called reconfiguration auctions (RA), which take place before and during the commitment period and allow market participants to shed their existing capacity or obtain new capacity. In addition, the RAs assist ISO-NE in procuring additional capacity needed for various reasons such as inefficient capacity cleared in the primary auction or updates to ICR between the completion of the FCA and the start of the commitment period. Besides the reconfiguration auctions, the capacity market provides the ability to conduct bilateral transactions between participants on specific timeframes. Bilateral transactions and RA are two mechanisms by which existing commitments can be replaced.

The figure below denotes how the capacity resources have compared versus the capacity target in each of the last 6 Forward Capacity auctions (FCA). In the first four Auctions (FCA 4 – FCA 7) the market is at a capacity surplus, where the summation of existing and new capacity is above the Net ICR, which is each capacity Auction's target. In FCA 8, the region did not have enough capacity to meet its capacity target resulting in a market capacity deficit. The latest FCA, held in February, 2015 procured more than the auction capacity target, but as the figure below denotes, the excess capacity is not significant like it was in FCA 4 through 7. The small capacity surplus seen in FCA 9 makes the market more susceptible to fall back in a capacity shortage if a small amount of the existing resources exits the market and no new capacity enters the market.

FIGURE C-25. CAPACITY RESOURCES, 2013-2019




The significant capacity excess in New England prevented any new generation to enter during the first years of the capacity market. This changed after FCA 7, when after a significant amount of existing resources retired. Besides the retirement of existing generating resources, the capacity market lost a significant amount of Demand Resources that were available in the earlier years for a variety of reasons, such as stricter ISO-NE market rules pertinent to these resources. As a result, FCA 8 did not procure enough capacity to meet its goals and prompted the entrance of new generating resources of close to 1400 MW in FCA 9 to satisfy the need.

In February 2015, ISO-NE completed FCA 9 – the latest primary annual auction - for the 2018-2019 commitment period. The auction resulted in 34,695 MW clearing the auction, which is close to 500 MW more than the system wide ICR calculated by ISO-NE. The cleared capacity the addition of 1400 MW of new resources that included the construction of a new 725 MW generator in Connecticut and a 195 MW peaking power plant in Southeast Massachusetts – Rhode Island. The analysis here focuses on the capacity market impact as a result of these two projects not materializing. Similar impacts would occur if an equal amount of MWs retire and elect not to participate in capacity auctions for the 2019-2020 (FCA 10) and 2020-2021 (FCA 11) commitment periods. No impacts were included from the period prior to June 2019.

The capacity impact analysis compared two scenarios (constrained and unconstrained) in evaluating the impact of the two units removed from the market (constrained) in the upcoming FCA 10 and FCA 11 versus not (unconstrained). Since FCA 9 is completed and the two units have an obligation to meet, their inability to become available to the wholesale market will affect their owners and not the ratepayers for the FCA 9 commitment period. The lost capacity will be replaced by other market participants that have unsold capacity in the RAs or through bilateral transactions and the owners of the two generators will bear financial risk of these transactions.

In order to provide a clear assessment of the potential impacts that occur if currently planned facilities of approximately 920 MW are not built or are delayed, the analysis assumed the following in both scenarios: (i) No new entry in FCA 10 and FCA 11 despite high clearing prices in the constrained scenario; (ii) additional clearing of 131 MW in FCA 10 and 45 MW in FCA 11 of renewables; (iii) Imports remain constant in FCA 10 and FCA 11 at similar MW level to FCA 9[45]; and (iv) additional energy efficiency clearing the capacity market to comply with ISO-NE's forecast as provided in the 2015 CELT report. The results of the two scenarios are denoted in the table below:

TABLE C-17. CAPACITY MARKET COSTS UNDER CONSTRAINED AND UNCONSTRAINED CASES

| | Constrained | | | Unconstrained | | |
|---|---|---|---|---|---|---|
| | MW | FCA Price ($/kw-Month) | Capacity Revenue (million $) | MW | FCA Price ($/kw-Month) | Capacity Revenue (million $) |
| FCA10 (2019-2020) | 34,170 | $12.63 | $5,178.22 | 35,221 | $7.70 | $3,253.57 |
| FCA11 (2020-2021) | 34,401 | $13.53 | $5,583.96 | 35,497 | $8.34 | $3,551.63 |

Since the capacity commitment periods span over two calendar years, the impact of the 920 MW was calculated on a calendar year basis to provide a more consistent picture when comparing with the other components of the overall energy price impacts The costs allocated to the relevant customer groups for input to REMI are shown below.

