New England Overview

A Guide to Large-Scale Energy Infrastructure Issues in 2015

A Boston Green Ribbon Commission Report

Prepared by Dr. Jonathan Raab, Raab Associates, Ltd. and
Paul Peterson, Synapse Energy Economics, Inc.
on behalf of the Boston Green Ribbon Commission

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BOSTON Green Ribbon COMMISSION

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Synapse Energy Economics, Inc.

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Prepared for Boston's Green Ribbon Commission

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AUTHORS

Dr. Jonathan Raab, Raab Associates, Ltd.
Paul Peterson, Synapse Energy Economics, Inc.

118 South Street, Suite 3A
Boston, MA 02111

617.350.5544 | www.raabassociates.org

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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PURPOSE STATEMENT

The purpose of this guide is to help stakeholders in the City of Boston understand how regional electricity and gas infrastructure decisions are made in New England, and to introduce some of the the important infrastructure choices currently being discussed (debated) in the region.

The guide was prepared for the Boston Green Ribbon Commission, a network of business and civic leaders supporting the implementation of the City of Boston's Climate Action Plan (CAP). It is one of three information products commissioned by the GRC. The other two focus on: 1) a basic overview of how electricity prices are set in the Massachusetts market, and 2) an overview of options for large scale institutional renewable energy purchasing.[1]

The Boston Climate Action Plan has set aggressive goals for greenhouse gas (GHG) reductions for the City – 25% by 2020 and 80% by 2050. For the first four years of its operation (November 2010 – November 2014), the GRC's work in support of the climate mitigation goals of the City of Boston's Climate Action Plan (CAP) has focused primarily on energy demand issues – more specifically, reducing energy consumption and related greenhouse gas (GHG) emissions in the large building and institutional sector (also known as the Commercial/Industrial or C/I sector), and more recently, on reducing transportation-related emissions.

Electricity and natural gas demand is, however, only half of the energy system equation. The other half is energy supply – where the energy comes from (generation of electricity and extraction of natural gas) and how it gets delivered to customer end-use points (transmission, pipelines and distribution). It is clear that there are a number of important choices that stakeholders will be making over the next decade affecting energy supply and distribution. It is important for GRC stakeholders to understand the state's and region's energy supply situation, what the choices are, how they will affect their energy plans, and the ability of the City to achieve its Climate Action Plan goals.

The electricity and natural gas supply "ecosystem" in Boston, Massachusetts, and New England is complicated and dynamic, and involves a myriad of issues, initiatives, and regulatory decision-making processes and procedures. A complex mix of players is involved, including the Federal Energy Regulatory Commission (FERC), ISO New England, the Department of Public Utilities, regional electricity and natural gas utilities, and energy suppliers from outside the region. Decisions about energy infrastructure result in physical infrastructure that will last decades and have potential costs and benefits in the billions of dollars.

The Green Ribbon Commission requested this study because an overview of regional electricity and natural gas infrastructure issues would be useful to its members and the many other stakeholders

[1] All three of these reports are available for downloading from the "Materials" page on the Green Ribbon Commission web site.

impacted by these issues, but who are not already deeply involved in them. This guide is designed to serve that purpose.

Support for this guide is provided by the Boston-based Barr Foundation as part of its Climate Program and efforts to promote clean energy in the region.

1. INTRODUCTION

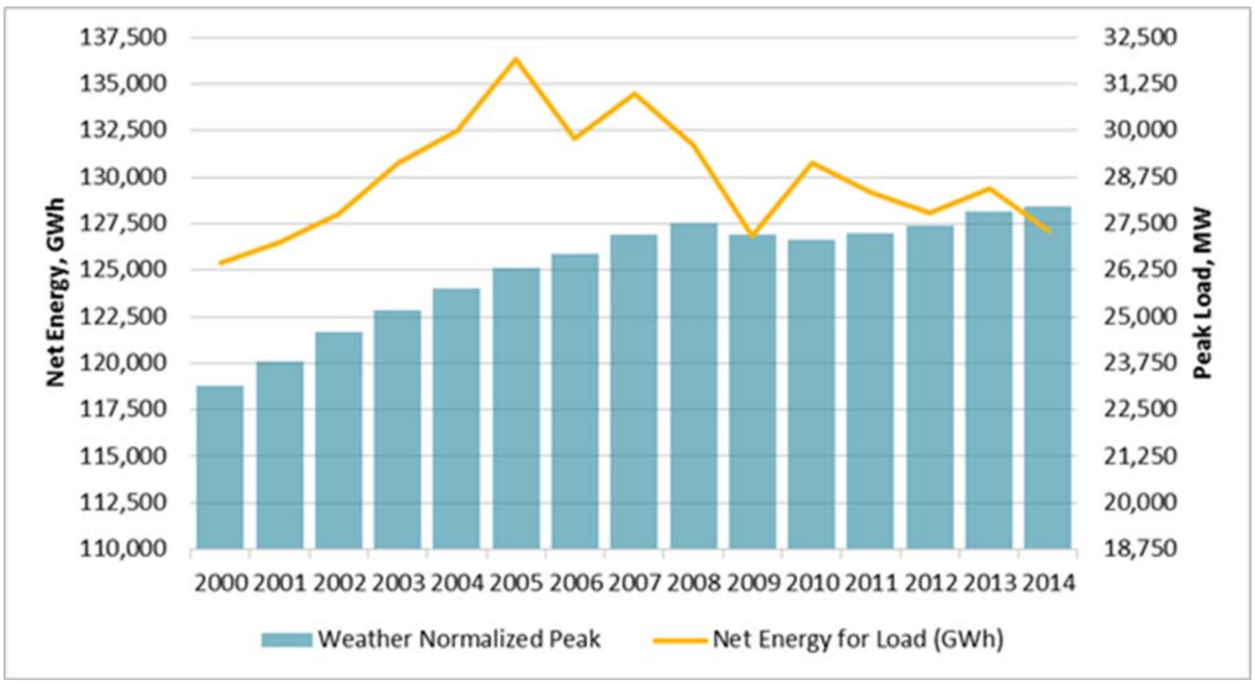
1.1. Historical Energy Trends

Stable Electric Consumption

Total annual electricity consumption in New England has not increased since its peak in 2005. In the past four years, a trend of annual declining consumption has begun, due largely to the region's aggressive pursuit of energy efficiency. Although summer peak loads are still increasing slightly year to year, the net rate of increase has slowed to less than 1% per year for the past several years. (See Figure 1.)

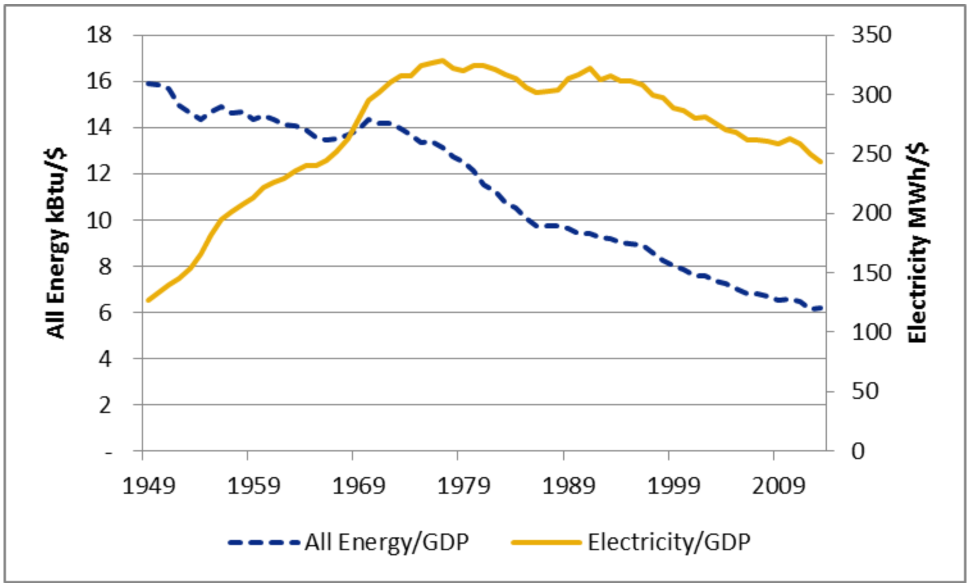
Also, New England is assumed to be similar to the U.S. as a whole, with declining energy and electricity intensity per unit of gross domestic product. (See Figure 2.)

Figure 1. New England historical annual energy and peak loads



Source: Synapse Energy Economics from ISO-NE CELT reports through 2014.

Figure 2. U.S. historical energy intensity

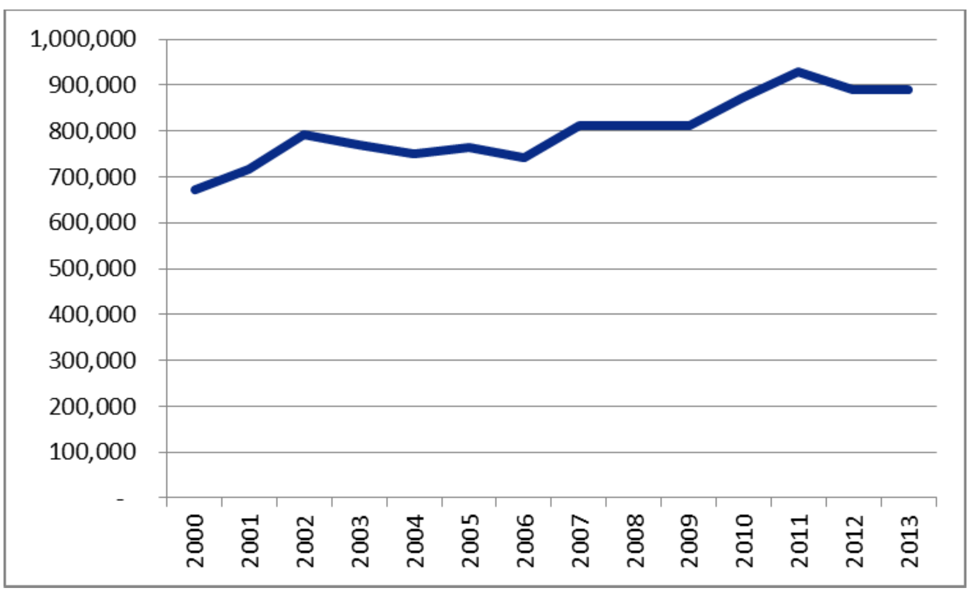


Source: Synapse 2015 graph from EIA, BEA, and USCB data.

Expansion of Natural Gas Consumption

In contrast to electricity, natural gas consumption has seen a slow but steady increase in New England over the past 15 years, from under 700 billions of cubic feet (Bcf)/year in 2000 to around 900 Bcf/year over the last few years.

Figure 3. New England gas consumption (MMcf)



Source: Developed by Raab Assciates using EIA Natural Gas Data

This has occurred due to the dramatic increase in gas-fired electric power plants over this period and a steady conversion to gas-fired home heating (displacing oil-fired heating) that has accelerated in the past few years. Even though long-term trends suggest steady improvements for the efficient use of energy, there are some near-term concerns regarding increasing reliance on a single fuel, natural gas; a fuel that is constrained during some of the times it is most needed (i.e., in the winter).

Winter Reliability

As gas-fired generation became more dominant in the last decade, ISO New England grew increasingly concerned about the adequacy of gas pipeline supplies during winter months. Gas distribution companies contract for pipeline supplies on a year-round basis, with the greatest demand for gas occurring in the winter months to meet heating needs. On extremely cold days, almost all current gas pipeline supply (and pipeline capacity) is needed for gas distribution customers, leaving most gas-fired generation plants unable to operate. On all days except extremely cold ones, gas distribution companies release (re-sell) their uncommitted gas supplies and the quantities are sufficient to support gas-fired generation for electricity. Even though gas-fired resources have capacity supply obligations (CSOs) to produce energy in the winter months, they routinely declare themselves unavailable due to lack of available gas. To address these concerns, ISO New England has developed both interim and long-term solutions that we discuss in greater detail in this section.

Next Steps

Some New England policy makers have focused on the need to expand transmission infrastructure to transport power from the North and to expand natural gas pipeline infrastructure into New England as solutions to electricity and gas price and reliability issues.

The rest of this paper examines the current infrastructure in New England and the numerous proposals, including new gas pipelines and electric transmission lines, that are being offered as solutions. We start with the electric system, next review the gas system, and then briefly discuss the major implications of both systems for Boston.

2. ELECTRICITY SYSTEM

2.1. Transmission Upgrade Approval, Cost Recovery, and Cost Allocation

Transmission facilities that are constructed to resolve reliability criteria violations are termed reliability upgrades and their costs are socialized to all customers through their utilities in New England. Transmission facilities that are constructed by private parties are merchant transmission facilities and they are evaluated by the ISO as an elective transmission upgrade (ETU). The costs to build and interconnect a merchant transmission facility are paid entirely by the private developer and ultimately collected from the purchasers of the electricity using the merchant transmission facility. If a merchant transmission facility is determined to also provide reliability benefits, the owners of the facility will be eligible to receive reliability credits, a form of additional compensation. For example, The Hydro Quebec (HQ) DC interconnections receive reliability credits while the Cross Sound Cable line to Long Island, NY, does not. The terms and conditions for reliability upgrades and economic upgrades are detailed in the ISO and transmission owners' tariff documents.[2]

Table 1 provides an overview of the different types of transmission system upgrades with a brief description of what drives the need for the upgrade and who builds the upgrade.

Table 1. Overview of transmission upgrades

Type of transmission upgrade	Driver of need	Who builds
Reliability	Based on the system needs assesment by ISO	Competitive
Merchant Transmission	Based on decision by a private party	Developer
Market efficiency	Based on a market-efficiency study by ISO	Competitive
Public policy	Based on a stakeholder ISO suggestion	Competitive
Backstop	If a competitive transmission provider fails milestones	Incumbent transmission operators
Generator interconnection	Needed to interconnect a new resource	Incumbent transmission operators

Synapse Energy Economics, April 2015

[2] ISO Open Access and Transmission Tariff (OATT), Attachment K and Attachment N.

To date, most upgrades have been driven by reliability needs with a few merchant transmission upgrades (none in the last ten years). There has never been a market efficiency upgrade nor, to date, a public policy upgrade or a backstop upgrade. Generation interconnection upgrades occur with regularity.

Generator upgrades are new transmission facilities, or modifications to existing facilities, that are necessary to allow a new generator to interconnect to the bulk power system. These upgrade costs to allow interconnection of new generators can range from relatively small costs to so large that the proposed new generator is priced out of the market; it all depends on the location of the new generator and the existing system conditions related to that location. Generator upgrades are paid by the generation owner.

Market efficiency upgrades are new facilities, or modifications to existing facilities, that reduce power delivery costs to a greater extent than the cost of the upgrade. Each year the ISO invites stakeholders to suggest economic studies and selects one or two to review and report back to the Planning Advisory Committee. State agencies, environmental groups, transmission companies, and specific resource developers (wind and solar) have all had economic studies done by the ISO. ISO New England can authorize a market efficiency upgrade based on a study showing net savings that exceed the costs of the new facilities. Although to date there has not been a market efficiency upgrade proposed or approved by ISO New England, the annual economic studies have provided useful information about where such upgrades could be considered.

Recently, ISO New England filed a proposal for a new Public Policy Upgrade option. A public policy transmission facility upgrade would address a public policy need and can have its own funding approach based on an agreement among states. FERC Order 1000 requires transmission providers to include a public policy option; as the New England transmission provider, ISO New England filed a proposal with the FERC that was supported by NESCOE and many other New England stakeholders.

As proposed, a Public Policy Project transmission facility upgrade would be designed to help implement a public policy, such as a renewable portfolio standard or to meet greenhouse gas goals. For example, a new transmission line could be constructed to allow for the delivery of wind resources from remote locations to a load center. The New England states could develop their own cost-allocation agreement and the ISO would review the proposal similar to a merchant transmission upgrade. If the states were unable to develop a cost-allocation agreement, a default cost-allocation mechanism would be implemented.

On March 19, 2015, the FERC issued an Order substantially approving the Public Policy Project upgrade proposal. The Commission reiterated its earlier comments that ISO New England, as the regional transmission provider, was the ultimate decision making entity on whether a Public Policy Project would be implemented. The New England States Committee On Electricity (NESCOE) or any other entity could propose a public policy project but the final decision resides with ISO-NE. The Order also confirmed the default cost-allocation mechanism where project beneficiaries pay for 30% of the cost and the remaining 70% is socialized to all New England load. Some stakeholder had proposed a 70% payment from the beneficiaries and the remaining 30% be socialized.In April, Connecticut, Rhode Island, and Massachusetts issued a draft RFP to share in the acquisition of renewable energy resources that could require new transmission to bring wind and hydro resources most likely from Northern New England and Eastern Canada to Southern New England. The wind and hydro resources would help the three sponsoring states meet their climate goals, and/or their Renewable Portfolio Standards. To the extent that transmission is involved, this could potentially go through the ISO New England planning process under the new Public Policy Project upgrade procedures.

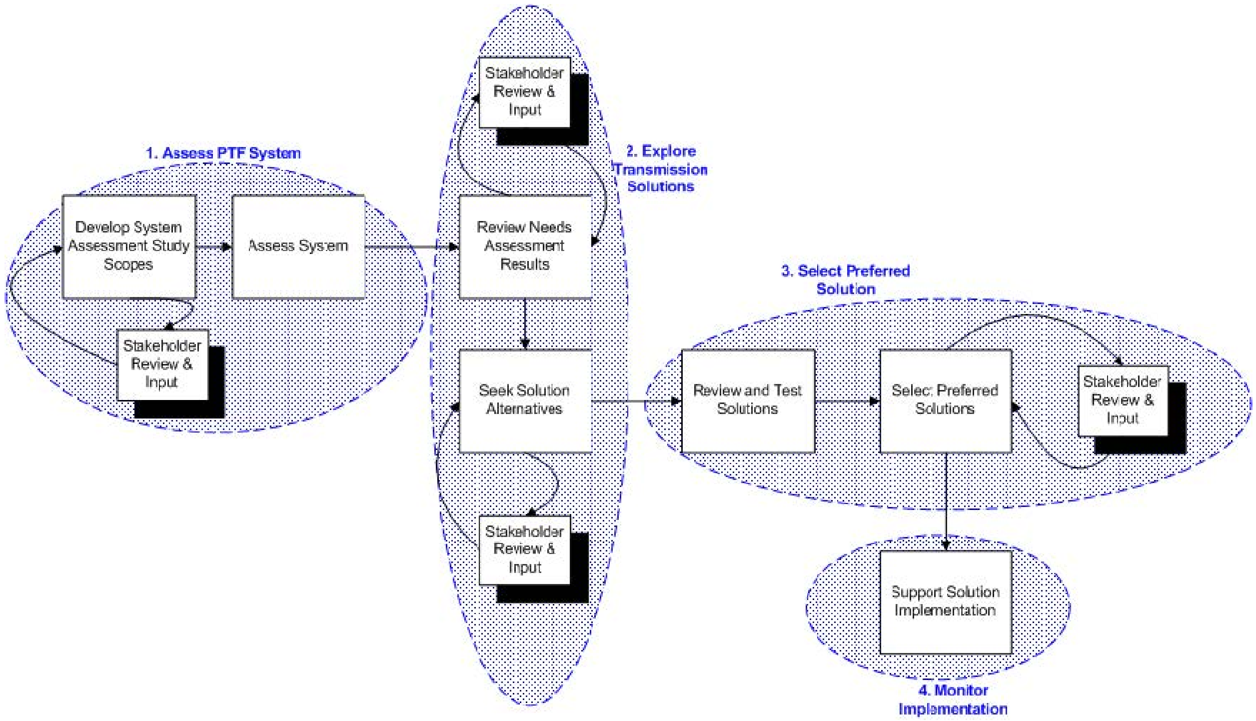
Developing and Approving Transmission Upgrades

The FERC has delegated authority to ISO New England to periodically assess the regional power system to resolve both existing and future violations of reliability criteria pursuant to FERC-approved tariff language. Attachment K to the ISO open access transmission tariff (OATT) describes the process that the ISO will follow when doing its assessments of needed upgrades and the solutions that are selected. The Commission's approval of a transmission upgrade occurs at the end of the process, after the upgrade is completed and in service, when the FERC must determine the allowable costs of the project, plus a return on investment, that will be included in wholesale rates. Most transmission upgrades provide long term benefits that result in 10-20 year (or longer) recovery periods. The Commission relies on ISO-NE (the planning authority) to approve the construction of transmission upgrades, including a determination that the costs to construct the upgrade are appropriate.

Figure 4 shows the process for a reliability upgrade. First the ISO evaluates the existing system conditions over the next ten years to determine if there are likely to be any violations of reliability criteria. Reliability criteria that are evaluated include thermal limits, voltage, and short-circuit issues under stressed system conditions (high and low loads) across all seasons. All transmission lines have maximum capacities that are expressed as thermal limits. The ISO tests the system under multiple combinations of resources and loads to see if any thermal limit violations occur. Voltage must remain within prescribed frequencies so the ISO also tests multiple resource and load conditions to see if any voltage limits are exceeded (high or low). Finally, the ISO evaluates the likelihood of short-circuits occurring under multiple conditions of resource combinations and load levels. If any of these tests (sometimes thousands of different combinations) show that a reliability standard has been violated, the ISO may conduct additional tests to determine the exact extent of the problem. Reliability criteria violations require correction so the ISO will evaluate solutions for each violation that occurs.

The specific steps that the ISO takes are detailed in two documents: the Process Guide and the Technical Guide. These documents are updated periodically to incorporate FERC orders and North American Electric Reliability Corporation (NERC) guidelines. If reliability violations are found then the ISO announces that there is a need for a solution. If a market-based or non-transmission solution is proposed (new generator(s) for example), the ISO will evaluate whether that solution will resolve the reliability criteria violations. If no alternative solutions are proposed or sufficient, the ISO will look for a transmission solution.

Figure 4. ISO-NE planning process



Source: ISO New England PAC presentation February 24, 2010.

The development of transmission solutions is done in a study group that includes the ISO and the incumbent transmission owner in whose service territory the reliability violations are projected to occur. Prior to FERC Order 1000, the solution or multiple solutions proposed by the study group would be shared with the Planning Advisory Committee and evaluated by ISO New England. Order 1000 requires more transparency and the Commission recently confirmed that the study group needs to be open to stakeholders.[3] In addition, Order 1000 requires that ISO New England must allow competitive solutions from other transmission providers to offer alternatives and evaluate those alternatives; prior to Order 1000, transmission owners had a right of first refusal for any transmission upgrades in their service territory. Even with the competitive process, the incumbent transmission provider can develop a backstop solution to address the reliability violations in case the competitively selected transmsission builder fails to meet milestones. For solutions that are needed in three years or less, ISO New England does not have to go through a competitive process due to time constraints.[4]

Once a preferred solution is selected by ISO-NE, the transmission provider (builder) begins the state approval process before a state siting commission or public utility commission (or multiple-state reviews

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[3] FERC Docket No. ER13-193, March 19, 2015.r

[4] ISO-NE had proposed a five-year horizon for competitive alternatives but the Commission reduced that horizon to three years. March 19, 2015 Order

for some projects). In Massachusetts it is the Energy Facilities Siting Board (EFSB) that reviews proposed plans for large transmission projects[5], holds hearings, and imposes conditions or modifications to the transmission provider's proposed solution. States' reviews can include an examination of whether the transmission line is needed, and can look at alternative routes (EFSB review generally includes costs, environmental impacts and design considerations, e.g., whether portions should be undergrounded) and alternative resources (such as non-transmission alternatives). State reviews typically take around a year for a major transmission line, and approval decisions typically include dozens of conditions that a developer needs to comply with. (For a more in-depth explanation of Massachusetts Energy Facility Siting Board and its procedures, see Appendix C). Note that this is in stark contrast to the siting of interstate pipelines, where the Federal Energy Regulatory Commission (FERC) and not the states essentially approves the siting of the pipeline and issues the construction permits (See gas approval process section below).

Some conditions and modifications that States impose can be substantial enough to require further review by ISO-NE[6] and might make previously rejected solutions more attractive. This can typically occur when a state board requires undergrounding of transmission lines (for safety or aesthetic reasons) or requires significant remediation efforts for using public lands. The transmission provider may seek an alternate route or re-design the upgrade to avoid substantial cost increases.

Cost allocation for electricity projects

Table 2 shows the normal cost recovery treatment for various upgrades based on the language in the ISO tariff. We discuss them in more detail below.

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[5] The EFSB has jurisdiction regarding: (1) new electric transmission lines having a design rating of 69 kilovolts or more and which are one mile or more in length on a new transmission corridor; and (2) new electric transmission lines having a design rating of 115 kilovolts or more which are 10 miles or more in length on an existing transmission corridor except reconductoring or rebuilding of transmission lines at the same voltage. Other transmission projects falling short of EFSB jurisdictional thresholds may be subject to review by the Massachusetts DPU under its Section 72 authority.

[6] However, ISO would not re-evaluate its preferred solution based on state-level reviews by Siting authorities. If state-imposed decisions require selecting an alternative design, mitigation measure, or another route, ISO would evaluate whether the additional costs conform to "good engineering practice." Any incremental costs above those required by "Good Engineering Practice" (resulting from state-level requirements) are allocated to the local utility (customers within that affected state) rather than to all New England customers.

Table 2. New England cost allocations for upgrades

Upgrade Type	Cost Allocation
Reliability	All New England loads based on peak load ratio share
Merchant Transmission	Paid by transmission builder
Market Efficiency	Paid by beneficiaries
Public Policy	By agreement; or default (30% beneficiaries, 70% all New England load)
Generator Interconnection	Paid by generator
Market Resource Alternatives (Generation, EE, DG, Other)	Paid by beneficiaries or paid by local (i.e., state)

Source: Synapse Energy Economics, April 2015.

After all reviews are completed by state agencies and ISO-NE, the transmission provider starts construction. When the upgrade is complete and in service, the transmission provider will ask ISO New England to make a Transmission Cost Allocation (TCA) determination of the project costs. The transmission provider then includes the ISO-approved costs in its annual petition to the FERC for recovery of all of its transmission facilities' costs through a FERC-approved formula rate. The formula rate covers both reliability costs through the Regional Network Service (RNS) rate and local costs through the Local Network Service (LNS) rate. Anyone who seeks to challenge any of those costs must do so by filing a complaint with the FERC and presenting evidence of inappropriate costs.

The RNS rate is paid by all New England loads on a pro-rata basis determined by historical coincident peak loads. For example, if a new $100 million transmission facility was constructed that resolved reliability issues on the New England grid, the utilities in each state in New England would be assessed a portion of the total cost based on each utility's contribution to the system peak in the previous summer. Table 3 on page 18 shows the current load-ratio-share values for the New England states. These values are updated annually and they are applied at the time that a transmission facility is completed and goes into service. Costs are collected based on the terms of a tariff approved by the FERC; these tariffs will amortize the total costs over a period of twenty to thirty years with appropriate carrying costs included. Although the state percentages remain relatively stable over time, the financial significance of even small changes on the load-ratio-share results in these values being closely scrutinized by FERC.

The LNS rate is paid by the customers of each distribution utility and they are included in a separate formula in the same transmission owner FERC filing that recovers the RNS costs. Distribution facilities are at lower voltage than the bulk power system, usually 34.5 kV or lower. However, the FERC employs a seven-part technical analysis based on the functions performed to definitively determine if all, or a portion, of a particular line or facility is considered a "transmission" asset or a "distribution" asset. This occurs most often with substation facilities where some of the facility is supporting the transmission function (RNS rate) and some of the facility is supporting the distribution function (LNS rate).

The New England history of socializing Regional Network Service costs evolved over numerous years following the interconnection of the New England grid after the 1965 Northeast blackout. Once reliable electric service became a true regional issue, the logic and economics for sharing regional costs became persuasive. One of the important roles that ISO-NE performs is the analysis of project costs that are eligible for regional socialized treatment. As an example, ISO-NE will review the design of a transmission line to make sure that it meets electrical standards, but deny cost recovery through the RNS rate for add- on elements or frills. If a portion of a line needs to be underground based on standard utility practice (too close to structures for safety reasons) that can be recovered through the RNS rate; however, if the line is underground due to aesthetic concerns of abutting neighbors, that will be considered a local cost and recovered through the LNS rate.

The distinction between RNS and LNS rates for cost recovery is of particular importance when discussing non-transmission alternatives. ISO-NE uses the term “market resource alternatives (MRAs)” to identify solutions to reliability criteria violations that are not transmission solutions: they can be generation projects, energy efficiency programs, demand response, small-scale distributed generation, energy storage or combinations of these options. ISO-NE began doing MRA studies in 2011 and continues to include MRA studies as part of its needs assessment process. To date, there have been three MRA studies: one for VT-NH needs assessment; one for the Greater Hartford Central CT needs assessment; and one for the SEMA/RI needs assessment. In these studies, the ISO identifies the approximate quantity and location of generation that could avoid the need for a transmission upgrade. Generation injections are roughly equivalent to load reductions in transmission planning so the generation values also serve as proxies for EE and behind the meter resources (rooftop PV, combined heat and power, backup generation, or combinations).

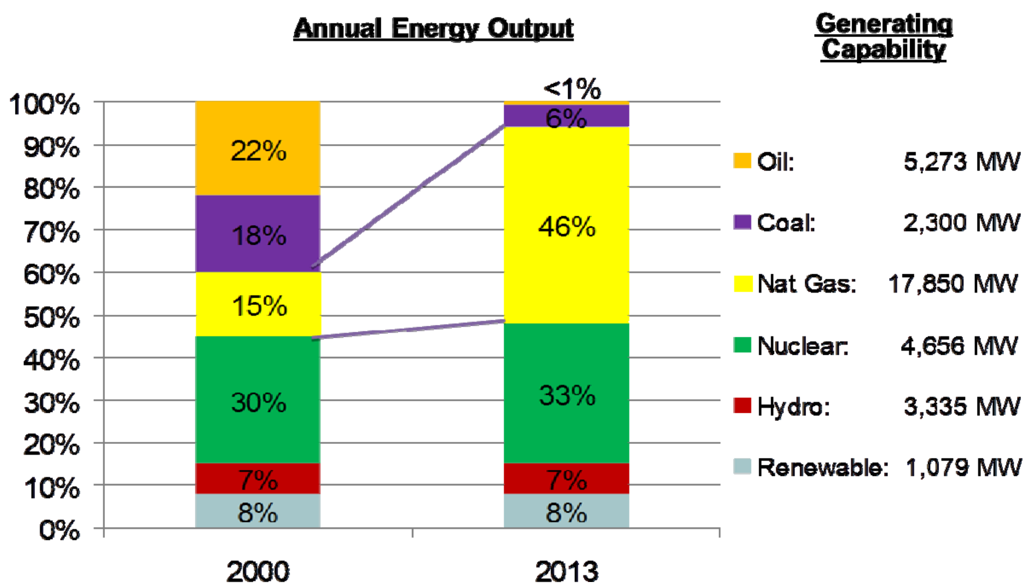
The challenge for those proposing MRAs instead of a transmission upgrade is the cost allocation for the two options. MRAs are considered local costs and paid entirely by the utility (or state) that implements them. The transmission upgrade, as noted above, is paid by all the utilities (states) in New England. For example, a $100 million transmission upgrade would cost Maine about $7.5 million (its peak load ratio share) with the balance paid by the rest of New England. A less societally costly MRA solution, say $70 million, would be entirely paid by Maine if the MRAs were located in Maine. Given the cost allocation disparity, Maine would pay an additional $62.5 million for the MRA solution even though it costs $30 million less from a societal perspective. The scales are tipped in favor of Reliability Transmission Upgrades over other options that may not require significant transmission system changes. However there may be a new option available through the recently approved Public Policy Upgrade option. As approved by the FERC, states may elect a cost-sharing method for a transmission upgrade that support public policy goals. A non-transmission alternative (essentially an MRA) could be socialized among the states if they agreed to do so, thus (at least in theory) providing closer to a level playing field for both the transmission solusiton and the non-transmission solution.

2.2. Electricity Infrastructure

Generation

Figure 5 below shows the transition of the New England generation fleet over the last decade, underscoring the significant increase in gas-fired generation and a corresponding decline in coal and oil generation. ISO New England anticipates meeting 50% or more of the regions energy needs with gas-fired generation in the next year or two. The retirement of Vermont Yankee (nuclear 600 MW) in December 2014 and the 2017 retirement of Brayton Point (coal 1100 MW; oil 400 MW) are not reflected in the 2013 capacity data—meaning the reliance on natural gas for fuel generation will increase further over the near term.

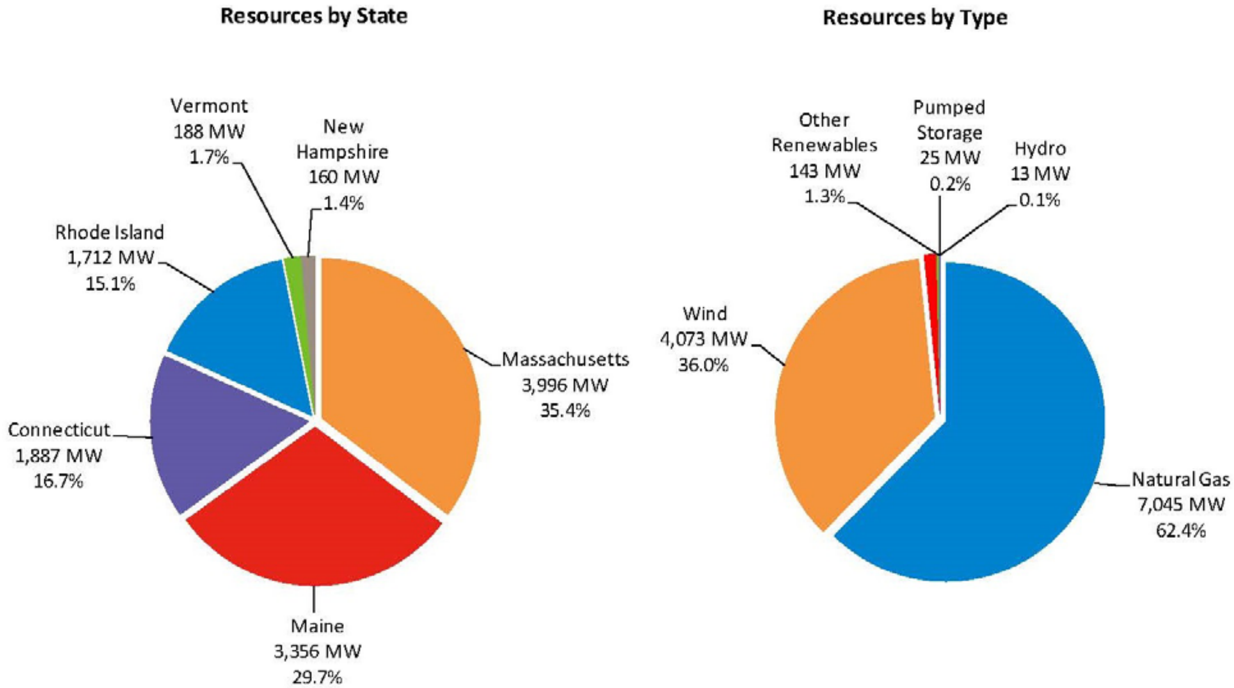
Figure 5. Generation resources



Source: MA Roundtable, November 21, 2014.

New resources being studied in the ISO interconnection queue are almost entirely gas and wind resources. Figure 6 shows the current mix of resources in the ISO study queue. Wind and natural gas resources combined are 98% of the new resources. The "Other Renewables" category (1.3%) includes photovoltaic, landfill gas, biomass, refuse, and fuel cell resources. Within the natural gas category, 4,772 MW (68%) are specified as dual-fuel (gas and oil). The total of over 11,000 MW of new resources in the interconnection queue in March 2015 shows a significant increase over the quantities in 2014 (6,000 MW) and 2013 (5,000 MW).

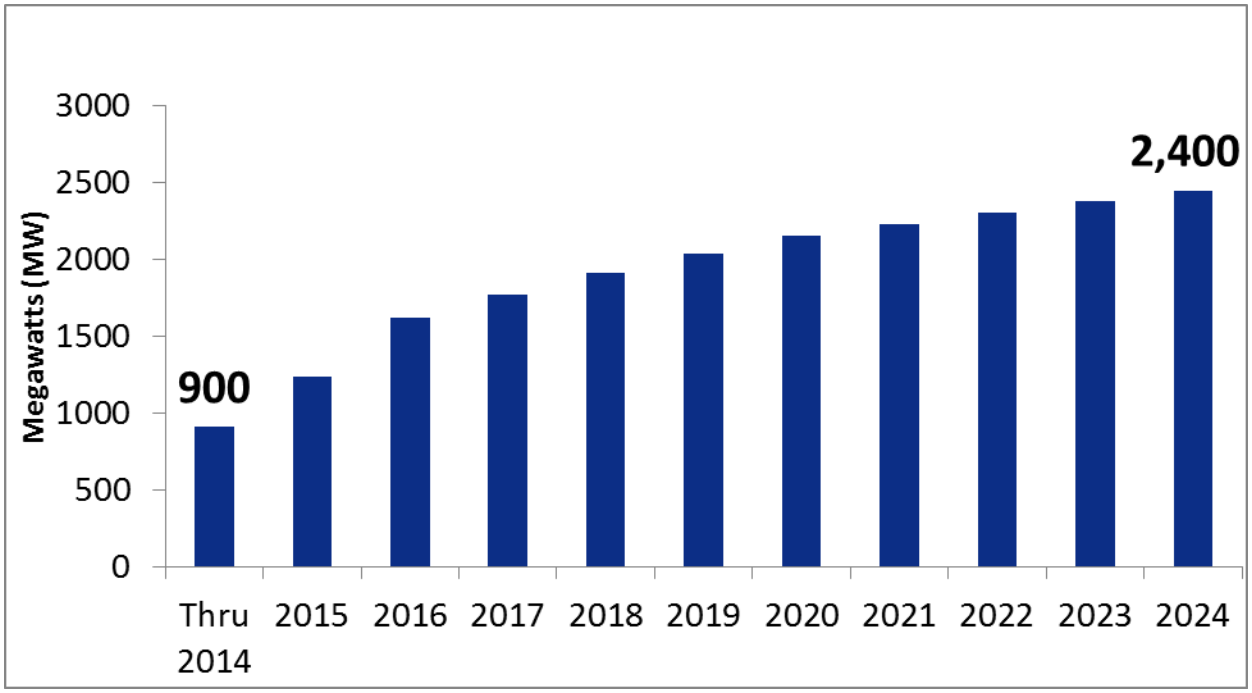
Figure 6. Resources in the ISO generator interconnection queue by state and fuel typer (MW & %)



Source: ISO-NE Planning Advisory Committee presentation, April 28, 2015.

Additional new resources include solar PV. Some of these installations are similar to other generation resources but most are behind-the-meter resources (largely rooftop solar) that appear to the ISO as reductions to load and are not part of iSO's interconnection queue. The ISO's 2015 solar PV forecast process has documented a rapid increase in solar PV from about 100 MW in 2010 to over 1,000 MW in 2015, and over 2,400 MW projected by 2024, as shown in Figure 7.

Figure 7. Cumulative growth in solar PV through 2024



Source: ISO-NE Roundtable presentation April 17, 2015.

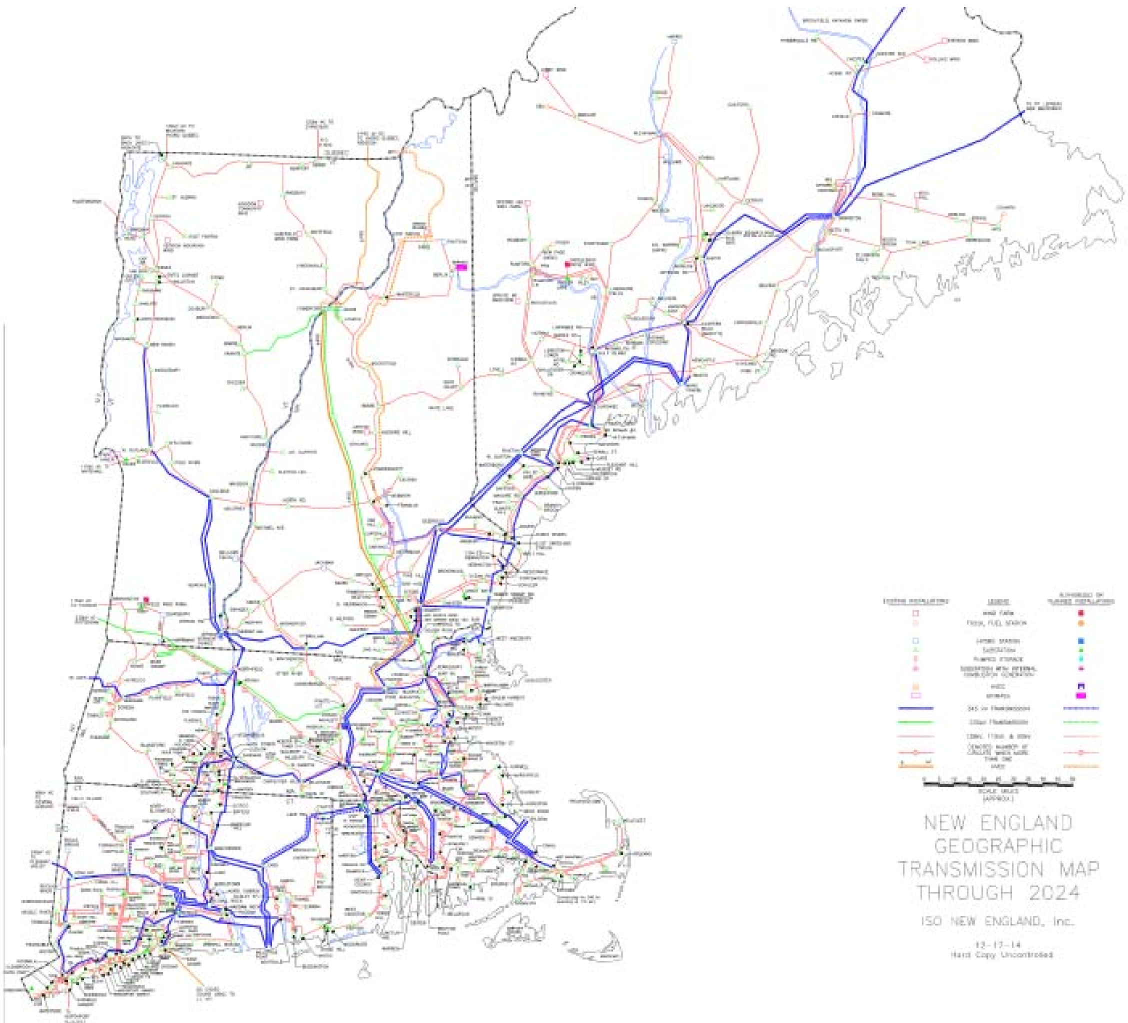
Transmission

The New England regional grid is comprised of all six New England states and connections to neighboring regional grids of New York and Canadian provinces. As with other power grids, the New England grid is inter-dependent. When a demand or load is placed on the system, a supply resource must be turned on to balance the load. This balancing of loads with resources occurs 24-hours a day, every day of the year. Small imbalances are corrected on a moment to moment basis through resources that have automated generation controls that can be adjusted by ISO New England, up or down, in 5-minute intervals or less. Other resources follow hourly and inter-hour dispatch instructions from ISO New England that specify when resources need to ramp up or ramp down. For imbalances that are forecast in advance (such as predictable morning and evening ramp periods), ISO New England will ask resources to start operation or turn-off based on a day-ahead schedule that can be re-adjusted in real time as necessary.

New England has a back-bone 345 kilovolt (kV) transmission system that is supported by numerous smaller 115 kV lines and some lines of even lower voltage (69 kV and 34.5 kV). In total, over 8,000 mile of transmission lines crisscross the New England region. The bigger the line, the more efficiently it can move electricity form one destination to another. Most large generation plants feed into the 345 kV systems but there are also numerous generators that connect to 115 kV and smaller transmission lines. See Figure 8 for a map of existing transmission lines in New England.

Tens of thousands of miles of distribution lines from substations then deliver the electricity to end use customers. Substations convert the electricity from the higher voltage transmission lines to the lower voltage distribution lines (34.5 kV or smaller). The distribution lines have transformers that lower the voltage even further before it is actually delivered. There are some small generators including an increasing amount of distributed generation (including 1,000 MW of solar photovoltaics) that feed into the smaller elements of the overall transmission and distribution system.

Figure 8. New England grid internal



Source: ISO New England website.