[45] 500 MW transmission import facility was assumed to not clear the capacity market given the entry of the generation discussed above and the possibility of mitigation by ISO-NE. If the facility were to clear the market, cost impacts would be greater than shown in

Table C-18.

TABLE C-18. ELECTRIC CAPACITY COSTS (CONSTRAINED - UNCONSTRAINED), MILLIONS OF 2014$

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **Residential** | $0.00 | $0.00 | $0.00 | $406.67 | $705.42 |
| **Commercial** | $0.00 | $0.00 | $0.00 | $360.13 | $624.69 |
| **Industrial** | $0.00 | $0.00 | $0.00 | $199.74 | $346.48 |
| **Government** | $0.00 | $0.00 | $0.00 | $63.71 | $110.51 |
| **Total** | $0.00 | $0.00 | $0.00 | $1,030.25 | $1,787.10 |

The capacity market impact for calendar year 2019 is forecasted to be close to $1 billion in 2019 and close to $1.8 billion in 2020 for a total of about $2.8 billion over the two year period.

# RPS MARKET IMPACTS

In New England, Renewable Portfolio Standards place certain purchase requirements on load serving entities (“LSEs”). LSEs can be regulated distribution utilities that still provide generation service to certain customers that have not migrated to competitive retail supply. LSEs can also be competitive suppliers that currently provide retail supply to commercial, industrial, and residential customers. Requirements are stated in a minimum percentage of total electricity supply per year and can be met with energy produced by RPS-qualified generators. Given that RPS requirements are a function of load levels, the Massachusetts and Connecticut markets provide the large majority of compliance-related demand from New England.

Renewable portfolio standards in New England contain various “classes” of RECs for which compliance is required. As used in this report, “Premium Class I REC markets” refers to Massachusetts (“MA”) Class I, Connecticut (“CT”) Class I, Rhode Island (“RI”) new, and New Hampshire (“NH”) Class I and II. Though significant eligibility differences apply (particularly CT Class I), the markets are fungible enough to be thought of generally as a single market.

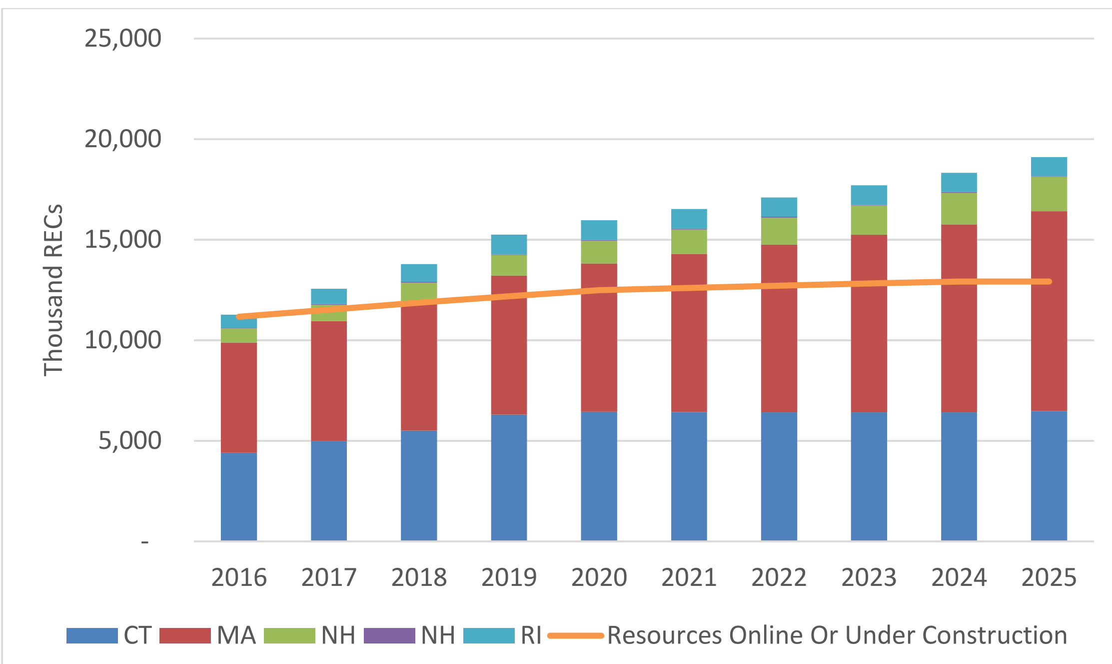
Compliance entities must purchase class-eligible RECs equivalent to a certain percentage of obligated load by a certain date each year. All four states allow some form of REC “banking”, enabling compliance entities to apply a limited number of surplus RECs toward future obligations. The table below summarizes the minimum percentage requirements by class and year for the 2016-2020 time period.