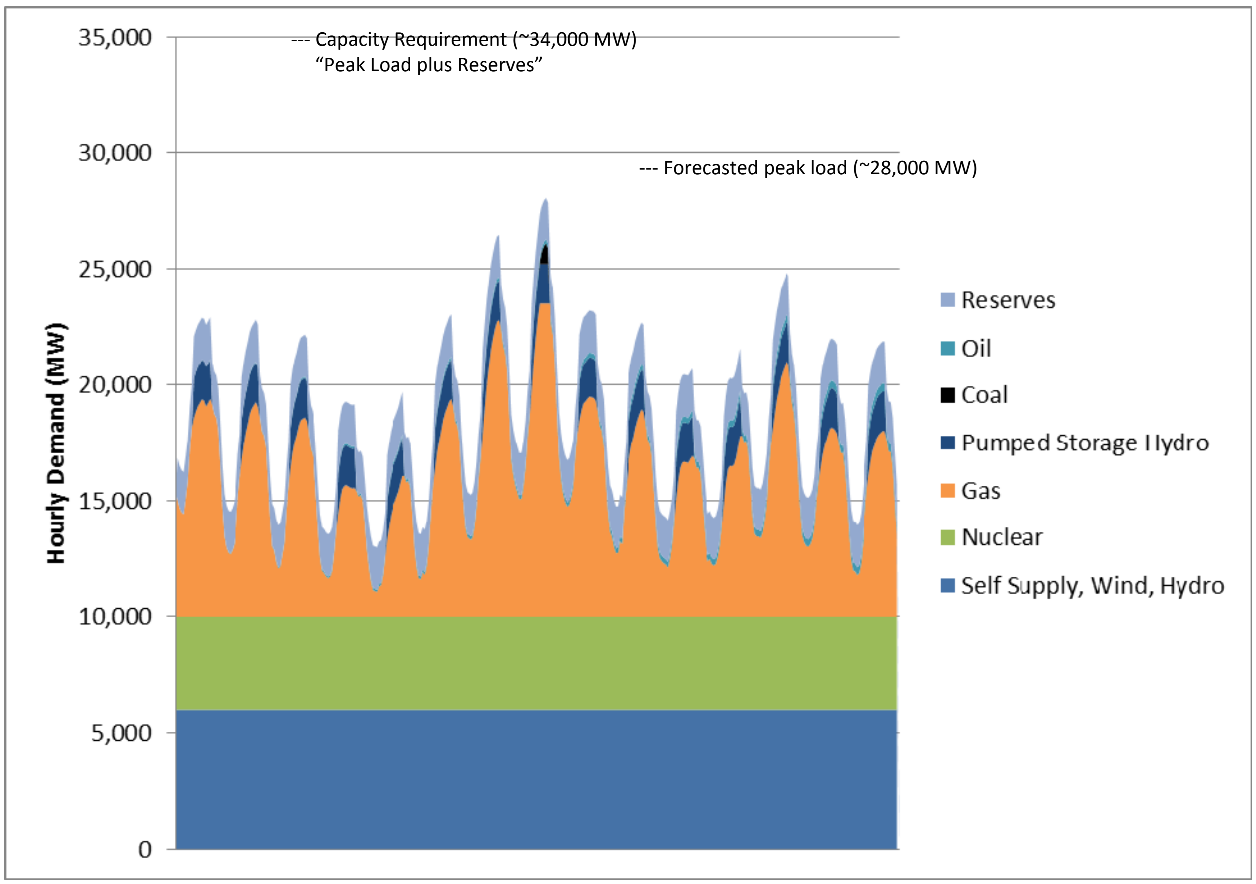
There are some transmission facilities that were not built primarily to resolve reliability constraints, but for economic benefit. Most notable is the DC line from Hydro Quebec across the Canadian border through New Hampshire to Northern Massachusetts that can provide up to 2,000 MW of electricity (mainly Canadian hydro). There is also a small, 200 MW DC line that connects from Canada into VT, and a 200 MW cable from CT to Long Island. These were all merchant transmission projects that were paid by their developers (aka sponsors); costs were not shared on a load-ratio basis among all New England utilities and their customers. Instead, the owners of the projects collect revenues for the use of the transmission line by those selling the electricity to customers.

Loads

The third component of the electric system is the loads of the consumers of electricity. These loads have a general variability depending on the time of day, day of the week, and the season. The two-week illustrative example of summer loads in Figure 9 shows the daily variation from (peak daytime peak versus nighttime valley); the overall lower loads on Saturday and Sunday; and the variation between hotter versus cooler summer days (largely due to changes in air conditioner use).

The graphic also illustrates the resources that would supply electricity at every hour during that particular two-week period. The bottom tier (blue color) are resources that schedule themselves on, regardless of price (self-supply resources), and resources that operate intermittently whenever their fuels are available (wind and water resources). The green are the nuclear baseload units that are mainly always running, and the rest are a range of load following resources, including natural gas, that are ramped up and down to meet load.

Figure 9. Supply and demand for two summer weeks



Source: Synapse, Doug Hurley Feb 2015.

Addressing load variability (whether seasonal, minute-to-minute, or an interval in between) is the greatest challenge to ISO operations. Reliable delivery of electric service is the first and the most important responsibility of ISO New England. It permeates and controls the culture of the institution and it has ripple effects in the ISO's execution of its planning and market responsibilities.

In 2014, as Table 2 illustrates, New England consumed 118,974 million KWHs. Forty-five percent was consumed in Massachusetts, 25% in Connecticut, and the remaining 30% in Maine, New Hampshire, Rhode Island, and Vermont combined. The commercial sector was the largest consuming sector (44%), followed by the residential sector (40%), and then the industrial sector (15%). The transportation sector consumed less than 1% of all the electricity in New England.

Table 3. 2014 retail sales/consumption of electricity in New England (millions KWHs)

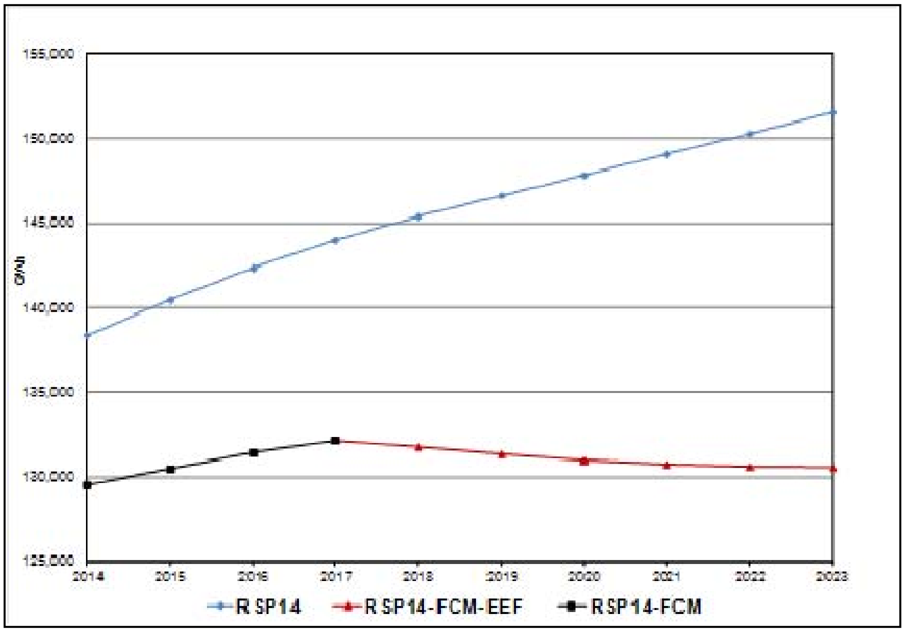
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	New England	Percent by End Use
Residential	12,837	4,657	20,025	4522	3,070	2114	47,225	39.7%
Commercial	12,941	3,986	25,737	4490	3,658	2038	52,850	44.4%
Industrial	3,398	3,348	7,358	1964	887	1394	18,349	15.4%
Transportation	183	-	367				550	0.5%
Total All sectors	29,359	11,991	53,487	10,976	7,615	5,546	118,974	100.0%
Percent by State	24.7%	10.1%	45.0%	9.2%	6.4%	4.7%	100.0%	

Source:Developed by Raab Associates using EIA Electricity Data.

ISO New England load forecasts are revised each year and published in the Capacity, Energy, Load, and Transmission (CELT) Report available around May 1. Since 2010, the ISO has incorporated a separate energy efficiency (EE) forecast into the annual CELT Report that has the effect of reducing future energy and peak loads in a substantial manner. The EE forecast represents the impact of existing and planned EE programs that are administered by a variety of utility and non-utility entities across the New England system.

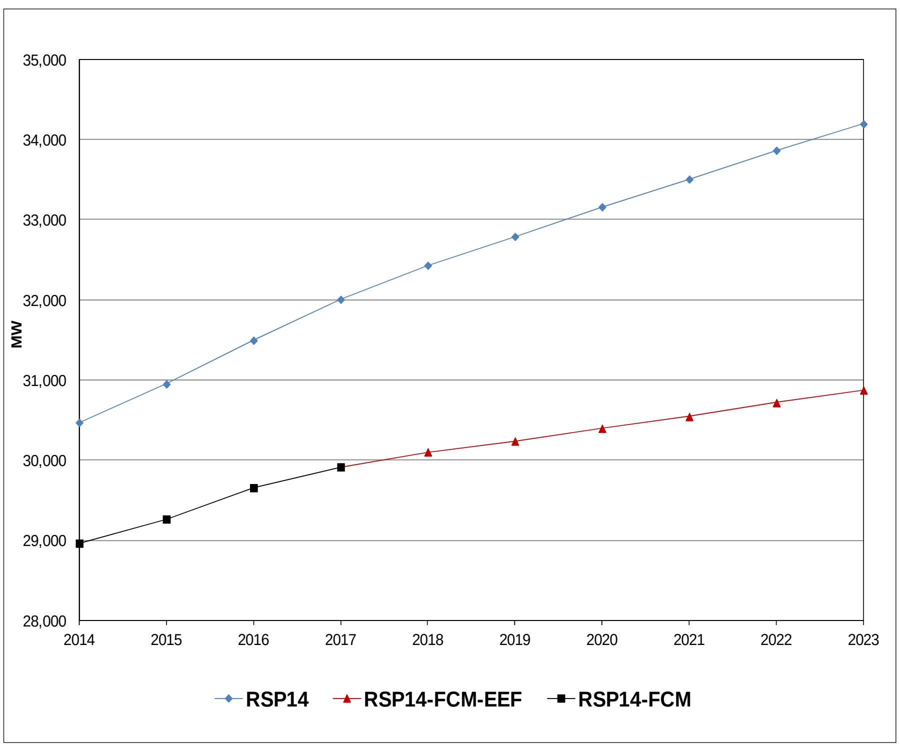
In Figure 10 and Figure 11 below, both the energy forecast and the peak load forecast show a significant reduction over time from the traditional load forecast (RSP14) developed by the ISO in both energy (GWH) and capacity (GW) due to the region's aggressive energy efficiency (EE) programs.

Figure 10. 2014 RSP forecasts for energy (GWH)



Source: ISO New England 2014 Regional System Plan.

Figure 11. 2014 RSP forecasts for peak load (MW)



Source: ISO New England 2014 Regional System Plan.

EE resources have a greater impact on the annual energy forecast than on the peak load forecast because EE measures are more focused on improved energy efficiency across all hours of use, not just peak hours. For example, residential lighting has only a small impact on summer peak loads that normally occur during summer afternoons; whereas commercial lighting in buildings has a large impact on those same summer peak loads. On a long-term basis, we may be continuing a trend to stable or even declining annual energy consumption as shown by the historical record in Figure 12 (below).

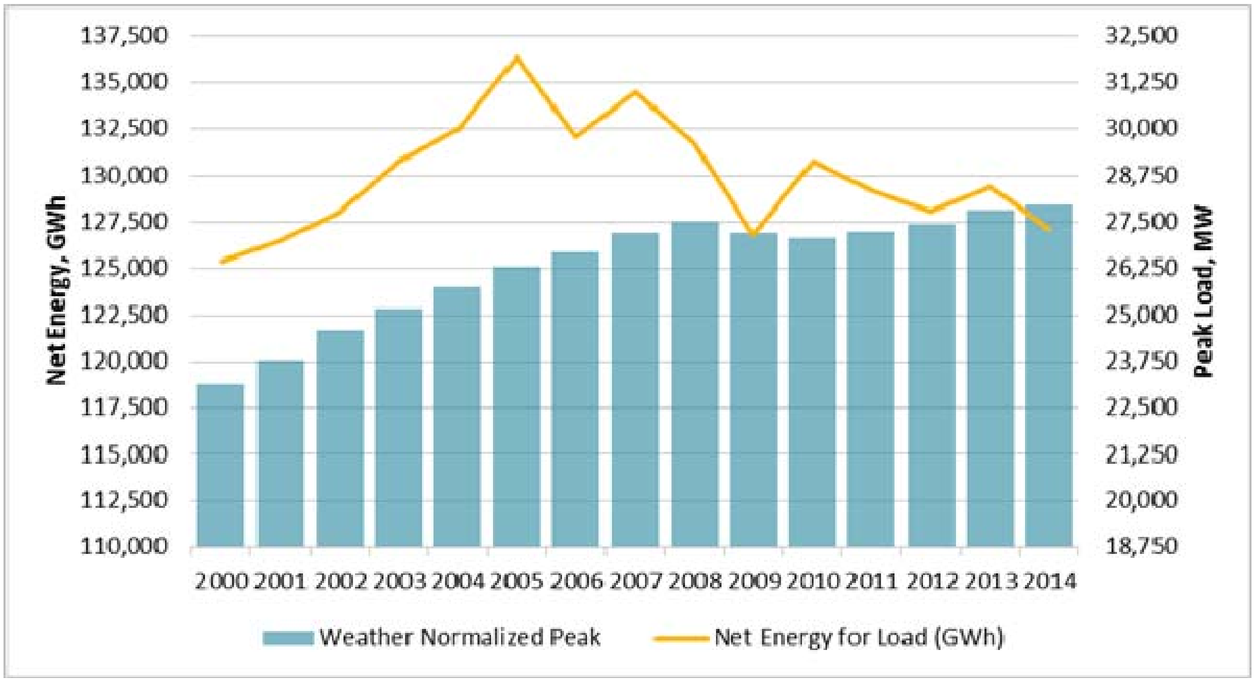
2.3. Electric system issues/challenges

There are three specific challenges that can have a large impact on both short-term and long-term costs for providing reliable electric service.

Adjusting to Reduced Consumption

Reduced electricity growth rates and the potential for year-over-year reductions in energy consumption from the grid present challenges to the utility business models in New England. New England historical trends in annual energy consumption and peak loads show even greater reductions than those occurring in other regions of the United States. Annual energy consumption, when adjusted for weather and energy efficiency measures, shows almost no growth since 2006 and a consistent decline since 2009. Peak loads are still growing, but at ever slower rates. Given the continued implementation of energy efficiency programs and rapidly growing solar PV installations (from less than 100 MW in 2010 to over 1,000 MW in 2015 and ISO New England projection of 2,400 MW by 2024), weather normalized peak loads may start to decline year over year and annual energy consumption may start declining at a faster rate. The only foreseeable potential counter-veiling force could be a rapid growth in the electrification of our cars and other motor vehicles, and conversion of gas and oil space heating to electric heat using high-efficiency heat pumps.

Figure 12. New England historical annual energy and peak loads



Source: Synapse Energy Economics from ISO-NE CELT reports through 2014.

Adjusting to Winter Risks

Despite overall declining electricity consumption, natural gas consumption in New England has shown steady annual increases due to expansion of gas for space heating needs and the construction of new gas-fired resources to generate electricity. To address short-term concerns about the reliable operation of the bulk power system in the winter months, when gas supplies are most strained, ISO New England developed a three-month Winter reliability Program for the winter of 2013-2014.The program encouraged gas generators that were capable of burning oil to fill their oil tanks (and arrange re-supply as necessary) to ensure that the resource would be able to generate electricity even if gas supplies were short.[7] If the oil was burned to generate electricity, the generator would be compensated through the energy market; if the oil was not burned during the winter months, the ISO would pay the generator a pre-determined price for the unused oil. On days when gas supplies were adequate, the oil would not be burned because gas cost less than oil per megawatt produced. Although New England experienced severe price spikes during the polar vortex events when gas supplies were limited across the northeast, the reliability of electric service was maintained through the availability of over 3 million barrels of oil. The total program cost, for unburned oil left in storage tanks after the end of February, was less than $70 million.

[7] A small quantity of demand response resources were also eligible for compensation under the winter reliability program.

However, the severe price spikes during winter 2013-14 were reflected in much higher contract prices for electricity consumers, including standard offer customers, for the coming year (winter 2014-15). Table 4 shows rate increases for the two largest New England distribution companies due mostly to the higher contract costs for power supplies. Note that the bill impact, while still substantial, is less than the basic service rate increase because basic service changes only impacts the energy portion of the bill, and not the customer service charge, the transmissions and distribution charges, and other factors.

Table 4. Electricity rate and bill increase (Winter 2015 compared to Winter 2014)

Utility	Basic Service Rate Increase	Average Bill Impact
National Grid (MA)		
Residential	96%	49%
Commercial/Industrial	118%	75%
NSTAR (MA)		
Residential	60%	29%
Commercial/Industrial	96%	68%

Source: Presentation by MA DOER Commissioner Mark Sylvia at NE Electric Restructuring Roundtable (11/21/14).

For the recent winter, 2014-2015, the ISO expanded the program to include LNG supplies as well as the dual-fuel and demand response resources from the previous winter. This year the program had available LNG and oil equivalent to almost 4 million barrels of oil. Due to a variety of factors, including low-cost oil, abundant LNG supplies, and a less severe winter (in terms of when and how much electricity was needed), the price spikes were subdued this winter (lowering the overall cost of electricity compared to 2013-2104) and the total ISO Winter Reliability program cost will be even less than last year, under $50 million.

The ISO intends to continue the Winter Reliability program with some additional small modifications for the next three winters (2015-2016; 2016-2017, and 2017-2018) until the forward capacity market (FCM) redesign goes into effect for the winter of 2018-2019.[8] More details on the Winter Reliability Programs to date are in Appendix A.

Adjusting to Poor Resource Performance

Beginning in 2011, ISO-NE began discussions on how to improve resource performance and resource availability. This lead to a proposal by ISO New England to redesign the forward capacity market (FCM)

[8] There is some uncertainty due to a recent FERC Order asking the ISO to develop a market-based approach for the three winters prior to the FCM re-design taking effect. The ISO has told the Commission that its market-based approach is the FCM re-design, already approved, and that the Winter Reliability programs are just an interim approach.

so that resources that cleared in the FCM would face large penalties any time they do not fully perform during a shortage event (whenever reserve resources are needed). Concurrently, resources that perform above their requirements during a shortage event would receive performance payments—such that the entire mechanism is designed to be revenue neutral. The FERC approved ISO's FCM re-design (aka Pay-For-Performance) in early 2014 and the ISO implemented the changes for the forward capacity auction for the 2018-2019 delivery years. That auction occurred in February 2015.

The intent of the "pay for performance" modifications was to address several different performance issues. Some resources are available only at limited intervals, whether due to maintenance issues, fuel issues, or operational issues. The ISO wanted a comprehensive proposal that could address the problem of aging (near retirement) resources, the lack of gas supplies in the winter, and the variable nature of new resources (wind, solar, demand response) and traditional resources (hydro, gas, oil, nuclear). In simple terms, resources that perform when most needed are rewarded through payments derived from the penalties that are applied to those resources that fail to perform to their full obligation. The size of the penalties are significant; they begin at $2,000/MWh starting in June 2018 (the first year); increasing to $3,500/MWh in June 2021; and capping out at $5,455/MWh in June 2024. The penalties are triggered anytime the ISO experiences a shortage event, which is a need to activate its reserves. Shortage events are unpredictable and can occur in any season; they are more likely to correlate to days with high peak demand, but they can also occur on relatively light load days.

FERC approved the FCM changes in early 2014 and the ISO implemented them for the most recent auction that occurred in February 2015. The resources that received capacity supply obligations in that auction will be subject to pay-for-performance rules starting in June 2018. ISO New England anticipates that poor performing resources will take steps to perform better or risk exposure to unpredictable system events (weather, storms, equipment failures, etc.) that will impose significant financial burdens.

2.4. Proposed Electricity Infrastructure

Current expansions and additions to the New England bulk power system are either reliability upgrades needed to avoid current or future violations of reliability criteria or merchant transmission projects that private developers are proposing to import more electricity into major load centers in the three southern New England states primarily for economic or environmental purposes, or both.

Reliability Upgrades

There are numerous reliability upgrades for proposed additions and expansions to the New England electric grid. The Planning Advisory Committee has over a dozen meetings every year to review the need assessments for reliability upgrades and the solution studies for previously identified needs. Over a three year period, the ISO reviews each local segment of the entire New England grid. One of the biggest drivers of reliability upgrades in recent years has been the announced retirement of over 3,000 MW of generation resources (Salem Harbor, Norwalk Harbor, Vermont Yankee, Brayton Point, and Mount Tom, and Brayton Point). These are all coal, oil, and nuclear resources that are no longer economic to operate. The potential for additional retirements in the near future will likely require more reliability upgrades.

Table 5. Announced retirements in ISO-NE

Facility Name	Capacity (MW)	Fuel Type	Retirement Date
Massachusetts			
Brayton Point	1,535	Coal	2017
Salem Harbor	749	Coal/Oil	2014
Mt. Tom	142	Coal	2018
Vermont			
Vermont Yankee	604	Nuclear	2014
Connecticut			
Norwalk Harbor	340	Oil	2013

Source: Synapse Energy Economics

Most of the transmission system in New England was developed to meet reliability needs and was paid through a cost-sharing mechanism among all New England electric utilities and ultimately their customers. The mechanism is based on each utility's contribution to historical peak loads and is revised on an annual basis. Table 6 shows the current pro-rata allocation by state, based on the percent of peak load in each state. The mechanism is more granular with costs actually assigned to each distribution utility in the state based on their specific contributions to peak load. The table shows that these percentages are relatively consistent year to year; nonetheless, small changes have significant impacts to the costs assigned to each utility and its customers. The "Summer 50/50 Net of PDR" means the coincident peak load (all of New England) on an average summer peak day of 90 degrees (50/50 forecast amount) that is reduced by all the energy efficiency resources (Net Passive Demand Resources) to show the expected electrical load on the ISO system on that peak day.