TABLE C-19. PREMIUM RPS CLASS MINIMUM PERCENTAGE REQUIREMENTS, 2016-2020

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **CT Class 1** | 14% | 15.5% | 17% | 19.5% | 20.0% |
| **MA Class 1** | 11% | 12% | 13% | 14% | 15% |
| **NH Class 1** | 6.9% | 7.8% | 8.7% | 9.6% | 10.5% |
| **NH Class 2** | 0.3% | 0.3% | 0.3% | 0.3% | 0.3% |
| **RI New** | 8.0% | 9.5% | 11.0% | 12.5% | 12.5%[46] |
| **Load-Weighted Average** | 11.2% | 12.4% | 13.6% | 15.1% | 15.9% |

For this study, the infrastructure buildout was calculated in terms of the amount of onshore wind[47] MW that would be necessary to meet the unfulfilled requirements shown in Figure C-26.

FIGURE C-26. NEW ENGLAND RENEWABLE ENERGY REQUIREMENTS AND SUPPLY




[46] Maintained in 2020 and thereafter unless determined otherwise by regulators.

[47] Other resource types, such as off-shore wind and solar can be used to meet the RPS requirements. A solar buildout was assumed in the supply, and offshore wind remains cost-prohibitive compared to onshore wind. As a result, only use of onshore wind was examined.

As can be seen in the figure, supply is close to demand in 2014, but the gap increases throughout the study period and beyond. The expansion of solar in Massachusetts through the SREC I and SREC II programs (and in other states), imports from Quebec and New York, and renewable resources that are online or far along in the development process were included. Even accounting for these resources (many of which resulted from state-level programs or procurements), demand for RECs is expected to exceed supply.

The gap between supply and demand in the figure can be translated into number of MW (nameplate) of wind resources by assuming a capacity factor. For example, use of a 30% capacity factor yields the following buildout:

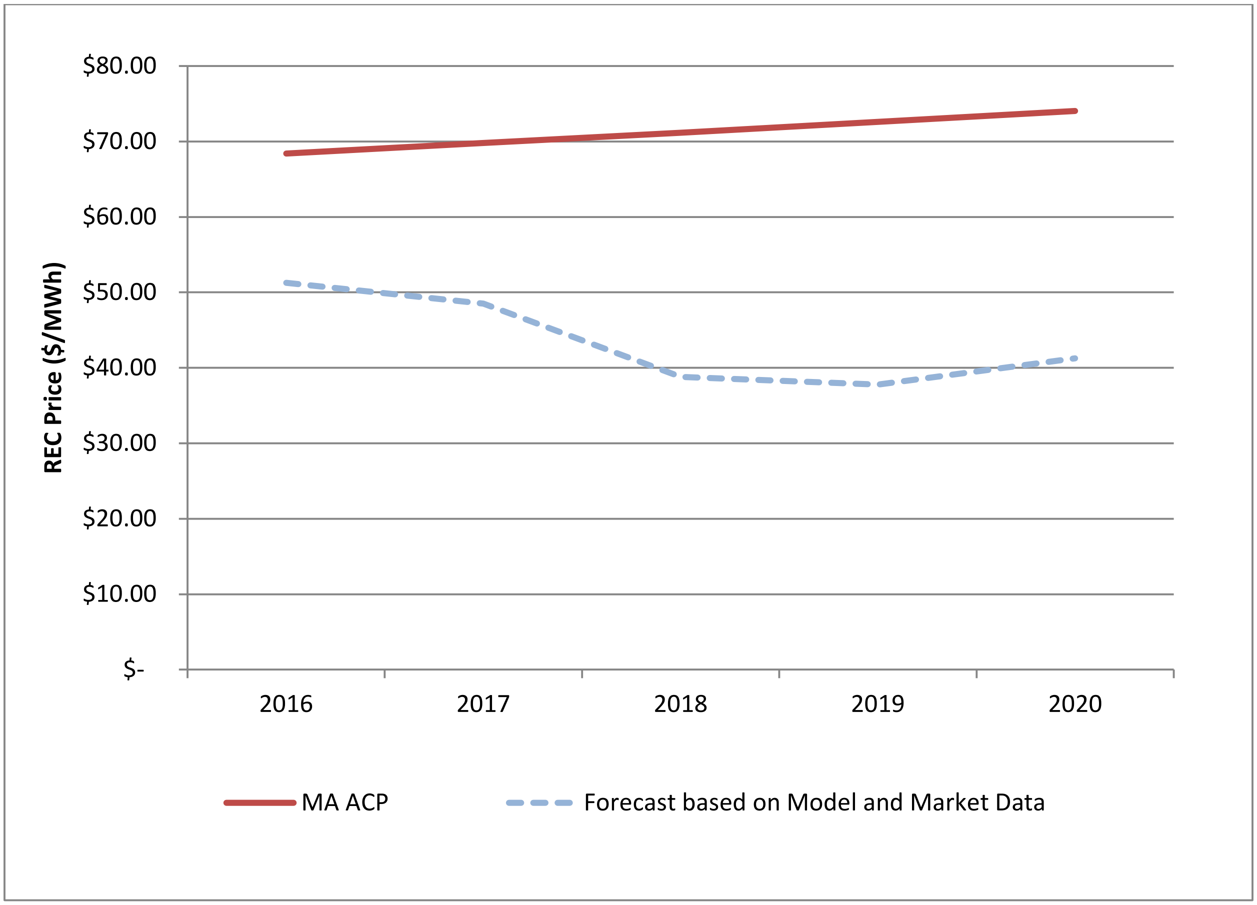
TABLE C-20. ANNUAL WIND BUILDOUT TO MEET RPS GOALS

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Megawatts (Nameplate) | 40 | 394 | 334 | 439 | 152 |

Alternative compliance payments ("ACP") provide a way for LSEs to meet their requirement levels without the purchase of RECs and were instituted to provide a cap on the cost exposure of LSEs during shortage conditions as shown in the figure. Use of ACP increases as conditions approach or are at shortage conditions. ACPs are generally set at a rate that increases with inflation. Thus, if wind resources are not built to meet the requirement, then ratepayers will pay a cost of the annual gap multiplied by the ACP in each year.

On the other hand, if wind resources are built to meet the RPS needs, then ratepayers should pay somewhat less than ACP, given the relatively high value set for the ACP (to discourage use of the ACP over purchasing renewable energy). This difference was calculated using a forecast of Class I REC prices created using La Capra Associates' proprietary supply/demand model. The figure below shows the gap between the prices that would be paid if supply was built to meet demand and the ACP level.

FIGURE C-27. ACP VS. PREMIUM REC PRICES




In order to calculate ratepayer impacts of continuing with the above supply-demand conditions, the price difference shown above by comparing the two curves in Figure C-27 multiplied by the amounts necessary to meet the demand levels shown in Figure C-26. Results of this calculation are shown in Table C-21 allocated to the four relevant customer groups.