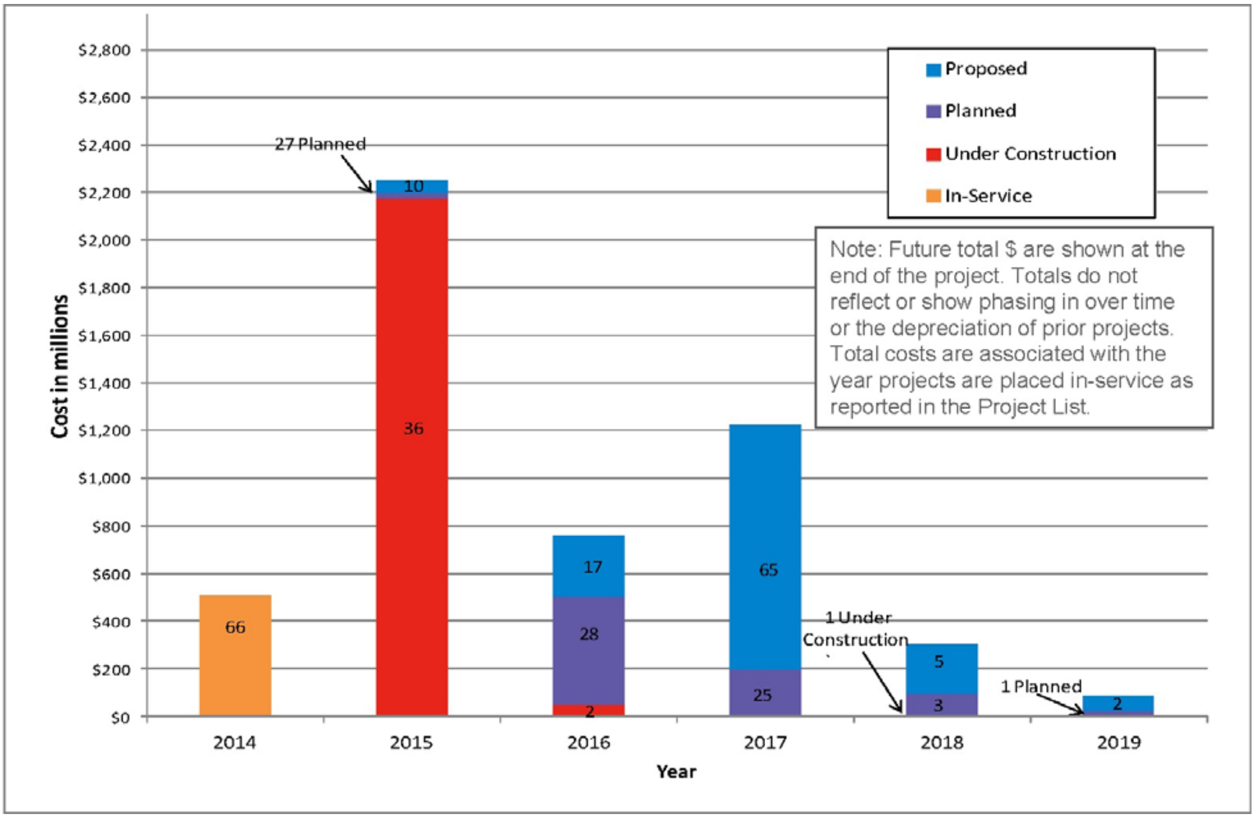
Table 6. 2014 coincident peak loads by state

% of ISO-NE	Summer 50/50 Net PDR		
	2012	2013	2014
Connecticut	26.2%	26.0%	26.2%
Maine	7.5%	7.4%	7.4%
Massachusetts	46.6%	46.9%	46.5%
New Hampshire	8.9%	9.2%	9.3%
Rhode Island	6.9%	6.8%	6.9%
Vermont	3.8%	3.7%	3.7%

Source: ISO-NE Reliability Committee; Source: ISO-NE CELT Forecasts, 2012-2014, Forecast Data, Tab 2.

The cumulative impact of reliability upgrades can be substantial. In each annual Regional System Plan, ISO New England provides a summary of recent changes to the RNS rate and anticipated future RNS rates. The figure below from RSP 2014 shows the estimated impact of new reliability projects that will be included in future RNS rates. All told, the figure shows around $5 billion of new transmission projects (just for reliability purposes) in New England going in service between 2014 and 2019.

Figure 13. Transmission project investment by status through 2019



Source: ISO-NE March 2015 RSP project list update, PAC meeting March 24, 2015.

At least twice a year the ISO provides a large spreadsheet with all approved and proposed reliability upgrades called the Regional System Plan Project List. The most recent version of that spreadsheet from March 2015 is summarized in Appendix D along with a link to the actual document.

Greater Boston Case Study

In February 2015, ISO New England provided a detailed analysis of two competing solutions to resolve reliability criteria violations in the Greater Boston area. A needs assessment done in 2009 identified future reliability violations and a re-assessment in 2013 confirmed the need for a transmission solution. Eversource and National Grid (TOs), the incumbent transmission providers, developed a solution based on an expansion of the existing transmission corridor to allow for additional alternating current (AC) transmission lines and related facility upgrades. New Hampshire Transmission (NHT), an independent transmission provider, developed a solution based on a direct current (DC) underwater cable from

Seabrook, NH, to Everett, MA, and related facility upgrades. ISO New England reviewed both proposals and determined that either one of them would resolve the reliability violations in Greater Boston.

Each solution was evaluated for its estimated costs. The AC solution was estimated to cost $740 million and the DC solution was estimated at $1,025 million; the difference between the two is $285 million. Both proposed solutions contained common elements; the cost difference for the unique elements in each proposal was $289 million. Both the TOs and NHT disputed the other's estimate so the ISO hired an independent consultant to evaluate the cost elements for each proposal. That analysis showed that the NHT proposed solution was more expensive by $245 million.

ISO New England concluded that the AC solution was the less costly option and selected it as the preferred solution. Eversource and National Grid will now build the AC solution and recover all prudently incurred costs (even if they exceed the initial estimates) through the ISO regional tariff once each component is in service and the incurred costs are reviewed and approved by ISO New England and FERC. The entire project is anticipated to be completed in April 2018.

Economic Upgrades

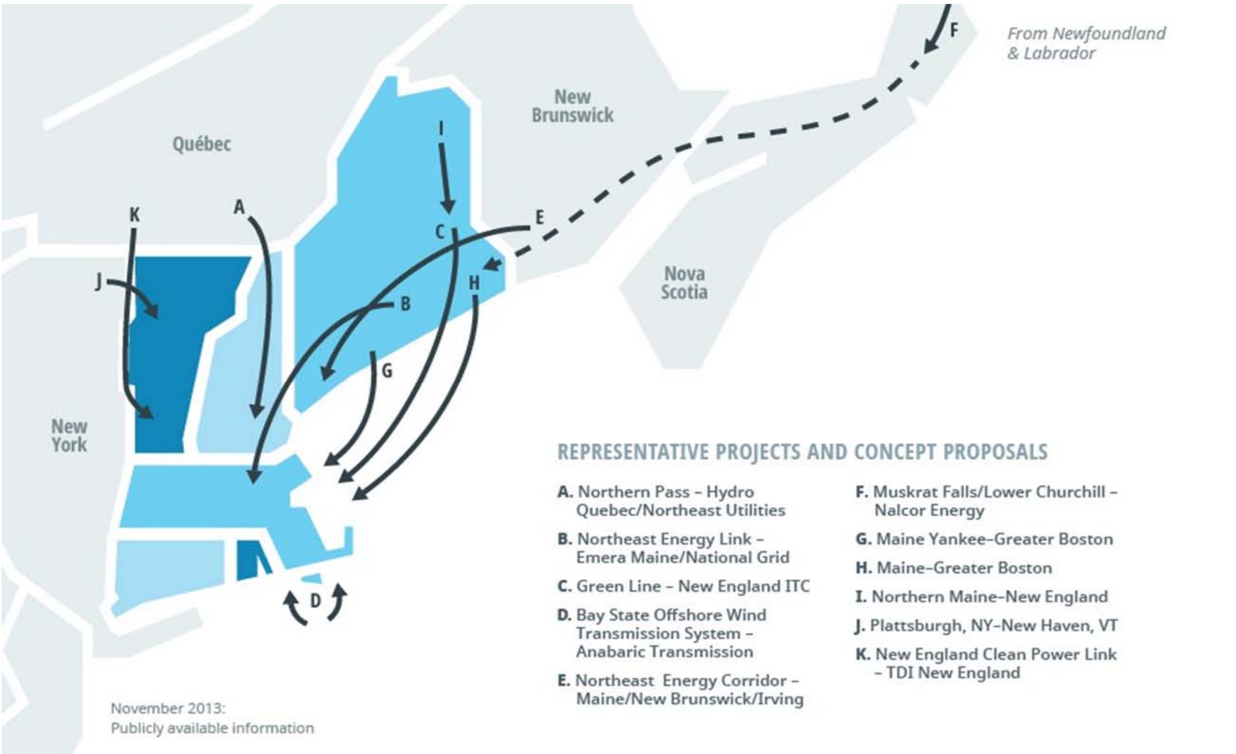
Merchant transmission upgrades have been proposed by numerous entities.[9] They almost all focus on delivering renewable resources to southern New England load centers. Some of the more prominent proposals ones are shown on the map in Figure 14.

These merchant projects include the Northern Pass proposal from Hydro/Quebec and Eversource (previously known as Northeast Utilities) that would deliver up to 1,200 MW from Quebec to southern New Hampshire.[10] Numerous other proposals are focused on Maine wind resources and linking them to the 345 kV lines in southern New England (some by land and some by sea). Other proposals connect with resources in New Brunswick and ultimately Newfoundland; one proposal is focused on offshore wind near Rhode island; and another HVDC line with Quebec coming south through Vermont. Table 7 shows information from the RSP project list for each merchant proposal.

[9] Market efficiency upgrades and public policy upgrades would also be included in this category of non-reliability upgrades if any are actually proposed.

[10] Northern Pass received initial approval from ISO-NE as a proposed plan in December 2013.

Figure 14. Proposed transmission enhancements



Source: ISO-NE, 2014 RSP, Figure 7-3, page 182.

Table 7. Proposed merchant transmission projects in New England

Project	Summary	Ownership	Proposed in service	PPA?	Status?
Northern Pass Transmission Project	1200 MW HVDC connection from Quebec (Des Cantons) to Franklin, NH, and a 345 kV connection from Franklin to Deerfield, NH	Hydro-Quebec/Northeast Utilities	2018	12/31/2013	-
Northeast Energy Link	1100 MW HVDC between Orrington (ME) substation to Tewksbury (MA) substation	Emera Maine/National Grid	6/2017	No	Concept, w/ other proposals cancelled
Green Line	Hybrid land-sea HVDC to bring 1000 MW of wind from northern Maine to eastern Massachusetts	New England ITC/Anbaric Transmission	-	-	-
Bay State Offshore Wind Transmission System	Two 1,000 MW HVDC lines and an onshore converter station, connecting wind south of Martha's Vineyard to the MA southern coast	Anbaric Transmission	-	-	-
Northeast Energy Corridor	1200 MW AC to HVDC Tie. NB 345 kV Keswick or St. Andre substation to NGRID 345 kV Wakefield substation	National Grid	03/2019	No	Concept
Muskrat Falls/Lower Churchill	Bringing power from the new Hydro facility at Muskrat Falls to Nova Scotia, and increasing the NS-NB tie, and carrying it through to ME?	Nalcor Energy	-	-	-
Maine Yankee	1000 MW HVDC from CMP ME Yankee 345 kV substation to Eversource Mystic 345 kV substation, or to Eversource K Street 115 kV substation	Eversource	12/2018	No	Concept, w/ other proposals cancelled
Northern Maine-New England	345 kV Tie Phase 1: 200 MW Houlton, ME to MEPCO 396 Line and Phase 2: MEPCO 396 Line to Bridgewater, ME	Emera Maine	12/2016	No	Concept, w/ other proposal cancelled
Plattsburgh, NY-New Haven, VT	400 MW 150 kV HVDC Line: NYPA 230/115 kV substation in Plattsburg, NY to near VELCO 345 kV New Haven Substation	VEPCO/NYPA	06/2018	No	Concept
New England Clean Power Link	1000 MW HVDC Tie HQ to VELCO 345 kV Coolidge Substation	VEPCO	12/2017	No	Concept

Sources: ISO-NE, 2014 RSP, Figure 7-3, Page 182. And: ISO-NE, Final RSP 15 Project List – March 2015. Both available at: http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

3. GAS SYSTEM

3.1. Gas Pipeline Approval Process

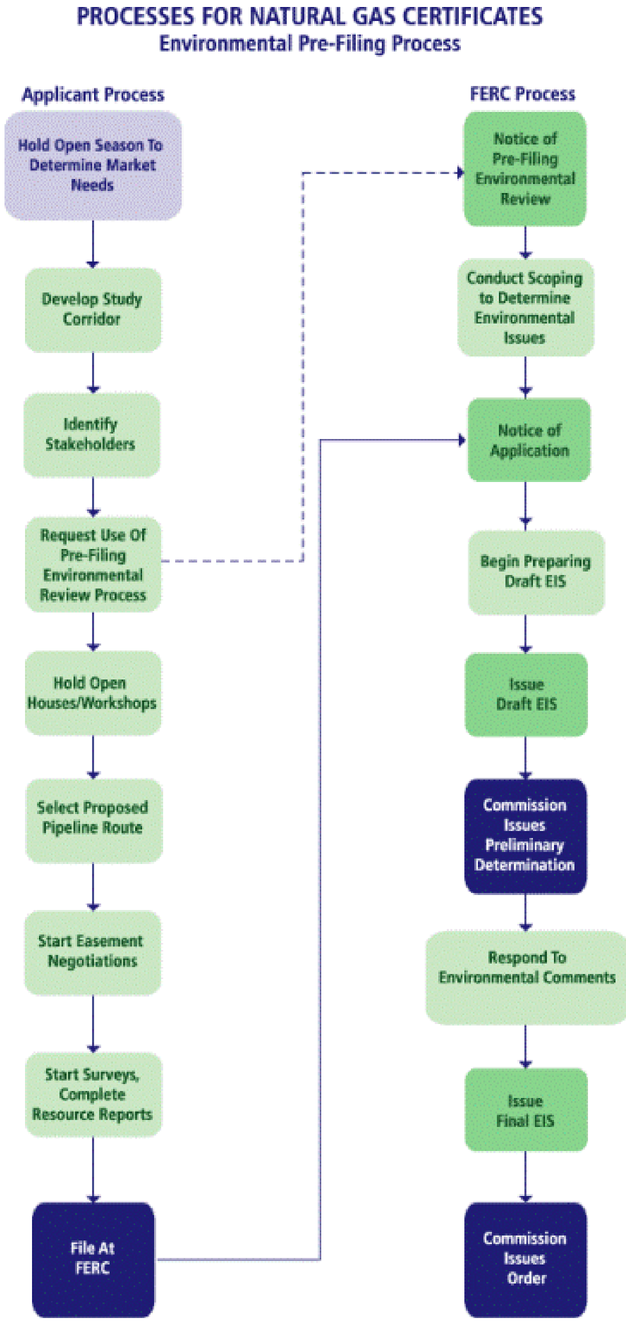
In sharp contrast to the electric transmission review and approval process where the states play a large role, for interstate gas pipelines the primary jurisdiction is with the Federal Energy Regulatory Commission (FERC). In fact for interstate gas pipelines FERC has preemptive siting authority over the states, can allow developers onto private property to conduct survey work and even exercise eminent domain if need be, and approves the firm gas rates (recourse rates) for the pipelines. However, distribution level pipelines that deliver gas to end-use customers (and don't cross state lines) are only subject to that state's jurisdiction for siting, health and safety, and cost recovery issues.

FERC's gas pipeline certification process, shown below in Figure 15, includes a "pre-filing environmental review process" that is required for liquefied natural gas (LNG) facilities and strongly encouraged for natural gas pipelines (and according to FERC this almost always is used for gas pipelines as well). The purpose of the pre-filing process is to facilitate maximum participation from all interested entities and individuals and to assist an applicant in compiling the information needed to file a complete application. FERC's goal is to allow the Commission to process the ultimate application expeditiously (i.e., within one year after the application is formally filed following the pre-filing process). FERC expects the pre-application process to take at least a year for "extensive" projects and somewhat less for facilities built mainly in existing rights-of-way.

Applicants are required to reach out and seek input from stakeholders which FERC defines as "a Federal, State, or multistate, Tribal, or local agency, any affected non-governmental organization, or other interested person (including citizens along the likely pipeline path). The applicant must provide stakeholders with information about the proposed project as well as a reasonable opportunity to present their views and recommendations with respect to the need for and impact of a facility covered by the permit application. This has typically been handled in the gas pipeline pre-filing processes by holding a series of "open houses" at strategic geographic locations along the proposed route. There are no firm rules explaining how these open houses ought to be structured, but the goal is to foster two-way communication between the applicant and all relevant stakeholders. In the past, they involved informal workshops, formal transcribed testimonials or simply information booths offering descriptions of various aspects of the proposed projects. Applicants are also expected to coordinate with any separate permitting and environmental reviews by other federal, state, or local agencies. At the beginning of the pre-filing process, each applicant must file a "Participation Plan" and develop a project specific website.

This prefiling phase is also typically the time during which state siting councils/boards will initially weigh in on a project. For instance, in Massachusetts, the Energy Facility Siting Board will conduct its own public hearings on a pipeline project and will provide comments to FERC to try and improve the project design and reduce environmental impacts. The state siting board can also require landowners to provide access to a developer for survey purposes if requested by a developer and after holding an investigation.

Figure 15. Gas pipeline applicant and FERC review and approval process



Source: FERC

Under the electricity section, we discussed several different types of transmission projects that come before FERC including transmission proposals that are either primarily to address reliability, economic needs, or public policy issues. In many ways proposals to build or enhance interstate gas pipelines are analogous to building transmission to meet economic (rather than reliability) needs. As such pipeline developers, prior to officially filing their pipeline applications at FERC also hold “open seasons” to first identify potential purchasers/customers of their proposed new/incremental gas supplies (referred to as shippers), and later to secure firm long-term contracts with gas shippers. This showing of interest (ultimately through firm gas contracts), is used to demonstrate “economic need” at FERC. Generally, it is rare for pipeline developers to formally file their application without 80-100% of their expected gas volume already committed in firm contracts with customers (shippers).

Once firm contracts are negotiated between the developer and local distribution companies, they would be submitted first to the state regulator for review and approval. These are called “precedent agreements” (as they precede the actual FERC approval of the pipeline). Typically, since the final pipeline size and gas pricing aren’t yet known at this pre-filing stage, the contracts are generally structured as not-to-exceed amounts with a most-favored nation clause that would entitle the buyer to lower prices if warranted by the ultimate size, design, and pricing. Typically these contracts are approved by state PUCs in under a year. With these anchor tenant contracts in hand (again typically for a majority of the gas to be supplied by the pipeline), and the pre-filing public engagement process complete, the developer can formally file at FERC.

When an applicant files a formal notice following the pre-filing process, it must include a summary of the points made by stakeholders during the pre-filing process and indicate how, if at all, it has addressed them. It is important to note, however, that while the gas pipeline pre-filing siting processes is structured to both inform stakeholders about the proposed project and to garner their input, it is not designed as formal consensus-seeking efforts. This does not preclude an applicant from modifying its initial plan in response to concerns raised during the pre-filing process. Nor are applicants forbidden from commencing negotiations on their own with local landowners and communities about land easements and any other matters, at any time they prefer. Once a formal application has been filed, FERC begins its legally-mandated process and stakeholders that want to continue to be involved must formally intervene (by filing a motion) in the case.

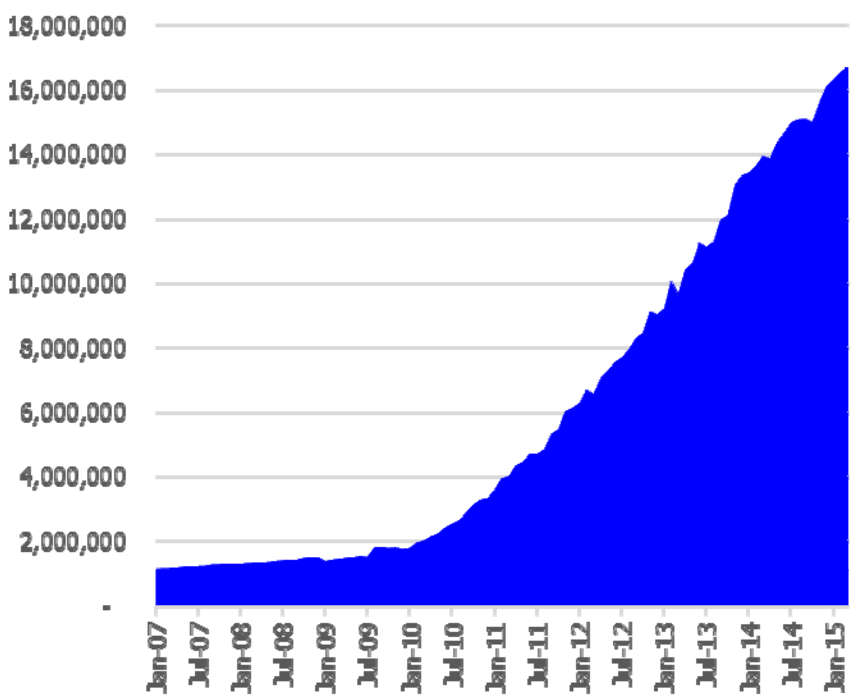
Once filed at FERC (including any and all precedent agreements with buyers), FERC orchestrates a NEPA environmental review of the project engaging other relevant federal agencies. FERC’s review typically takes up to a year. The state energy facility siting councils typically intervene at FERC to represent the state in their proceedings. FERC also looks at the need for the project, but if there are buyers lined up, the project is generally assumed to be needed. Once the pipeline review is deemed complete including the Environmental Impact Statement, FERC approves the project (often with conditions), issues a certificate that allows the developer to begin construction, and approves the “recourse rates” for firm service for off-take along the pipe. At this point, interveners in the case have 30 days to request a rehearing (as just happened in the AIM pipeline case in Boston—see Section 3.3 below for more details about AIM), and FERC’s decisions are appealable to the court.

Because these are essentially “economic” projects, with pipeline companies only seeking approval once they have their customers largely lined up—FERC would not normally be making a determination regarding whether a region like New England “needs” an additional 1, 2, or more Bcf/day. So if both Kinder Morgan with its NED project, and Spectra/Eversource/National Grid with its Access Northeast project (see Section 3.3 below for detailed descriptions of these pipeline proposals), each come to FERC with 1 Bcf pipeline project proposals, and the gas is being sold to different customers/shippers through long-term contracts (whether it's for heating or electricity generation or both), it would not be FERC's job to pick between the projects nor to reject a proposal because of concerns about potential future stranded costs to the pipelines. Nor is it FERC's role to assess how either or both projects could impact meeting the region's climate goals

3.2. Gas Infrastructure

Natural gas has become increasingly important in New England over the past decade. With falling gas prices due to increasing U.S. gas production as a result of new drilling techniques (fracking and horizontal drilling) most notably from the Marcellus Shale in and around Pennsylvania (currently producing around 15 billion cubic feet (Bcf) of natural gas per day) (See Figure 16), and the alleged advantages of natural gas over coal and oil from a greenhouse gas perspective—natural gas utilization in New England has increased in both the electricity and home heating sectors. Natural gas is now responsible for approximately 50% of electricity generation in New England—up from only 10-15% a mere decade ago. Home heating has also seen a large uptick in New England—everywhere that natural gas is available (i.e., natural gas distribution pipelines). Natural gas now comprises approximately 30% of all primary energy consumed for all sectors in New England.

Figure 16. Marcellus production 2007-2015, Mcf/day

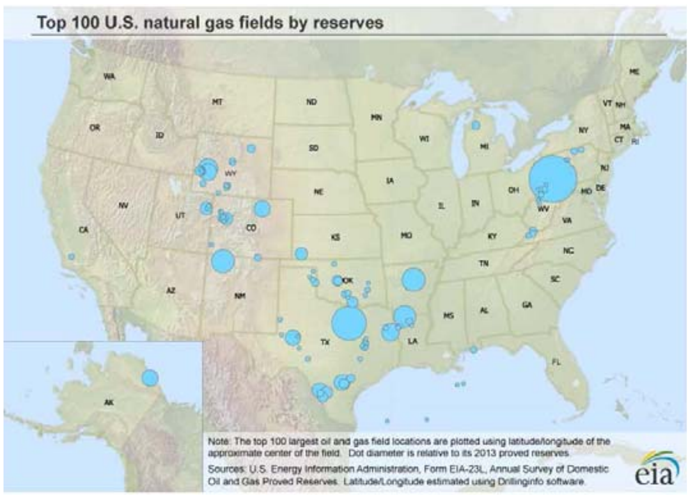


Source: Provided by Northeast Gas Assocation

Changing Northeast Gas Supply Dynamic

New England traditionally has been considered “at the end of the pipeline” and constrained on delivery points. Historically, its gas supplies came predominantly from the U.S. Gulf Coast, western Canada, offshore eastern Canada, and imported LNG. The advent of Marcellus shale gas development starting around 2007 is changing the entire regional supply dynamic. The Marcellus is now ranked as having the largest gas resource base potential in the U.S. (See Figure 17). In recent years, output has been increasing and prices are relatively low. The current focus in the Marcellus production area – principally Pennsylvania and West Virginia – is on the development of pipeline infrastructure to get the produced gas to market – whether the Northeast, southern U.S., or even Canada.

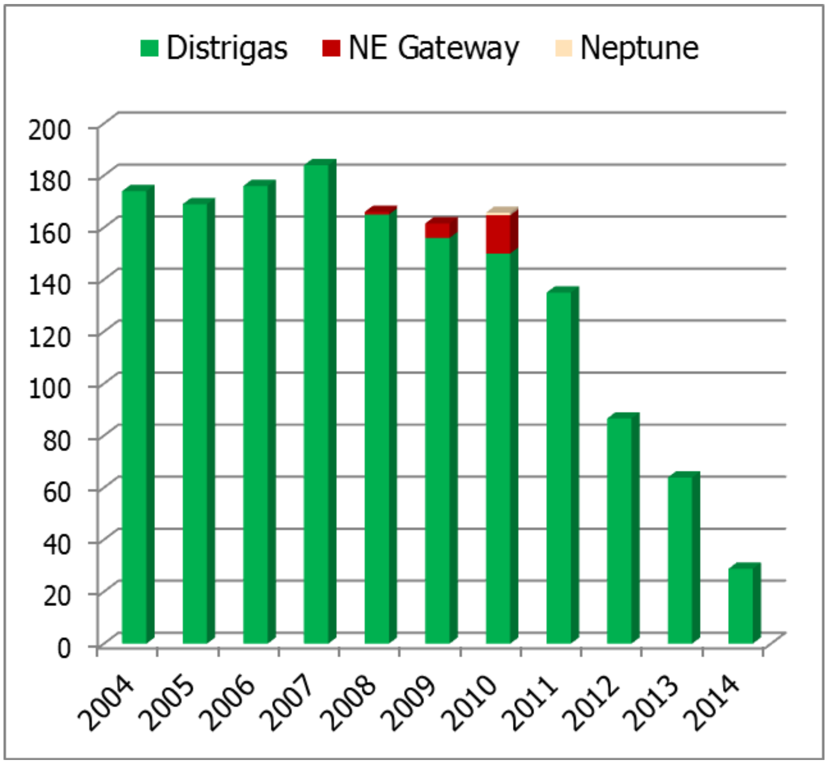
Figure 17. Top 100 U.S. natural gas fields by reserves



Source: U.S. EIA’s gas resource map of April 2015 presents the Marcellus region as the largest gas resource base in the U.S.

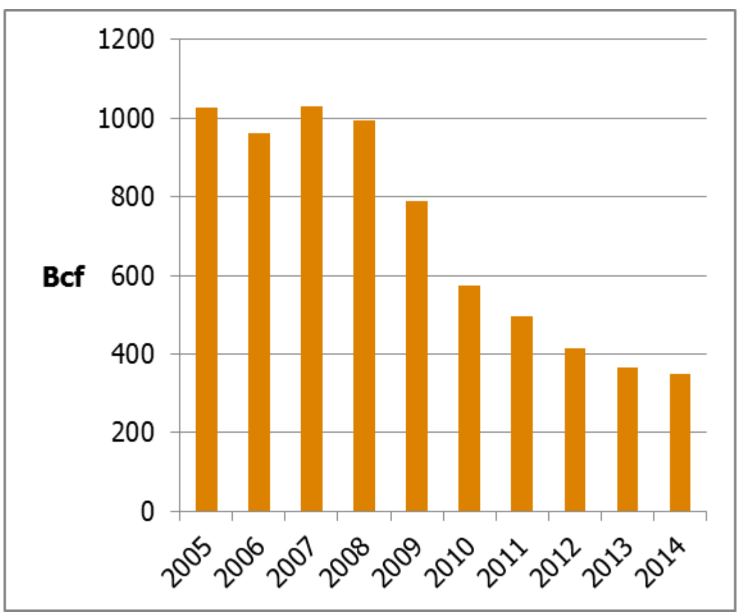
For New England, the dilemma is that the pipelines to the “west” (i.e., New York & Pennsylvania) are essentially full as more and more of the market seeks to source its gas at Marcellus. Canadian and LNG imports have dropped fairly dramatically in recent years as a result of this changing dynamic. The Canadian pipelines and LNG import facilities are increasingly underutilized while at the same time pipeline proposals have emerged to increase delivery capacity from the “west” end of the region.

Figure 18. LNG exports by New England based terminals 2004-14 (Bcf/year)



Source: U.S. Dept. of Energy/Office of Fossil Energy, 2-15.

Figure 19. Canadian natural gas export to eastern U.S., 2005-14

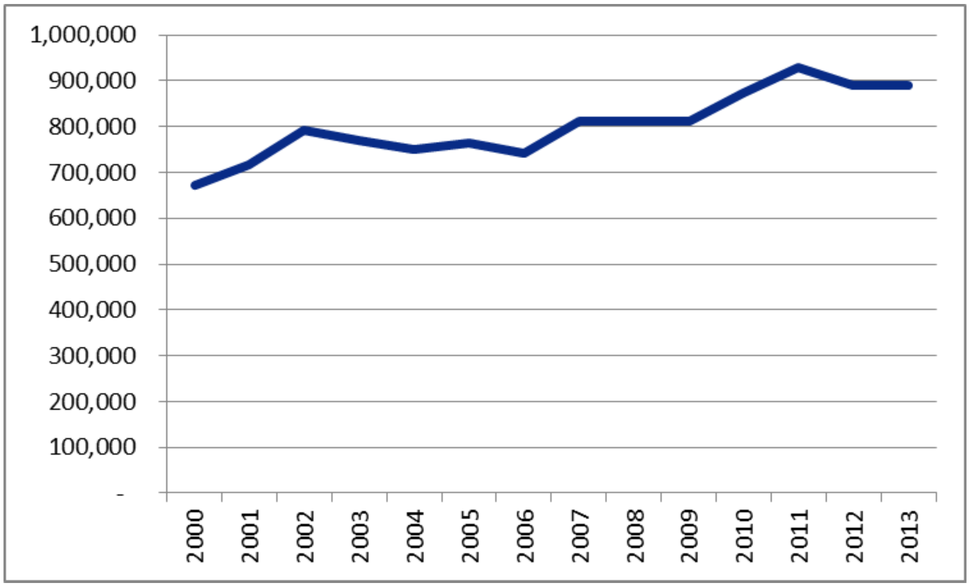


Source: National Energy Board, Canada.

Gas Demand

New England currently has 2.6 million gas customers that consume nearly 900 billion cubic feet (BCF) of natural gas/year at cost of around $3.5 billion per year (by comparison Marcellus Shale is currently producing around 15 Bcf/day—60 days of production could theoretically supply New England for a year). As shown in Figure 20, natural gas demand has risen nearly 40% since 2000 from around 650 Bcf to 900 Bcf per year.

Figure 20. New England gas consumption 2000-2013 (MMcf)



Source: Developed by Raab Associates using EIA Natural Gas Data

Of the natural gas used in New England in 2013, as Table 8 shows, 41% was used for electricity generation, 25% in the residential sector (largely for space and water heating), 19% in the commercial sector (also largely for heating), and 15% in the industrial sector. Half of the gas was used in Massachusetts, one quarter in Connecticut, and the last quarter in the other four New England states.

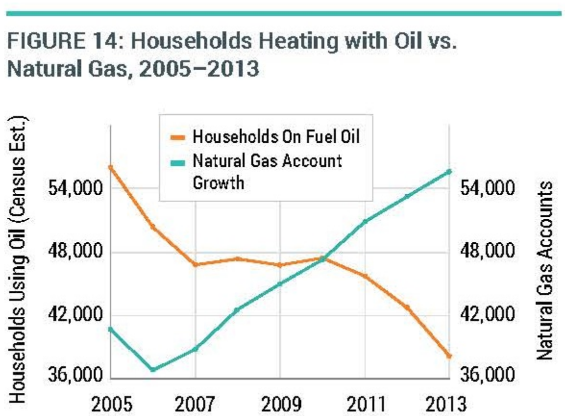
Table 8. New England natural gas consumption: By state & by sector (2013 in BCF/Year)

	Residential	Commercial	Industrial	Electric Power	Total	Percent State
Connecticut	47	46	30	107	230	26%
Maine	2	8	32	21	63	7%
Massachusetts	140	90	50	156	437	50%
New Hampshire	7	9	8	30	54	6%
Rhode Island	18	12	8	47	85	10%
Vermont	3	5	1		9	1%
New England	217	170	129	361	878	100%
Percent End Use	25%	19%	15%	41%	100%	

Source: Developed by Raab Associates using EIA Natural Gas Data.

In Massachusetts, approximately half of the homes heat with natural gas as their primary fuel source, and similar to the region approximately half of the electricity generation is fueled by natural gas. In Boston home heating with natural gas increased from around 36,000 homes in 2006 to 54,000 homes in 2013—a 50% increase in only seven years (see Figure 21).

Figure 21. Boston household natural gas and oil heating—2006-13



Source: Boston Climate Plan.

All told, New England currently consumes less than 3 Bcf/day of natural gas for all end-uses on average, although on peak winter days natural gas consumption is higher at 5-6 Bcf/day—and more would likely be consumed on those winter days (e.g., through increased utilization of the gas-fired electricity generators) if New England wasn't pipeline constrained.

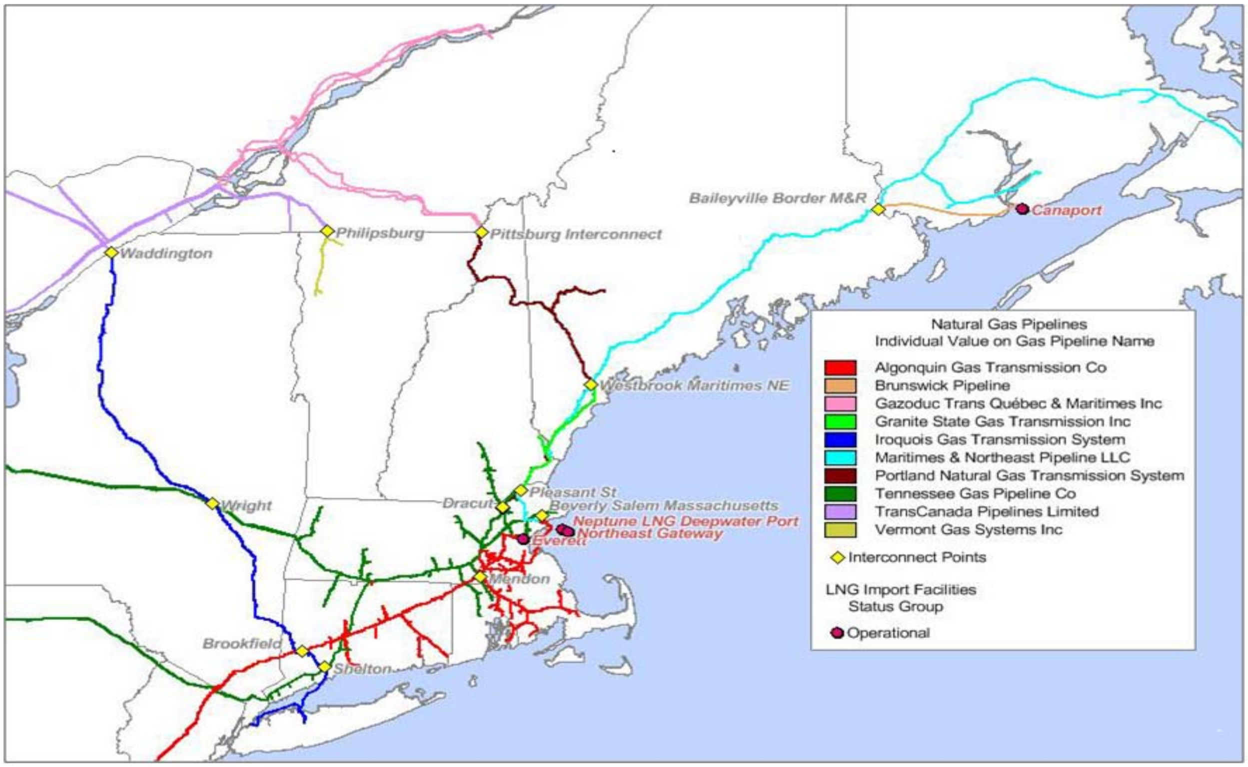
Gas Supply

There are currently five interstate pipelines into New England, with 2,588 miles of pipe (See Figure 22). In addition, New England has four liquefied natural gas facilities that are also capable of bringing natural gas into New England—(See Figure 23 including their capacities). Three of the five New England pipelines and three of the four LNG terminals bring natural gas directly into Massachusetts (See Table 9). Once in Massachusetts, the natural gas is delivered to end use customers by eleven natural gas distribution utilities through more than 21,000 miles of distribution pipes.

The current gas pipeline capacity into New England is 3.8 Bcf/day. LNG capacity into New England is designed to provide potentially 1.5 Bcf/day of gas when vaporized into the pipeline system (.7 from Distrigas at Everett and .8 off-shore from 2 facilities), but that LNG can only be delivered through the existing interstate pipeline system which has deliverability limitations.

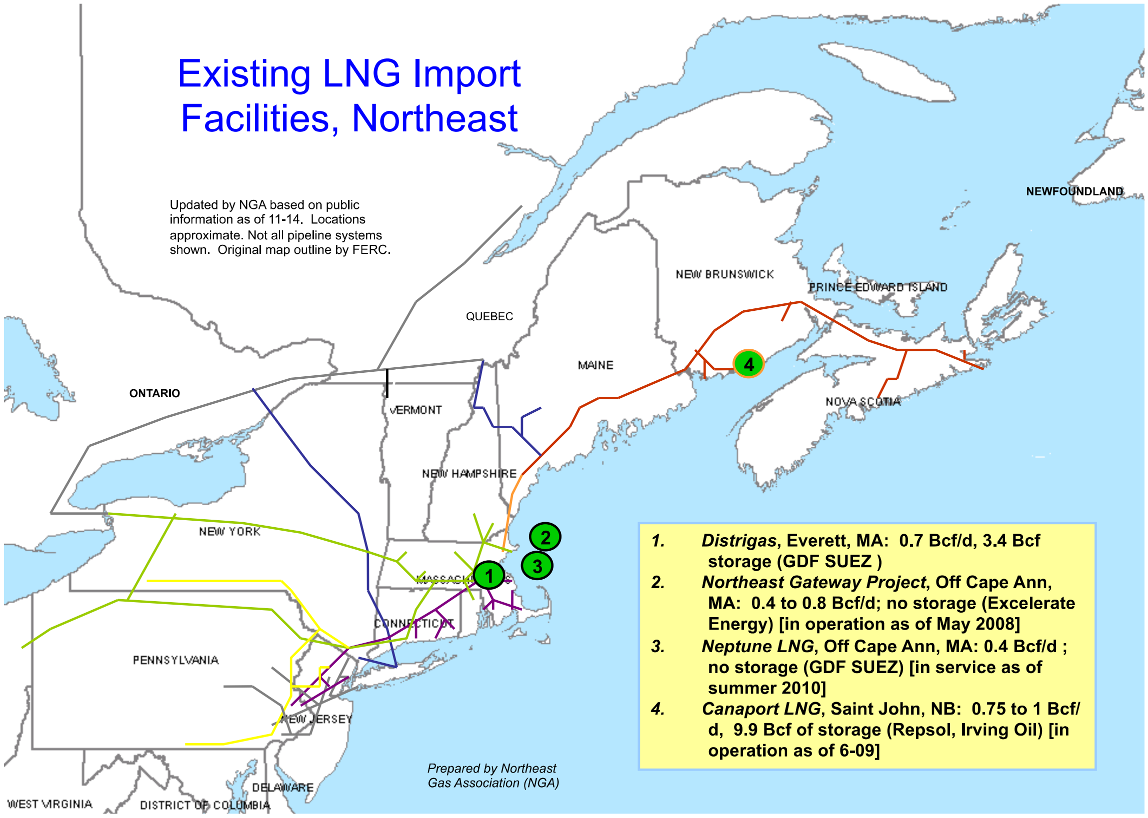
There are also LNG storage/peak-shaving facilities in five New England states with a total storage capacity of 16 Bcf –11 Bcf of which is located in Massachusetts and owned by local gas distribution utilities in 18 communities. Local gas distribution companies can in theory inject approximately 1.4 Bcf/day from the 16 Bcf of total stored regional LNG directly into their distribution pipelines, thereby supplementing the interstate pipeline delivery capability to end use customers (but not typically to power generators) and within the limitations of their limited on-site storage volumes. Utility LNG storage is designed to meet only a few days of peak winter conditions. Also some LNG, on the order of magnitude .1 Bcf/day (or 1 million gallons)—can be distributed by truck from the Distrigas LNG facility in Everett to the various storage facilities throughout New England (none of which are currently located at electric generation facilities).

Figure 22. Existing New England pipelines



Source: Provided by Northeast Gas Association

Figure 23. Existing LNG import facilities in Northeast



Source: Provided by Northeast Gas Association

Table 9. New England major existing pipeline and LNG infrastructure

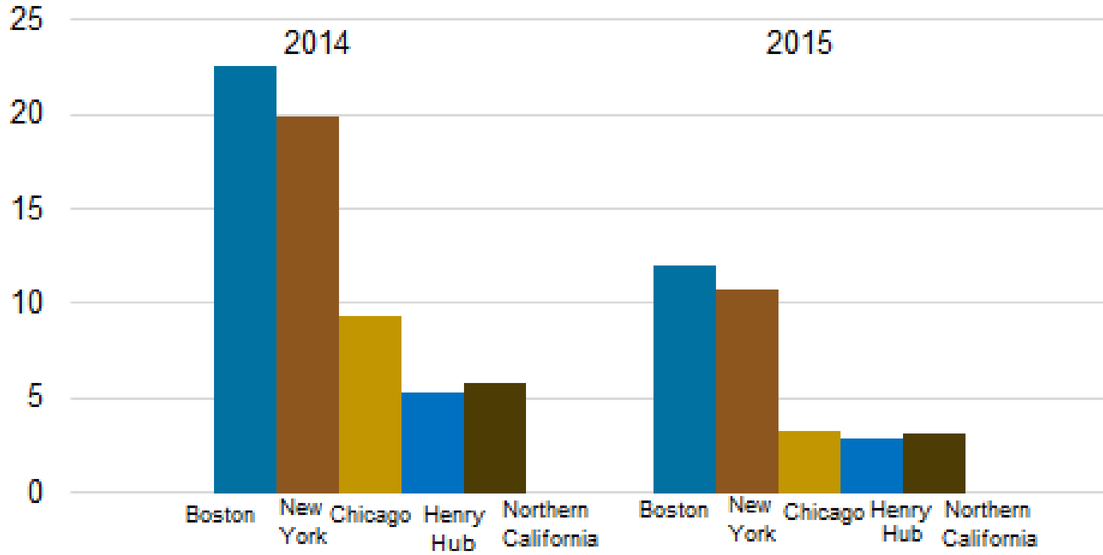
Name	Owner	Capacity	Entry Points
Pipelines:			
Algonquin	Spectra	1.3 Bcf/day	NY/CT/MA/Ri
Tennessee	Kinder Morgan	1.3 Bcf/day	Western MA/Southern CT
Maritimes & Northeast	Spectra, Emera, & Exxon/Mobil	0.8 Bcf/day	New England from Maritimes
Portland Natural Gas Transmission (PNGTS)	TransCanada & Gaz Metro	0.2 Bcf/day	W. Canada to New Hampshire and Maine
Iroquois Gas Transmission	TransCanada, Dominion, Nat'l Grid, etc.	0.2 Bcf/day (of 1.6 Bcf/day capacity delivered to NE)	CT
LNG Facilities:			
Distrigas	GDF Suez	0.7 Bcf/day; 3.4 Bcf storage	Everett
Neptune	GDF Suez	0.4 Bcf/day; no storage	Offshore Cape Ann
Northeast Gateway	Excelerate Energy	0.4-0.8 Bcf/day; no storage	Offshore Cape Ann

Source: Developed by Raab Associates from Northeast Gas Association information

Gas Basis: A New England "Premium"

Because gas demand has been increasing in Massachusetts and New England without commensurate increases in gas delivery capability, prices here have remained high relative to the rest of the U.S.—particularly in the Winter when there is high-demand for natural gas for both electricity generation and heating. As Figure 24 below shows natural gas prices in Boston can be more than 3-4 times higher than the reference Henry Hub gas price—and more expensive than our sister cities New York City and Chicago. While wintertime pipeline natural gas prices were lower in New England in 2015 than they were in 2014, due to a variety of factors including higher LNG imports into the region—pipeline delivered gas prices remained over 3 times higher in New England than at the Henry Hub.