TABLE C-21. RENEWABLE PORTFLIO STANDARD COSTS (CONSTRAINED – UNCONSTRAINED), MILLIONS OF 2014$

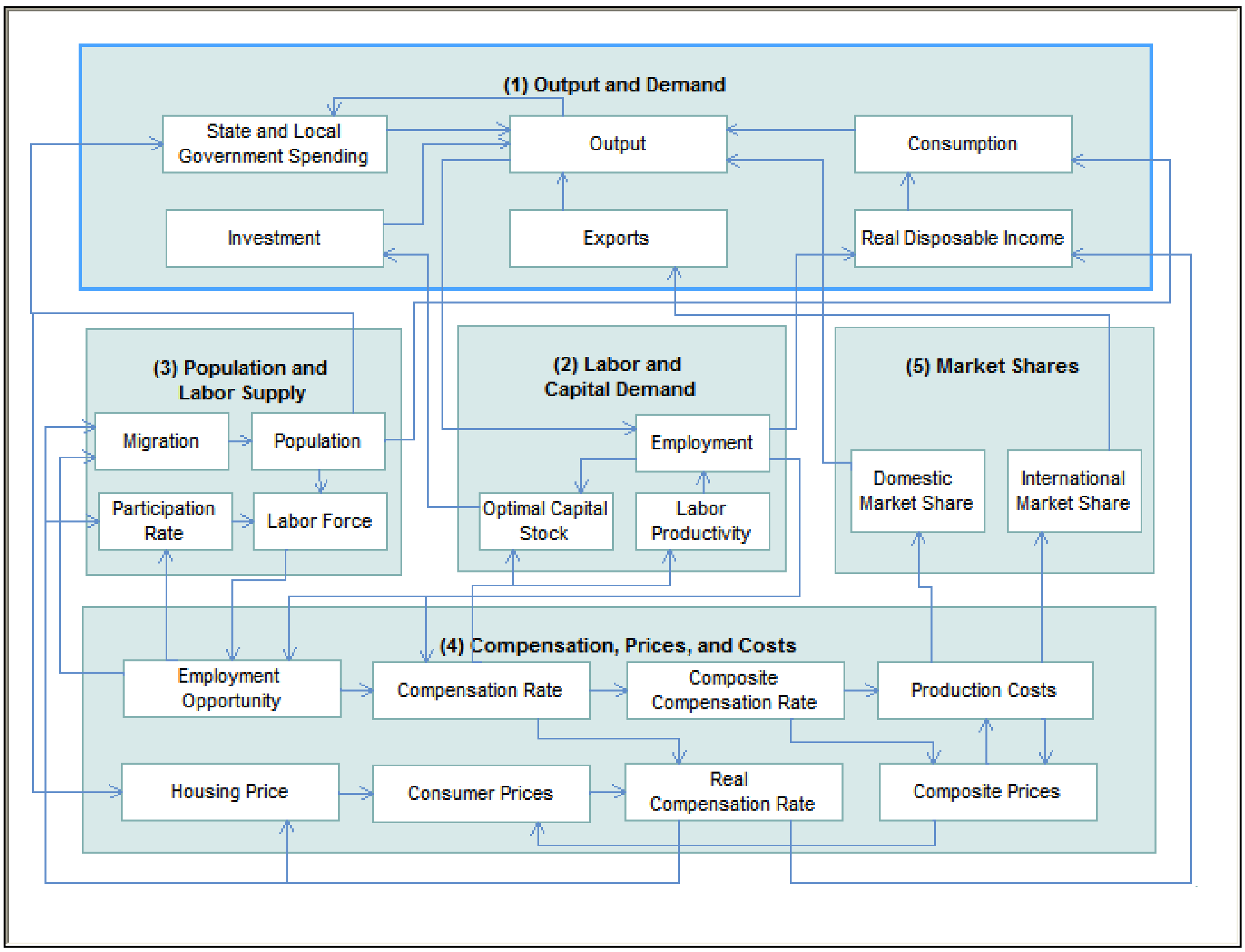
| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **Residential** | $0.65 | $6.64 | $17.26 | $26.39 | $25.42 |
| **Commercial** | $0.58 | $5.88 | $15.29 | $23.37 | $22.51 |
| **Industrial** | $0.32 | $3.26 | $8.48 | $12.96 | $12.49 |
| **Government** | $0.10 | $1.04 | $2.70 | $4.13 | $3.98 |
| **Total** | $1.66 | $16.82 | $43.73 | $66.85 | $64.40 |

A downward adjustment to the cost estimates was made due to impacts on revenues to renewable generators from the pipeline and transmission expansion. As discussed earlier, those infrastructure types are expected to exert downward pressure on LMPs, which is likely to be offset by increases in the cost of RECs. This increase in REC costs would tend to shift the lower curve shown in Figure C-27 upward and thus reduce the cost impact. Even with this adjustment, the cost impact of failing to build infrastructure is close to $200 million over the 2016-2020 period. Future years' impacts would be expected to be at least the amount shown in 2020 given the increase in requirements.