Figure 24. Average wholesale natural gas pricing at key trading locations, east and west for January 1 to February 20 (dollars per million British thermal units)

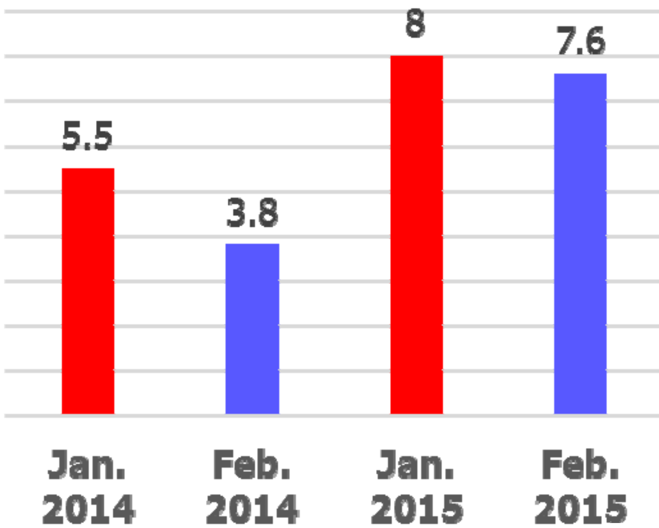


Source: Natural Gas Intelligence retrieved from EIA. Note: The trading hubs represented here are Algonquin Citygate for Boston, Transco Z-6 NY for New York, Chicago Citygate for Chicago, and PG&E Citygate for Northern California. Henry Hub is the standard trading benchmark for U.S. natural gas.

Winter of 2015 vs. 2014

For a variety of reasons, the cost and availability of natural gas this past winter was more favorable than in 2014—hence putting somewhat less pressure on both natural gas and electricity prices. One of the main reasons was a significant increase of LNG imports into New England in 2015. For example, Distrigas alone doubled the amount of imports into the region in February in 2015 compared to February in 2014 from 3.8 to 7.6 Bcf—and one terminal offshore Cape Ann received an LNG cargo for the first time in four years. In addition, the dramatic drop in world oil prices in late 2014 made electricity from oil-fired generators more competitive in the wholesale electricity energy markets. It is also likely that supply contracts and hedging mechanisms have adapted to the extremely high prices driven in large measure by winter spot gas prices.

Figure 25. Monthly import volumes for Distrigas (Bcf)



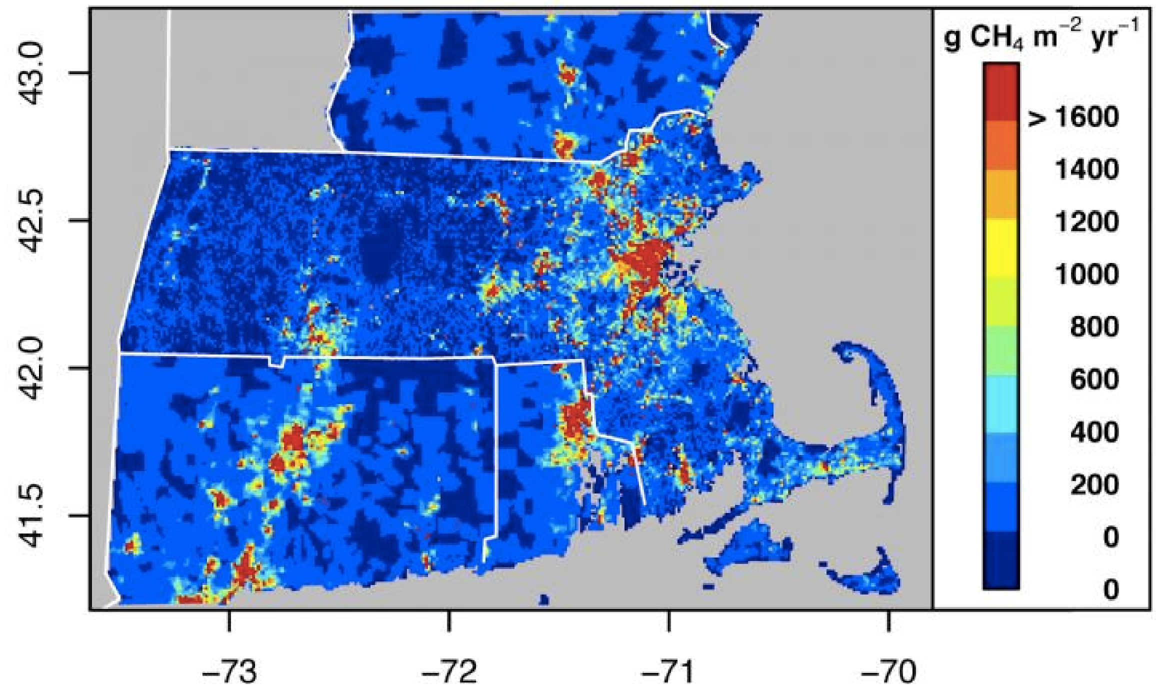
Source: Provided by Northeast Gas Association

GHG Profile of Natural Gas

Natural gas has a lower carbon dioxide (a greenhouse gas) emissions profile than oil or coal at the point of consumption/burning. Hence fuel switching to natural gas from coal/oil for electricity generation and from heating oil and propane for home heating is generally viewed as an important greenhouse gas mitigation measure. However, it's important to note that when natural gas escapes at the point of extraction or during transit from production to end users it's generally emitted as methane (rather than as CO_2). Since methane emissions are roughly 20 times more potent than CO_2 on a pound for pound basis—to the extent that methane is released during extraction and transportation, this reduces the relative greenhouse gas benefits of switching from coal and oil to natural gas.

A recent study by Harvard published in the Proceedings of the National Academy of Sciences mapped the methane leaks from gas distribution systems in New England (see Figure 25 below for methane detection throughout New England). The study estimated that 2.7% of gas intended for delivery to Boston leaks from the distribution system before it reaches end use customers and is released into the atmosphere as methane.

Figure 26. Methane leaks from gas distribution systems in southern New England



Source: McKain, K. et al. 2014. "Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusets. Proceedings of the National Academy of Sciences.

A key factor in Boston and New England methane emission estimates is the older characteristic of the local distribution system. Massachusetts for instance has a larger share of pipe considered "leak-prone" (e.g., cast-iron and bare steel); the MA average is 23.5% compared to the national average of about 7%. In June 2014, the MA Legislature unanimously enacted a bill (H. 4164) to accelerate the replacement of older utility distribution systems, to enhance safety and reduce emissions.

Some experts such as the scientists behind The Solutions Project estimate that when you look at the full fuel cycle (including extraction and transportation/delivery—and not just final combustion), natural gas is not much better than other fossil fuels—and in certain circumstances worse from a greenhouse gas emissions perspective. This has been an area of significant debate.

3.3. Gas System/Supply Proposals

Overview

There is significant interest among the New England states and many (but not all) stakeholder groups for securing some additional natural gas resources for New England. This is in part driven by a desire for additional supply to continue to convert oil and propane-heated buildings to less expensive (and ostensibly lower GHG emitting) natural gas. While the interest in natural gas for heating conversion exists throughout New England, it is particularly important to Northern New England states (ME, NH, and VT) because they have relatively less developed gas pipeline and distribution infrastructure, and over 50% of the buildings are still heated by oil and propane.

However, the biggest driver for increased gas supplies in New England is for electric generation. As discussed above, approximately half of New England's electricity generation fleet now relies on natural gas. But unlike gas utilities that have firm contracts with gas pipelines to deliver gas for their residential and commercial customers, few gas electricity generators have firm long-term contracts for gas supplies—preferring to purchase gas through shorter-term contracts or at spot market prices. The generators thus mostly operate under non-firm or interruptible contracts. They report that the New England power market, which operates on a short-term focus, does not provide sufficient incentives for a generator to enter into a long-term pipeline capacity contract. In the past, other than on very cold winter days, there had been sufficient additional capacity in the gas pipelines to provide gas for electric generators at reasonable prices. This has changed as reliance on natural gas for power generation and space heating has grown. On the coldest days, the pipelines are full and meeting firm contract requirements for residential and commercial heating; hence there is very little non-firm gas available for electric generation. This means for meeting summer electricity demand, there is still a relative abundance of gas for generators at reasonable prices but increasingly during the winter, gas becomes very expensive for generators and at most times in the winter little-to-none is available for non-firm gas generation. During the coldest days when virtually all the gas is used for heating, gas-generators that have dual fuel capability burn oil or propane, while those who don't have dual fuel capability do not run at all.

There are several concerns regarding this scenario. First, there are concerns about reliability of the electric system during cold winter days when the demand for gas for both heating and electricity generation are high—and gas is just not available for electricity generation. Second, there are concerns that the increasingly tight gas supplies combined with the lack of firm contracts for gas-fired generators is driving up electricity costs during the winter months (See Figure 27 on New England gas and electricity spot prices—note close relationship between gas prices and electricity prices in New England). In fact, the high electricity spot market prices from December 2013 through February 2014 resulted in sharp increases in current basic service electricity rates throughout New England by nearly 50% or more in some jurisdictions for this winter compared to last winter. Finally, there are concerns about the environmental impacts of having to rely less on natural gas during the winter months and more on imports, oil, and coal. As Figure 28 shows, on a cold winter peak evening (2/15/15) oil and coal was responsible for 42% of the electricity and natural gas only 17%, despite the fact that nearly half of New England's generation capacity is gas-fired. (February 15, 2015 was also the date that the region's natural gas utilities set a new record for gas delivery.)

Figure 27. New England wholesale electricity and natural gas wholesale prices (2012-15)

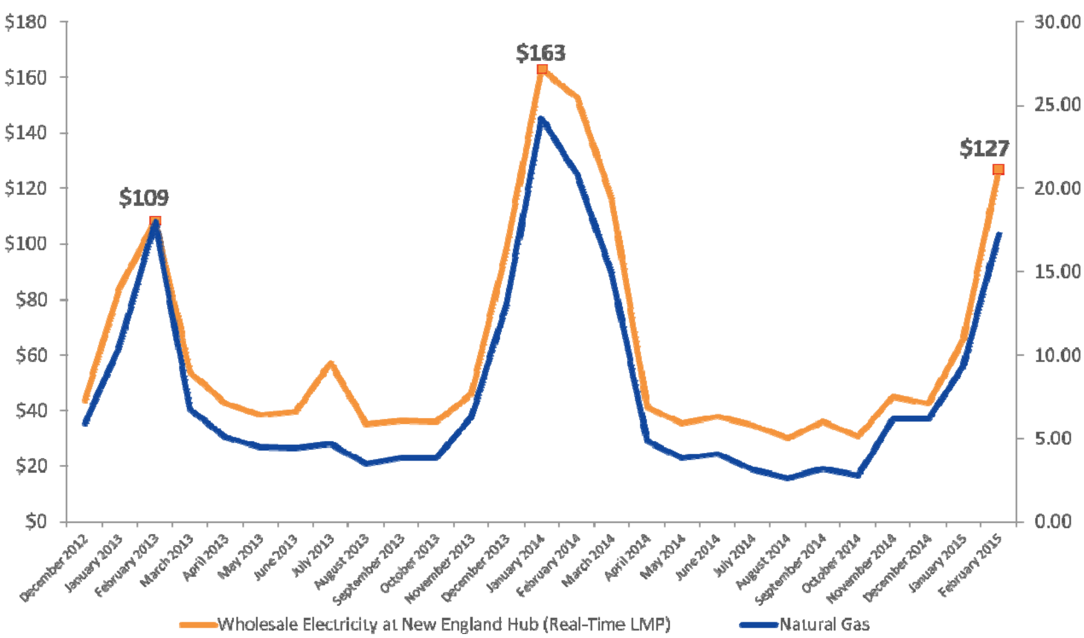
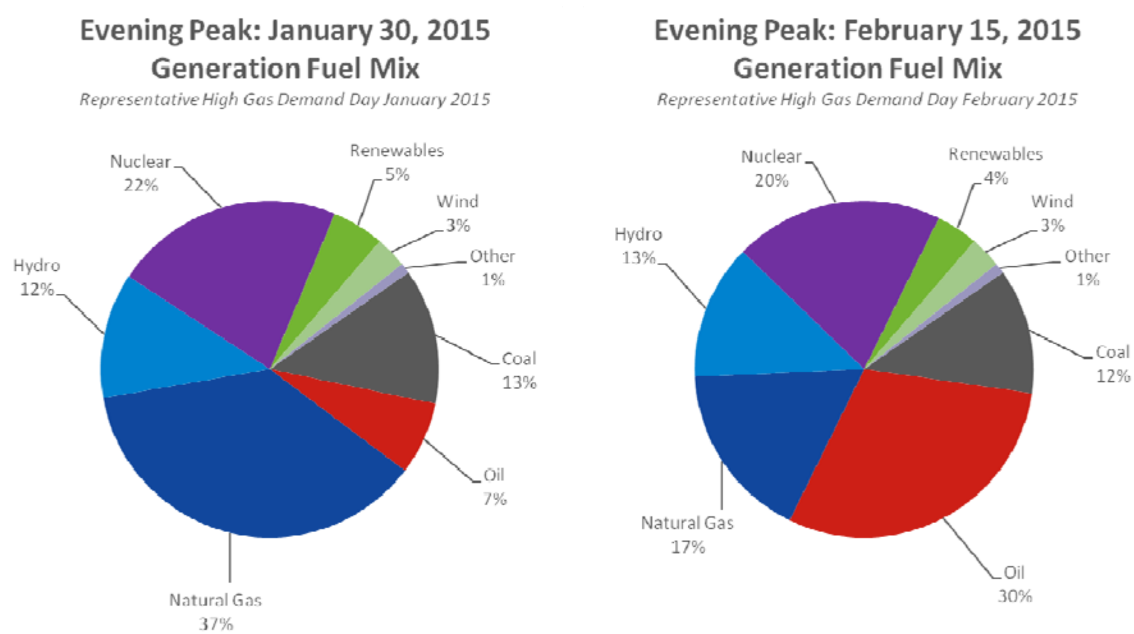


Figure 28. Evening Peak Generation Fuel Mix—Two Winter Evenings 2015



Source: Presentation by Bob Ethier, ISO New England and April, 2015 NE Electricity Restructuring Roundtable

Demand Studies

Three key studies have been undertaken to explore the interface between New England's increasing reliance on natural gas-fired generation, in light of our current gas infrastructure limitations—and to assess whether additional gas infrastructure and supplies will be needed.

- **New England States Committee on Electricity** (NESCOE) hired Black & Vetch to conduct a study in 2012/13 to assess the sufficiency of gas infrastructure to support power generation. From the study, the states concluded that an additional pipeline provides the most substantial economic net benefits to electricity consumers of all solutions studied under the Base Case & High Demand Case. Further analysis would be required to determine whether policies that would result in a Low Demand Scenario are cost-competitive with infrastructure investments.
http://www.nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf

- **Massachusetts Department of Energy Resources** hired Synapse Energy Economics & Raab Associates to conduct a Low Gas Demand Analysis just for Massachusetts (with a stakeholder engagement process) in 2014. The study looked at eight scenarios including four with much more aggressive demand reduction strategies than Massachusetts currently deploys, and two scenarios with increased hydro imports from the north. In the scenarios studied, a need for additional gas pipeline capacity primarily for the power sector is indicated, ranging from 0.6 Bcf/day to 0.8 Bcf/day just for Massachusetts between 2020-30. Interestingly, by 2030, several scenarios showed that incremental gas pipeline expansion needed in the earlier years is no longer required in later years, based on the cumulative acquisition of non-gas resources. This analysis did not require compliance with the Global Warming Solutions act and did not specifically explore potential policies designed to obviate gas pipeline expansion.
http://www.raabassociates.org/Articles/doer-low-demand-report-final.pdf

- **Eastern Interconnect Planning Collaborative (EIPC)** representing the entire electric grid east of the Rocky Mountains hired Levitan Associates with U.S. DOE funding to conduct a Gas-Electric System Interface Study for the Eastern Interconnect including New England in 2014/15. This study also concluded that additional gas infrastructure and supply was needed in New England.
http://www.eipconline.com/uploads/FinalDraftT2Report.pdf

    - *In **ISO-NE**, the gas infrastructure is constrained in winter 2018 and 2023 under nearly all of the market conditions and resource mixes tested in the scenarios and sensitivities. These constraints reflect both commodity supply and transportation deficits. Nearly all of the gas-fired generators in New England lack primary firm entitlements, thereby limiting access to natural gas during cold snaps. The deliverability shortfall is explained by upstream transportation bottlenecks into New England along the major pipeline pathways linking Marcellus with New York and New England, as well as the anticipated continued decline in traditional imports from Canada. Limiting receipts at the LNG import facilities in New Brunswick and Massachusetts increases the deliverability shortfall in New England, particularly on the Algonquin and Tennessee mainlines around Boston. While there are many new pipeline projects on the drawing boards for New England, only Spectra's AIM Project and Tennessee's Connecticut Expansion Project, both comparatively small pipeline expansions, have been incorporated in the scenarios tested, due to the development status of the projects at the time study inputs were set. The affected gas-fired generation is mitigated fully in 2018 and 2023 when high daily spot market gas prices place oil-fired generation, and, to a much lesser extent, coal-fired generation, in merit.*

In case sensitivities, the postulated reutilization of the LNG import terminals at both Canaport and Distrigas materially lessens the amount of affected generation. There are no constraints in summer 2018, but by summer 2023, growth in electric loads increases transportation deficits affecting generation throughout the region.

Given the apparent predicament that New England faces—increasing reliance on natural gas fired generation by generators without firm gas contracts combined with increasing natural gas use for heating in buildings—the New England Governors have been exploring options to spur development of additional gas pipeline capacity. Specifically, they are looking for ways to increase gas supply and infrastructure that would be dedicated more-or-less to gas fired generation (as opposed to gas heating which already has firm gas contracts). One idea that received a lot of attention in 2014 was to consider asking FERC to approve a tariff for wholesale electric ratepayers to pay for gas pipeline capacity dedicated to electric generation. This would have been the first time that FERC was asked to approve such a cross-over wholesale energy ratepayer tariff where electric ratepayers would pay for gas infrastructure.

Although the states do not appear to be actively pursuing this strategy (because it didn't informally get great reception at FERC and among some stakeholder groups), several states including Massachusetts and Connecticut are exploring the possibility of having retail electric ratepayers (as opposed to wholesale ratepayers) pay for gas pipeline capacity dedicated to electricity-generation. The Maine legislature has already given the Maine PUC authority to purchase (and potentially charge electric and/or natural gas utility ratepayers) for up to 0.2 Bcf/day of gas for consumption in Maine. Similarly, Rhode Island also passed legislation that allows the state to procure incremental natural gas pipeline infrastructure and capacity into New England, and have Rhode Island ratepayers pay for such capacity. On April 27th The MA Depatment of Public utilities opened up a docket on this same issue, posing 25 questions to stakeholders with comments due in May and reply comments in June.

With this as an important backdrop, we explore the key proposals emerging in New England for additional gas infrastructure.

Proposals for Additional Infrastructure

There are currently two relatively small gas pipeline projects that were either approved by FERC or approval is imminent, are generally expected to be built, and were assumed as such in all three of the modeling and analyses mentioned above. The gas from these projects would primarily be used to increase supply for end use customers and not for electricity generation.

1. **AIM Project**—This is an expansion of the existing Algonquin Pipeline owned by Spectra to deliver an additional 0.3 Bcf/day to six utilities/cities for end use customers. It includes some modifications/additions in Boston, and it received its FERC certification in March 3, 2015 and is expected to go in service in 2016. (Note: This project goes through West Roxbury near an active quarry—and Boston Mayor Walsh and others recently filed a petition at FERC for a rehearing.]

2. **Connecticut Expansion Project**—This is an expansion of the existing Tennessee Pipeline owned by Kinder Morgan to deliver an additional 0.07 Bcf/day to two Connecticut Utilities. Expected to be in service in 2016.

There are two potentially much larger projects that are being proposed with an eye to having some to most of the pipeline capacity intended to supply gas-fired electric generation.

3. **Northeast Energy Direct (NED) Project—**This would be a new west to east pipeline proposed by Kinder Morgan owner of the Tennessee Gas Pipeline into New England that would come from New York into western Massachusetts and southwestern New Hampshire. It would be scalable to 2.2 Bcf/day. Currently, Kinder Morgan has announced commitments of approximately 0.5 Bcf/day from nine local gas distribution companies for their end use customers. (No gas generators have committed as of yet to this or any other proposed project.) This pipeline is primarily a greenfield project (i.e., not expansion of existing pipe), and has engendered local controversy in Western Massachusetts. Kinder Morgan recently proposed a substantial re-routing of the project with most of the pipe now routed through existing rights of way and also into Southern New Hampshire (see map below of new route). Kinder Morgan is proposing to file for FERC approval in September 2015, with a proposed in-service date of 2018.

4. **Access Northeast Project—**This would be a further expansion of the existing Algonquin and Maritimes pipeline system (that runs north/south in New England) and is being proposed by Spectra in partnership with Eversource and National Grid. Their proposal is to provide up to 1 Bcf/day that is primarily dedicated to providing gas for power generators. The existing pipeline is in close proximity to approximately 70% of New England's existing gas-fired generators (see map below), and they estimate this gas could support 5,000 MW of power generation. This has not been filed at FERC yet, but proposed in-service date is also 2018.

Figure 29. Northeast Direct (aka NED) pipeline

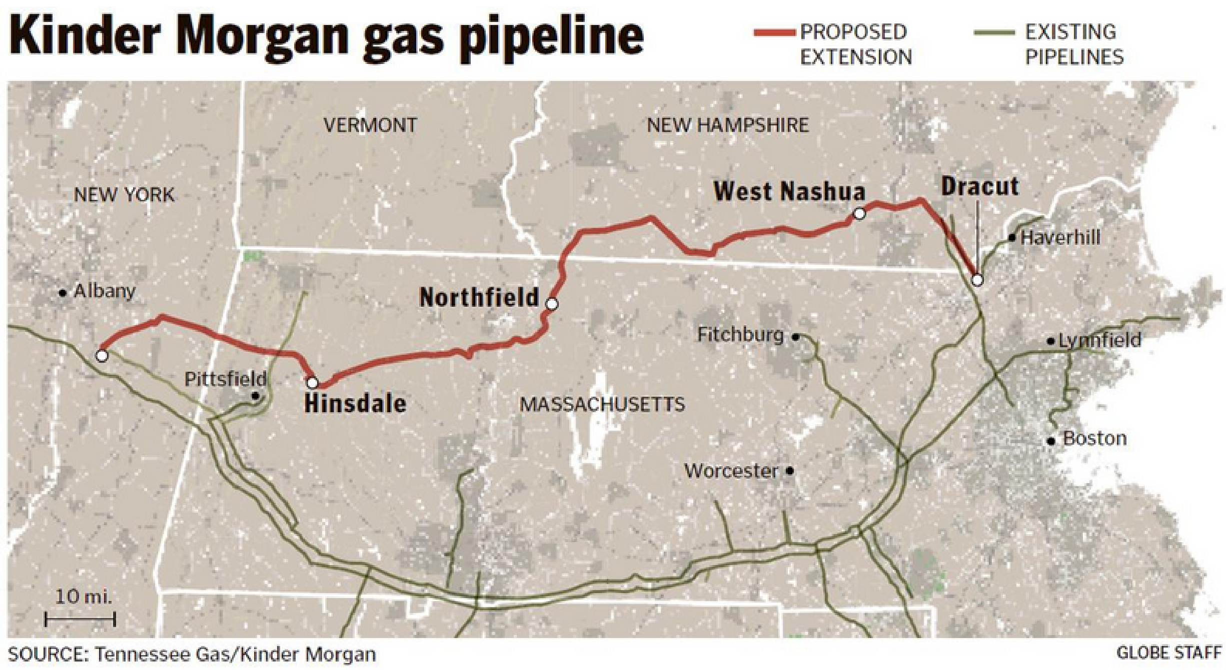
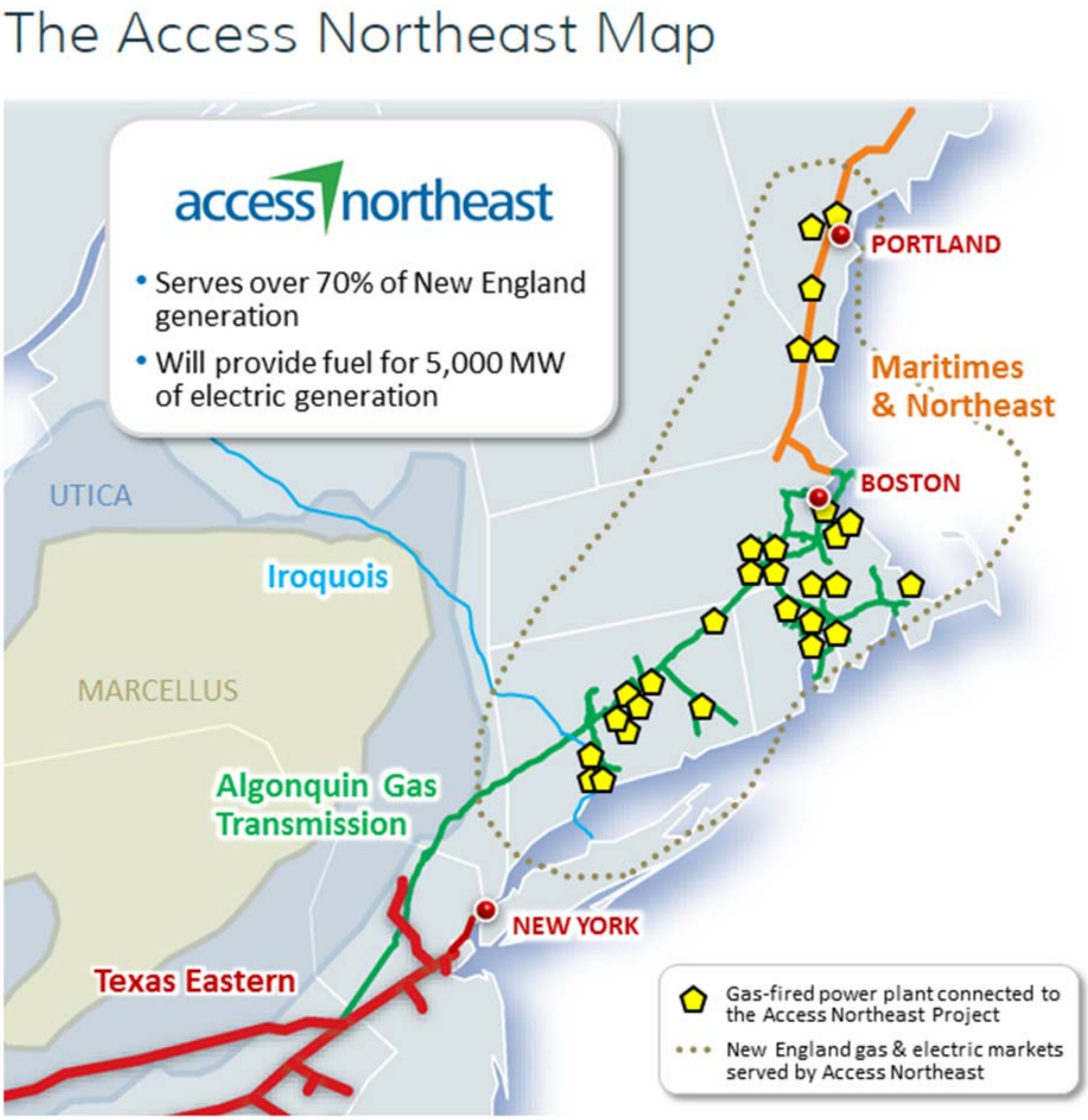


Figure 30. Access Northeast Project pipeline



Both the NED and Access Northeast projects are advocating for New England states to allow electric distribution companies to sign long-term contracts for gas dedicated to power generation. It's not clear whether either project will go forward without this, although NED already apparently has 0.5 Bcf of firm contracts with gas distribution companies. It's also not clear whether there would be sufficient incremental gas demand for heating and electricity-generation to support both projects in full (potentially an additional 2-3 Bcf/day combined).

In addition to local land use concerns especially with the NED project, environmental groups and others are very concerned about the effect that increasing reliance on natural gas will have on the region's ability to meet its greenhouse gas reductions goals. They argue that increasing gas supplies into New

England will supress natural gas and electricity prices, making energy efficiency and renewable energy resources less cost effective. Instead, these stakeholder groups continue to advocate for ramping up distributed energy resources and utility-scale renewables, and using LNG to deal with short-term peak problems rather than locking the region into additional gas pipeline infrastructure and long-term gas contracts for many years.

4. IMPLICATIONS FOR BOSTON

4.1. Electricity Transmission

ISO New England has expressed ongoing concerns about its ability to provide reliable electric service to the Greater Boston area, given increasing electricity demand (due to sharply increased commercial and residential development), current and projected local generation retirements, and limited transmission access into the region. These concerns should largely be alleviated with the construction of a $740 million AC transmission line into the Greater Boston by Eversource and National Grid (recently selected by ISO New England and slated for operation by April 2018) along with the redevelopment at the Salem Harbor power plant site with a new 640 MW quick-start gas-fired generator by Footprint Power (slated to be in-service by 2017), as well as continued aggressive energy efficiency and combined heat and power development in Boston.

Boston also has an important stake in regional discussions about building large transmission projects to bring low-carbon resources such as hydro and wind to help meet greenhouse gas (GHG) goals, and Renewable Portfolio Standards (for wind but not existing hydro in Massachusetts). With Cape Wind likely sidelined indefinitely, those resources will most likely come from northern New England, particularly Maine (wind) and Eastern Canada (hydro). While Boston's recent Climate Plan doesn't rely heavily on those clean energy imports to meet its goal of 25% GHG reduction by 2020, they represent around one fifth of the total reductions needed (in all sectors) in order to reduce the State of Massachusetts' GHG emissions by 2020.

Nonetheless, the proposed Northern Pass project, which would bring 1,200 MW of hydro resources from Quebec to southern New England, has been plagued by local siting opposition in New Hampshire. Meanwhile, other large transmission projects that could bring hydro from the Maritimes and pick up wind resouces in Maine—to be delivered by transmission overland or under the sea--are being formulated by developers and transmission companies. The forthcoming sourthern New England States' RFP for renewables will likely help to accelerate some of these projects. Large transmission projects bringing low-carbon resources from the North could not only help Boston meet its GHG goals in 2020 and beyond, but could help stabilize - if not reduce - regional electricity prices as well as the amount of gas infrastructure and gas supply needed in the region over the long-term.

4.2. Gas Pipelines

From a reliability perspective, constraints to gas pipeline and supply in New England, in combination with a lack of firm gas contracts by gas-fired power generation, is of great concern to ISO New England and others. Despite success in the two most recent winters with oil and LNG resources filling the gap, constrained gas supplies will persist for at least several more winters. Even if reliability is maintained, there is great concern about the high electricity prices in the winter months due to constaints on low-priced pipeline gas for power generation. Nevertheless, the construction of additional gas pipelines has become very controversial in New England for a variety of reasons. FERC's recent approval of a relatively small gas pipeline expansion, the AIM project, which would increase gas deliverability into the Boston area by .3 Bcf/day is still being challenged by the City of Boston due to safety concerns. Recent studies have also found that the relatively old gas pipeline distribution system in Boston leaks substantial amounts of methane, and state legislation and regulations are being put in place to accelerate replacement of those leaky pipes.

Two large projects are being proposed to address the gas constraint issue in New England—NED and Access Northeast—each capable of bringing in over 1 Bcf/day of new gas supplies to fuel electric generators and to continue to convert oil-heated buildings to gas. But despite the promise of increasing reliability and reducing both regional gas and electricity prices in the short run, these pipelines are very controversial and raise opposition on several fronts -. from concerns about siting (visual impacts, environmental damage, and property values) to concerns that this unprecedented request to have electric ratepayers pick up the tab for a gas pipeline dedicated primarily to electric generation could result in stranded assets for ratepayers down the road if the gas was no longer needed. To explore these ratepayer issues, the Massachusetts DPU opened up a docket on April 27 Another concern is that increased gas supply (and the resultant falling energy prices) will reduce the motivation and cost effectiveness to aggressively pursue energy efficiency and renewable energy resources. An increased gas supply, in combination with any slackening of the pursuit of energy efficiency and renewable energy resouces, could make it difficult to meet long-term greenhouse gas targets. Many posit that more aggressively pursuing other alternatives such as efficiency, renewables, and even LNG supplies could defer indefinitely the need for new major pipelines, despite several recent studies to the contrary.

Given the magnitude of the electricity transmission and gas pipeline investments currently being discussed by the New England Governors (who just met on this very issue in mid-April) and by New England's stakeholders, and their potential impacts on Boston's economy and environmental agenda, it is essential that Boston's business leaders familiarize themselves with the issues and consider weighing in on them at the appropriate venues. In that spirit, we hope that this document serves as a useful guide to these complex but very important and timely issues.

GLOSSARY

Behind the meter generation: Electricity production at a customer's location that is not recorded by the standard utility meter at that location.

Capacity, Energy, Load, and Transmission (CELT) Report: An annual report produced by ISO-NE that provides basic information and forecasts about the New England electric system.

Capacity supply obligation (CSO): The obligation taken on by a participant to supply a specified amount of power (capacity), usually expressed as a megawatt (MW) amount for a specific delivery period or year.

Day-Ahead Schedule: The dispatch schedule that the ISO produces showing the resources that are committed to provide energy and reserves each hour for the next day from midnight to midnight.

Economic Upgrade: A process where an entity proposes a self-funded transmission facilities upgrade that ISO-NE will study and determine the impacts on the existing bulk power facilitates. These are sometimes called merchant projects.

Elective Transmission Upgrade (ETU): A process that provides an entity with an evaluation by the ISO of the transmission system impacts of a specific project that the entity is proposing. ETU requests are given a position in a queue that will determine the order by which the ISO evaluates these requests. An ETU analysis by the ISO may be used to support upgrades for reliability, market efficiency, or economic projects; generator upgrades and public policy upgrades use their own separate processes.

Energy Facilities Siting Board (EFSB): The Massachusetts agency responsible for evaluating the need for a new generation resource or transmission upgrade that will be located in Massachusetts. The EFSB can add specific conditions or requirements before granting approval of the proposed project. Other New England states have similar agencies that evaluate requests for new projects.

Facility Upgrade: A general term used to describe improvements to existing generation, transmission, or distribution facilities.

FERC Order 1000: A nation-wide order that requires planning authorities (transmission providers including ISOs and RTOs) to provide competitive bidding for new transmission facility projects rather than deferring to incumbent utilities. The order also requires a mechanism for evaluating, selecting, and building Public Policy transmission projects that are designed to help achieve public policy goals. The order requires adjacent transmission providers to develop inter-regional mechanisms for evaluating, selecting, and building transmission facilities that will benefit customers in more than one planning authority jurisdiction.

Forward Capacity Auction (FCA): The annual auction in February that uses an administrative process (a demand curve) to select a sufficient quantity of resources to meet the anticipated installed Capacity Requirement for the delivery year beginning June 1, three years into the future. FCA-1 was for the delivery year beginning June 1, 2010; FCA-2 was for the delivery year beginning June 1, 2011; etc. FCA-9 for the delivery year beginning June 1, 2018 was conducted in February 2015.

Forward Capacity Market (FCM): The name for the market rules that govern the qualification, selection, and payment of resources that take on capacity supply obligations. The FCM rules have gone through substantial changes since they were approved by the FERC in 2006.

Generator Interconnection Upgrades: Before a resource can connect to the New England bulk power system administered by ISO-NE, there must be a study to determine the impacts of that resource on the existing grid. At a minimum, the resource owner must pay for the equipment that connects its resource to the system. Often there are additional costs to pay for enhancement of existing facilities to accommodate the new resource.

Henry Hub Gas Price: The price of gas at a specific location in the gas distribution system. Many contracts reference the Henry Hub Gas Price as the commodity purchase price. The cost to deliver the gas from the Henry Hub to another point in the pipeline system (transportation cost) and any other fees are added to the commodity purchase price.

Interconnection Queue: A list of requests for interconnection studies from project developers that the ISO studies in sequence based on the date of the request. For some projects, there are specific milestones that must be met to maintain a queue position and avoid going to the bottom of the list.

Interruptible Contracts: Although they vary substantially from state to state and the terms of each contract are often unique, the general format is a contract for a reduced electricity rate in exchange for an agreement to be interrupted for a pre-determined number of hours and days each year. Some contracts specify interruptions in particular seasons (winter or summer) while others are year-round.

Liquefied Natural Gas (LNG): Natural gas that is concentrated (liquefied) for transport purposes and then vaporized before burning it or injecting it into a gas pipeline. LNG can be transported by ship or truck.

Load Center: Usually an urban area where there is a concentration of demand for electricity.

Load Variability: A term to describe the electrical demand from a single customer that varies over a daily or weekly basis. Also used to describe overall changes to electrical demand on either a daily, weekly, or seasonal basis.

Local Network Service (LNS): All electric facilities that do not qualify as regional network service (RNS) facilities are classified as local. The customers of the local distribution utility are responsible for the construction and maintenance of LNS facilities and the cost are collected through the distribution utility's LNS rate as approved by the FERC.

Market Efficiency Transmission Upgrades (METU): ISO-NE studies proposals from stakeholders to determine if specific upgrades to transmission facilities can provide market efficiency benefits (lower costs) that would more than pay for the upgrades. If an METU is determined to be cost-effective, the ISO can authorize the construction of the METU and allocate the costs to those customers that would reap the benefit of the METU (the beneficiaries).

Market Resource Alternative (MRA): A phrase used by ISO-NE to describe alternatives to traditional transmission facility upgrades. In its transmission planning process, the ISO does MRA analyses to establish the MWs of new resources (generation or demand) that would make a proposed transmission upgrade unnecessary. Also referred to as non-transmission alternatives.

Net Passive Demand Resources: The term used by ISO-NE to describe adjustments to load forecasts (and other load analyses) to account for the impact of energy efficiency measures. The energy efficiency measures (passive demand resources) are subtracted (netted) from the load forecast or other value to produce a net reduction to that value.

Non-Transmission Alternative (NTA): A phrase used to describe alternatives to traditional transmission upgrades such as demand resources, renewable resources, and distributed generation resources. Also referred to a market resource alternatives.

Pay-for-Performance (PFP): A revision to the Forward Capacity Market for New England that will penalize resources that do deliver their capacity supply obligation during a shortage condition (reserves are activated) and share those penalties with resources that perform above their capacity supply obligation. PFP becomes effective in the 2018-2019 delivery year (FCA-9).

Public Policy Transmission Upgrade: A component of FERC Order 1000 that requires transmission planning authorities to develop a process for identifying, evaluating, and building transmission upgrades needed to meet public policy goals.

Reliability Credits: The owners of specific transmission lines that connect to power systems outside of New England are given a reliability credit (MW) commensurate with the available transfer capacity of the line. These are also called "tie benefits".

Reliability Criteria Violations: These are violations of thermal capacity, short circuit issues, and voltage levels as established by the North American Electric Reliability Council (NERC), Northeast Power Coordinating Committee (NPCC), and ISO New England.

Reliability Transmission Upgrade (RTU): ISO-NE evaluates the New England transmission grid on a ten-year horizon to determine if there are reliability criteria violations. If violations are found, a transmission upgrade solution is developed to remedy the violations and the costs are assigned to all New England customers.

Regional Network Service (RNS): Electric facilities that provide transmission service in New England are eligible for regional cost recovery through the RNS rate as approved by the FERC. The construction and maintenance costs of RNS facilities are socialized among all New England customers on a pro-rata basis determined by their share of peak load.

Regional System Plan (RSP): An annual report (each September) written by ISO-NE that provides an overview of the New England bulk power system (electric grid) and issues likely to affect the grid in the future. The annual RSP is approved by the ISO Board of Directors in October of each year.

Tie-benefits: (see **Reliability Credits**)

Transmission Cost Allocation Determination Letter: A letter written by ISO-NE after a transmission upgrade has gone into service that (1) confirms that the project was built according to industry practice standards and (2) establishes how much of the costs are assigned to the regional (RNS) rate and how much are assigned to the local (LNS) rate.

Transmission Planning Authority: An owner of transmission, and ISO/RTOs, are required to conduct planning exercises according to a specific FERC-approved process for each entity. The most recent FERC requirements are in Order 1000, which also summarizes earlier FERC requirements in Orders 888 and 889.

Winter Reliability Program: A program that compensates resources for unburned fuel that they purchased as an insurance policy for ISO dispatch on cold winter days. If the fuel is burned, the resource gets the clearing price; if the fuel is not burned, the resource can be compensated for the carrying costs of the unburned fuel. The program was initiated for winter 2013-2014 and is expected to continue through winter 2017-2018.

APPENDIX A: WINTER RELIABILITY

ISO New England raised concerns about gas-fired generation units declaring themselves unavailable during winter months due to their inability to procure pipeline gas on short notice during the winter of 2011-2012 and again in 2012-2013. The ISO's long-term solution was to implement changes to the Forward Capacity Market to make generation units with capacity supply obligations more financially at risk for failure to perform. That solution, however, would not become effective until the 2018-2019 power year. For the interim winters, ISO proposed a Winter Reliability program that would initially focus on dual-fuel (gas and oil) generation units. A small quantity of demand response resources were also solicited by the ISO.

For Winter 2013-2014, The ISO accepted offers from owners of dual-fuel units for specific quantities of oil they would have available beginning December 1, 2013. In total, the ISO accepted slightly over 3 million barrels of oil into the program. The ISO would compensate the generation owners for any unburned oil after February at a pre-determined price to cover their carrying costs for the unburned oil.

During the winter of 2013-2014, over 2.7 million barrels of oil were burned much of it in-merit due to the high gas prices on cold days. At the end of February, dual-fuel units still had 1.8 million barrels of oil in inventory due to replenishments of supply during the winter. The total cost of the program was approximately $64 million.

For Winter 2014-2015, the ISO expanded the program to include commitments to purchase LNG in advance in addition to the oil purchases and demand response commitments. All quantities of LNG and demand response were converted to oil equivalents for payment. In total, the ISO committed to 3.8 million barrels of oil, 500,000 MMBTU of LN, and 14 MW of demand response. The maximum cost exposure to the ISO (if none of the resources were used) was just over $70 million.

During the winter of 2014-2015, just over 2.7 million barrels of oil were burned (almost all in merit order in the daily cleared dispatch). At the end of the winter program, the total cost of the unused oil was just over $43 million. None of the inventoried LNG was used, so the full $1.4 million was paid for the unused inventory. Adding the 14 MW of demand response that was only called once, the total program cost was a little over $46 million.

The two winter programs achieved their primary goal to maintain reliable electric service at a relatively modest cost, often referred to as an insurance policy. Table D-1 summarizes the costs of the insurance policy. However, the overall cost of electric service increased significantly in both winters due to high natural gas prices.

Figure A-1. Winter reliability programs in ISO-NE during last two winters

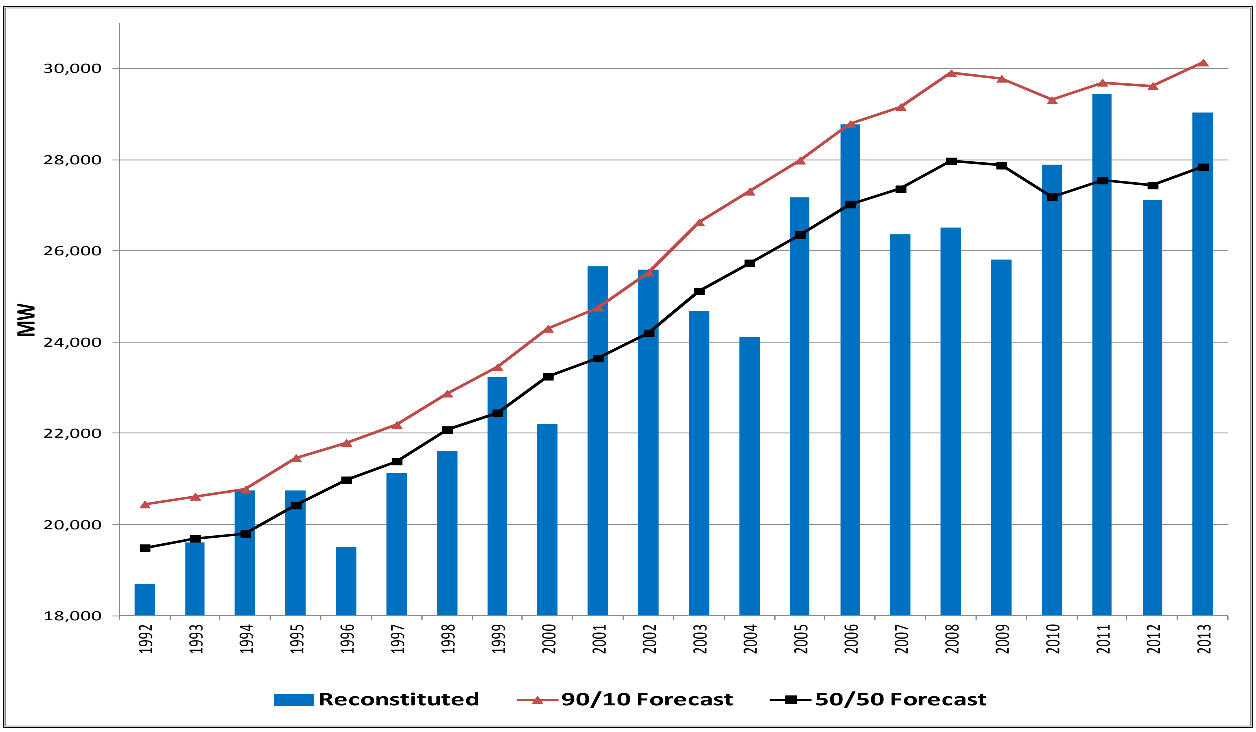
Program by year	Quantity Pledged	Potential Cost	Quantity Burned	Actual Cost
2013-2014				
Oil + Demand Response	3.1 million barrels	$75 million	2.7 million barrels*	$66 million
2014-2015				
Oil	3.8 million barrels	$68.7 million	2.7 million barrels*	$43.9 million
Liquid Natural Gas	500,000 MMBTU	$1.5 million	None	$1.4 million
Demand Response	14 MW	$75,600	One event	$167,190

Note: In both winters, some units replenished their oil supplies during the winter. For 2014-2015, there were approximately one million barrels of replenishment.