# APPENDIX D – ECONOMIC MODEL OVERVIEW

REMI's *PI+* software model was calibrated with historical data through 2013 for the New England economy (comprised of the six states in aggregate) and includes a year-by-year projection to 2060 on a large set of macro indicators as well as a set of indicators for each of 70-sectors. The rationale for using this model to complete the (higher) energy price investigation is that the cost structure facing New England's commercial and industrial customer-segments specifically has bearing on each sector's ability to compete (intra-regionally, inter-regionally, and internationally). Depending on the sector, an increase in the cost-of-doing business, brought on by persistent, higher energy costs, will erode competitiveness relative to *rest of U.S.* and *rest of world*. This translates into stalled market share (sales) hence lower employment. Because the REMI model is a dynamic, computable general equilibrium (CGE) forecasting system with ample structural equations to capture such elements, it can consider this cost shock that other systems (e.g. static input-output models) can not. And the model can readily depict "shocks" to the residential and public sector as well. Figure D-28 is a depiction of the model structure.

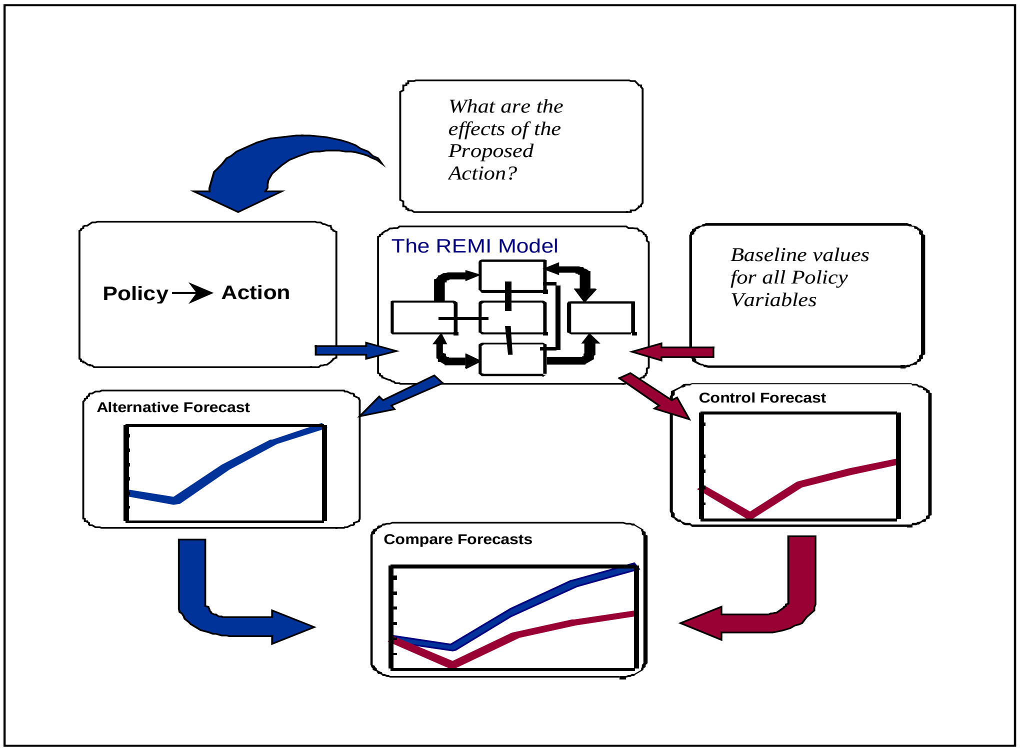
FIGURE D-28: THE REMI *PI*+ MODEL STRUCTURE




Source: Regional Economic Modeling, Inc., REMI documentation

The *impacts* of any scenario (or case) proposed to the REMI model are scripted by (a) the model solving an *alternative forecast* (in this instance, to 2020) once scenario information is introduced through a select set of policy levers into the software, and (b) comparing values for key metrics such as *private-sector employment* and dollars of *GRP*, in *year_t* against the control (or no shock) forecast. Figure D-29 portrays this process. In the graphic, the distance between the hypothetical blue line (alternative) and the red line (control) for one year (x-axis) is the measure of the impact (y-axis) in that year.

FIGURE D-29: IDENTIFYING ANNUAL IMPACTS IN THE REMI *PI*+ MODEL




Source: Regional Economic Modeling, Inc.