APPENDIX B: LOAD FORECASTING

Of particular significance to ISO New England is the relationship between peak loads and extreme weather events. The ISO does its reliability tests for planning purposes based on extreme weather assumptions. Extreme weather scenarios are based on a 90-10 peak load probability analysis. This contrasts with the 50-50 peak load probability analysis that ISO New England uses to determine the annual installed capacity requirement (IC R). Stated simply, the 50-50 peak load values are based on a 50% chance that the peak load value for a summer day will be exceeded; the 90-10 peak load values are based on a 10% chance that the peak load value will be exceeded. The 90-10 peak load values help define the quantity of peak load and reserves that will be necessary to ensure that an involuntary loss of load event occurs no more often than one day in ten years. The “one-day-in ten-years” planning standard has been an industry standard in effect for decades on both a regional and national level.

Figure B-1. The ISO’s actual summer peak loads (i.e., reconstituted for OP 4 and FCM passive demand resources) and the 50/50 and 90/10 forecasts, 1992 to 2013 (MW).

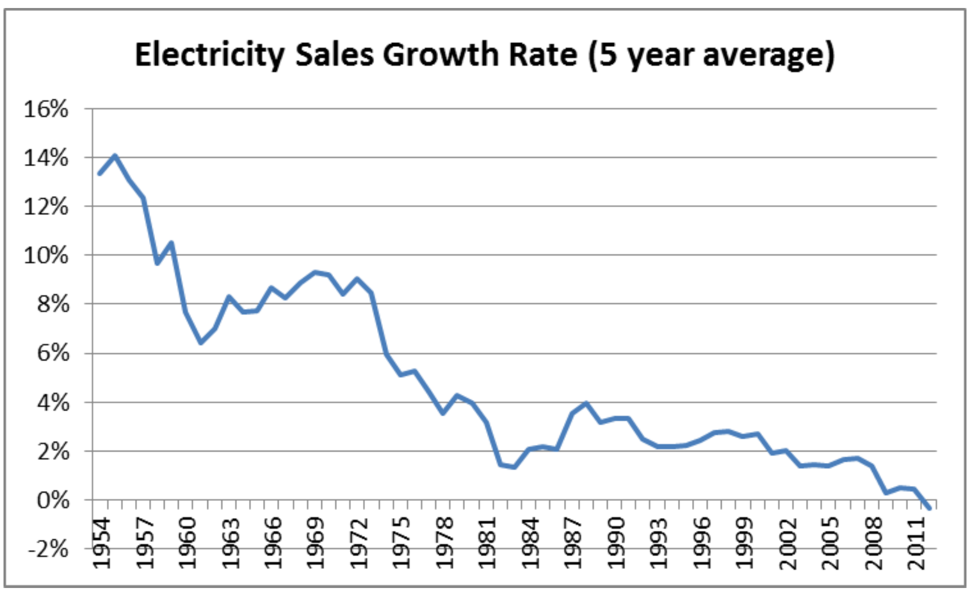


ISO New England 2014 Regional System Plan, Figure 3-1.

As shown in Figure B-1, since 1992, the region exceeded the 90-10 planning standard in only one year (summer 2001) while the 50-50 planning standard was met or exceeded in 11 of the 23 summer years shown. There are some important factors in this figure. While the title says “actual peak loads” these are not the actual system peaks recorded during the summer; the phrase “actual peak” is used to distinguish from weather-normalized peak values. The values in the figure for each summer have been increased to show what the peak load would have been in the absence of energy efficiency resources and OP-4 actions. Energy efficiency resources, since 2007, have been explicitly purchased as a component of the Forward Capacity Market (FCM) annual auctions. The true actual peaks as recorded by the ISO metering system do not account for the efficiency reductions that occur on summer days. To correctly reflect these EE reductions, the ISO adds back the EE resources that are included in the annual FCM auctions to reconstitute the load. The quantity of EE resources purchased in the annual FCM auctions has been steadily increasing so this adjustment to peak loads for energy efficiency resources has become more significant in recent years. The OP-4 adjustments are additional increases to the true actual peak loads that reflect ISO actions pursuant to Operating Procedure 4. OP-4 actions are initiated when the ISO is concerned that peak loads on the system may exceed the resources available to meet those loads. There are a dozen different steps that the ISO can take that include the activation of demand response resources, reduction of reserves (to provide more energy), voltage reductions, and the cutting of exports to other regions. Each OP-4 action has a MW value that can be calculated and these values are added back to the actual meter-recorded peaks (along with the EE adjustments) to produce the reconstituted peak load values in the figure above.

Figure B-2 shows the declining rate of growth from 1950 to present. The rate of growth for electricity consumption has significant consequences for system planning.

Figure B-2. Trends in New England annual energy growth.



Synapse graph from EIA data, 2015.

When the growth rate was 6% annually, electricity consumption would double in less than 12 years. Infrastructure improvements to accommodate increased consumptions might take 5-10 years to plan, approve, and build. There was a sense of urgency to identify the need for new facilities. If a ten-year forecast was over-stated, the growth rate would quickly obscure the error. When the growth rate slowed to 3% annually, electricity consumption would double in 23 years, a more comfortable time-frame to plan, approve, and build new facilities. With today's growth rates of 1% or less, the time horizon for doubling electricity consumption is 70 years. Over-stated forecasts are now a serious problem if they lead to the premature construction of facilities before the growth actually occurs this problem becomes more acute if growth rates turn negative (as has happened to New England energy growth while peak demand growth is still positive), see Figure 1 in the Introduction.

ISO New England faces a serious challenge to account for the changing economic conditions and technology options (energy efficiency measures and distributed generation such as PV) that make planning both more difficult and more necessary than ever before.

These observations about peak loads and the various ways they can be represented are critical to understand in order to participate effectively in discussion of regional energy issue and priorities. ISO-NE and others will often present analyses that do not clearly distinguish between these different representations.

APPENDIX C: MASSACHUSETTS ENERGY FACILITIES SITING BOARD

Note: The following was excerpted from a larger report: Multi-State Energy Facility Siting Review by Raab Associates, CBI, and Rubin & Rudman for the state of New Hampshire as part of a larger project for New Hampshire on reforming their energy facility siting process. Full report can be found here: **http://www.nh.gov/oep/energy/programs/sb99.htm.**

Structure and Authority

Massachusetts

Proposed power plants exceeding 100 MW of generating capacity and new transmission lines greater than 69kV and longer than 1 mile, if in a new transmission corridor, and transmission lines that are greater than 115 kV and longer than 10 miles if located in existing transmission corridor, require the approval of the Massachusetts Energy Facilities Siting Board. Applications for generation facilities should address the effects of the proposed facility upon the environment and provide evidence that the plant will not exceed certain ratios of air pollutant emissions to MW generated. The scope of review for transmission lines encompasses the need for, cost of and alternatives to the transmission line, and a comparison of potential routes, as well as environmental issues.

The petition process in the state of Massachusetts follows an administrative law structure. After an application is filed, public hearings are held. These hearings are followed by an intervention period, a discovery period, and evidentiary hearings. The Siting Board acts as a fact finder, and approves, approves with conditions, or rejects a proposed project based on the evidence developed during the proceedings.

Developers must file an environmental notification form with the Massachusetts Executive Office of Energy and Environmental Affairs. For larger facilities, more detailed Draft and Final Environmental Reports must be filed. An air permit must be obtained from the Massachusetts Department of Environmental Protection; other federal, state, and local permits may also be required.

Membership

9 members (6 public officials from 5 agencies & 3 public members)	The 6 public officials are (or are designated by): Sec. of Energy and Environmental Affairs; Sec. of Housing and Economic Development; Commissioner of the Department of Environmental Protection; Commissioner of the Division of Energy Resources; two Commissioners from the Dept. of Public Utilities. 3 public members are appointed by the Governor.

Staffing

11 members of Dept. of Public Utilities Siting Division serve as staff to the Siting Board.

Application Fee

Non-utility applicants pay a $75,000 fee for the construction of one electrical facility, $100,000 for a combined application in which another non-generating facility will also be constructed, and $125,000 for the construction of two non-generating facilities. Permits for separately filed non-generating facilities cost $75,000 each but fees can be lowered to no less than $25,000 for smaller facilities upon petition. Note: Utilities do not pay fees as they already are assessed annually by the Dept. of Public Utilities.[11]

Covered Facilities

Generation: > 100 MW	Transmission: >115 kV and 10 miles within existing transmission corridor; > 69 kV and 1 miles outside of existing transmission corridor Pipelines: > 1 mile and 100 psi	Renewables: >100 MW

Proposed power plants exceeding 100 MW of generating capacity and new transmission lines greater than 69kV and longer than 1 mile, if in a new transmission corridor, and transmission lines that are greater than 115 kV and longer than 10 miles if located in existing transmission corridor, require the approval of the Massachusetts Energy Facilities Siting Board.[12] Smaller facilities are not permitted to opt in.

The following types of facilities are excluded pursuant to EFSB regulations:[13]

- Reconductoring or rebuilding of an existing transmission line at the same voltage;
- Modification or replacement of equipment at or within a generating plant site that does not increase the gross capacity at such site by more than 10 percent;
- Changes or alterations to a transmission line which do not significantly affect its general physical characteristics, including conversion to a higher voltage;
- Temporary generating or substation facilities;
- Emergency facilities;
- Certain gas manufacturing or storage facilities, as follows --
    - a unit with a total gas storage capacity of less than 25,000 gallons and also with a manufacturing capability of less than 2,000 MMBtu per day;

[11] Massachusetts General Laws, Fees for Applications to Construct Electricity Facilities.

[12] Edison Electric Institute, State Generation & Transmission Siting Directory, 2012, 59.

[13] Code of Massachusetts Regulations, sec. 1.01, 7.04(9), 7.07(8).

- a unit whose primary purpose is research, development, or demonstration of technology and whose sale of gas, if any, is incidental to that primary purpose; or
    - a landfill or sewage treatment plant.
- Construction of a pipeline which for at least the first two years will be used at a pressure less than 100 psi gauge.

Process

Affected parties, including the Attorney General and municipalities, can request to become intervenors to have a greater say in the role in the decision. Throughout the review process, the board provides no financial, technical, or legal support for intervenors or the public, though general guidance is provided to all parties. Unless provided with an exemption, intervenors must be represented by an attorney.[14]

A petition to construct a generating facility requires:[15]

1. A description of the proposed facility, site and surrounding areas, including any ancillary structures and related facilities
2. A description of the environmental impacts and the costs associated with the mitigation, control, or reduction of the environmental impacts of the proposed generating facility;
3. A description of the project development and site selection process used to choose the design and location of the proposed facility;
4. Either evidence of compliance with agency's technology performance standards, or a comparison of the proposed technology and other fossil fuel technologies with respect to environmental impacts, costs and reliability.

Petitions for construction of transmission lines and gas pipelines generally must include an analysis of the need for the facility, costs associated with facilities, and information regarding both route selection and an alternative.[16]

Deadlines

There is a 12-month timeline specified in the statute for Energy Facilities Siting Board cases, but there are no penalties or 'constructive approval' for non-compliance. [17] There is no expedited process,

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[14] Energy Facilities Siting Board, "FAQ's."

[15] Commonwealth of Massachusetts, Massachusetts General Laws, Chapter 164, sec. 69J¼.

[16] Ibid., sec. 69J.

[17] Vermont Energy Generation Siting Policy Commission, "Siting Electric Generation in Vermont - Final Report - Energy Generation Siting Policy Commission," 88.

although the filing fee statute indicates the EFSB will endeavor to complete reviews of applications filed by non-utility entities within 7 months of the last public informational hearing, and utility petitions within 12 months of the last public hearing. In the event of rejection or conditioned approval, the applicant may within six months submit an amended petition. A public hearing on the amended petition shall be held on the same terms and conditions applicable to the original petition. However, there are no penalties if this deadline is missed. The Certificate of Environmental Impact review has a 180-day timeframe.[18]

In Massachusetts there is very active public participation. The board sends notice of filing and public hearing to neighbors, legislators, and officials and publishes information in local newspapers. The board also holds a public hearing in the municipality where the project is proposed. The board allows the public to make comments at these hearings, and also allows for written comments.[19] Project proponents listen to the public and can improve designs over the course of the EFSB review. The general public participates in public hearings that are held at the beginning of the proceeding in the project vicinity; they can offer comments for the record. Special outreach efforts are made for Environmental Justice communities per state policy. Individuals and groups can also participate as 'limited participants' or 'full intervenors.' Cities/towns or RCs typically seek and are granted intervenor status. (Intervenors are not provided with any financial, legal or technical support for their cases but are allowed a greater say in the decision-making process than the general public.) The EFSB provides general guidance to all parties.[20]

After evidentiary hearings, the Board staff prepares an Issues Memorandum identifying contested issues among the parties or potential conditions for the construction or operation of the facility.[21] Conditions stem from the general facility criteria and are laid out on a case-by-case basis depending on the evidentiary record.

Monitoring and enforcement

The EFSB is authorized to levy a civil penalty when an applicant has violated any order of the Board.[22] The maximum fine is $1,000 per day per violation, with a maximum civil penalty of $200,000 for any related series of violations. Post-decision site visits and inspections are infrequent; there is no specific budget for enforcement. The project owner/operator is required to notify the ESFB when the project fails to meet conditions specified in the approval decision or if there are any changes "other than minor variations" to the proposal approved by the Siting Board. Complaints from local officials or

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[18] "An Introduction to Massachusetts Generation Facility Siting Considerations," 3.

[19] Vermont Energy Generation Siting Policy Commission, "Siting Electric Generation in Vermont - Final Report - Energy Generation Siting Policy Commission," 90.

[20] Ibid.

[21] Energy Facilities Siting Board, "FAQ's."

[22] 188th General Court of the Commonwealth of Massachusetts, Title 22, Corporations, Manufacture and Sale of Gas and Electricity, 22.

members of the public are sometimes a means by which non-compliance with EFSB conditions is identified and enforced.[23]

Decisionmaking process

The Siting Board staff issues a Tentative Decision approving or rejecting the project. The parties receive the Tentative Decision prior to the scheduled Siting Board meeting for review and comment. After the comment period, the Siting Board meets in public to vote on whether to accept the Tentative Decision. The Final Decision reflects any changes made at the Siting Board meeting.[24]

Within 60 days of the filing of a petition to construct a generating facility, the board shall conduct a public hearing in each locality in which the generating facility would be located. In addition, the board shall, within 180 days of the filing thereof, conduct public evidentiary hearings on every petition to construct a generating facility. Evidentiary hearings for both oil and generating facilities are adjudicatory proceedings under the provisions of chapter 30A.

For either oil or generating facility, if the board determines the standards set forth have not been met, it shall within twelve months of the date of filing reject in whole or in part the petition, setting forth in writing its reasons for such rejections, or approve the petition subject to stated conditions. In the event of rejection or conditioned approval, the applicant may within six months submit an amended petition. A public hearing on the amended petition shall be held on the same terms and conditions applicable to the original petition.

Appeals of EFSB or DPU decisions are made directly to the Supreme Judicial Court.[25]

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[23] Vermont Energy Generation Siting Policy Commission, "Siting Electric Generation in Vermont - Final Report - Energy Generation Siting Policy Commission," 33 & 92.

[24] Energy Facilities Siting Board, "FAQ's."

[25] Vermont Energy Generation Siting Policy Commission, "Siting Electric Generation in Vermont - Final Report - Energy Generation Siting Policy Commission," 33.

Criteria for decsionmaking

The board shall, within one year from the date of filing, approve a petition to construct a generating facility if the board determines that the petition meets the following requirements:

1. The description of the proposed generating facility and its environmental impacts are substantially accurate and complete;
2. The description of the site selection process used is accurate; and
3. The plans for the construction of the proposed generating facility are consistent with current health and environmental protection policies of the commonwealth and with such energy policies as are adopted by the commonwealth for the specific purpose of guiding the decisions of the board;
4. Such plans minimize the environmental impacts consistent with the minimization of costs associated with the mitigation, control, and reduction of the environmental impacts of the proposed generating facility; and
5. If the petitioner was required to provide information on other fossil fuel generating technologies, the construction of the proposed generating facility on balance contributes to a reliable, low-cost, diverse, regional energy supply with minimal environmental impacts.

Visual Impacts: The Siting Board considers visual impacts and mitigation of these impacts for both a preferred and alternative route in its reviews of proposed transmission lines (*see National Grid/Western Massachusetts Electric Company*, EFSB 10-1/D.P.U. 10-107/108 (2012) at 52-56; *NSTAR Electric Company*, EFSB 10-2/D.P.U. 10-131/132 (2012) at 68-72). The EFSB also has looked at undergrounding alternatives to address both visual and EMF impacts (*see Western Massachusetts Electric Company*, EFSB 08-2/D.P.U. 105-106 (2010) at 66-73, 84-98).

Rights of Way: The EFSB reviews proposed transmission lines 69 kV or more and 1 mile or greater, if in a new transmission corridor, and transmission lines that are 115 kV or more and 10 miles or longer if located in an existing transmission corridor.[26]

The Siting Board considers the cumulative impacts on local and regional health. This may include multiple electric generation plants and other contributors.[27]

For proposals to construct transmission lines or intrastate gas pipelines, EFSB must find that proposed plans are consistent with resource use and development policies of the Commonwealth.[28]

Alternative dispute resolution

No formal ADR although parties are welcome to propose settlements to the EFSB, which is rare. In practice, facility applicants actively engage with host community officials and members of the public to

[26] Edison Electric Institute, State Generation & Transmission Siting Directory, 2012, 59.

[27] Ibid.

[28] Commonwealth of Massachusetts, Massachusetts General Laws, Chapter 164, sec. 69J.

discuss mitigation measures and other agreements that can lead to support or at least lack of active opposition. EFSB approval conditions can formalize agreements and commitments between project proponent and parties. Appeals of EFSB or DPU decisions are made directly to the Supreme Judicial Court.[29]

[29] Vermont Energy Generation Siting Policy Commission, "Siting Electric Generation in Vermont - Final Report - Energy Generation Siting Policy Commission," 33.

APPENDIX D: REGIONAL SYSTEM PLAN PROJECT LIST

Figure D-1 shows a portion of the Regional System Plan (RSP) Project List spreadsheet updated in March 2015. We chose a portion that shows several upgrades for the Eastern Massachusetts region. The link to the entire 40 page spreadsheet is listed below.

The small portion of the Project List spreadsheet in Figure D-1 includes just the first ten columns for each project; later columns show the history for each project for the last several years. The first ten columns identify the type of project (reliability, economic, merchant, etc.), project ID number, state located in, primary equipment owner (transmission company), and projected in-service date. For large projects, many sub-components are listed with each sub-component tracked as a separate project.

Figure D-1. RSP Project List excerpt, March 2015

Primary Driver	Part#	Project ID	State	Primary Equipment Owner	Other Equipment Owner(s)	Footnote Number	Projected In-Service Month/Year	Major Project	Project
Reliability Upgrade	1a	1226	MA	Eversource			2016	Pittsfield / Greenfield Project	Reconductor the Woodland to Pleasant 1371 115 kV line and terminal w ork at Woodland substation.
Reliability Upgrade	1a	1532	MA	Eversource			12/2016	Pittsfield / Greenfield Project	Remove the sag elimination on the 1512 115 kV line from Blandford substation to Granville Junction and also remove the limitation on the 1421 115 kV line from Pleasant to Blandford substation
Reliability Upgrade	1a	1488	MA	National Grid, USA			12/2016	Pittsfield / Greenfield Project	Harriman Station - Breaker replacement and terminal equipment upgrades (Asset Condition)
Reliability Upgrade	1a	1525	MA	National Grid, USA			10/2016	Pittsfield / Greenfield Project	Loop the A127W line betw een Cabot Tap and French King into the new Erving Substation
Reliability Upgrade	1s	1329	MA	National Grid, USA			12/2015	Greater Boston - Western Suburbs	Refurbishment of 69 kV line X-24 Millbury-Northboro Rd
Reliability Upgrade	1a	1489	MA	National Grid, USA			**12/2017**		Sandy Pond Control House Rebuild
Reliability Upgrade	1a	1526	MA	National Grid, USA			8/2017		Sandy Pond Substation refurbishment (Asset Condition)
Reliability Upgrade	1a	1493	MA	National Grid, USA			06/2016	New Highland Park Substation Project	Terminal upgrades at Robinson Ave Substation (V-148S)
Reliability Upgrade	1a	1511	MA	National Grid, USA			8/2015	New Wakefield Municipal Wallace Substation	Reconductor the S-145/T-146 115 kV lines from Wakefield Junction to new Wallace Substation.
Reliability Upgrade	1a	1494	MA	National Grid, USA			**04/2015**	New Centech Substation	Add a new 115/13.8 kV Centech Substation. By looping the E157 W line in and out of this new substation.
Reliability Upgrade	1a	1505	MA	SELCO			**04/2015**	New Centech Substation	Add a new 115/13.8 kV Centech Substation. By looping the E157 W line in and out of this new substation.

Source: ISO New England, Regional System Plan available at http://www.iso-ne.com/static-assets/documents/2015/04/final_rsp15__project_list_march_2015.xls

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