# Table of Contents

- **INTRODUCTION** ............................................................................................................................................................................. 4
- **FROM THE HEADLINES** ................................................................................................................................................................. 6
- **CONTEXT: THE COST OF ENERGY IN NEW ENGLAND** .................................................................................................................... 7
- **SETTING THE AGENDA: NEW ENGLAND GOVERNORS’ 2013 STATEMENT** .................................................................................... 10
- **HISTORY: HOW NEW ENGLAND’S ENERGY MARKETS GOT HERE** ................................................................................................ 11
- **BACKGROUND ON THE NEW ENGLAND POWER GRID** ............................................................................................................. 13
- **MAJOR POWER PLANTS IN NEW ENGLAND** ................................................................................................................................ 14
- **HOW GAS HAS COME TO DOMINATE THE ELECTRIC GRID** ........................................................................................................ 16
- **THE UNPREDICTABLE INTERCONNECTEDNESS OF FUEL-SOURCE CHOICES** ............................................................................... 19
- **HOW NEW ENGLAND GETS NATURAL GAS** ................................................................................................................................. 20
- **NATURAL GAS PIPELINES** ........................................................................................................................................................... 21
- **GAS OUTLOOK: AMPLE SUPPLY, AMPLE DEMAND, CONSTRAINTS** .............................................................................................. 24
- **EXPANDING THE GAS NETWORK: PLANS MOVING, PLANS DROPPED** ......................................................................................... 26
- **SHOULD ELECTRIC CUSTOMERS BE BILLED FOR GAS UPGRADES?** ........................................................................................... 27
- **CT, ME, NH, RI ON ELECTRIC CUSTOMERS PAYING FOR GAS** ...................................................................................................... 30
- **ENVIRONMENTALIST OPPOSITION TO NATURAL GAS** ................................................................................................................ 31
- **HEATING OIL AS A CONTINUING, RELIABLE, GREENER FUEL SOURCE** ........................................................................................ 32
- **NEW ENGLAND’S ENERGY/ENVIRONMENTAL FRAMEWORK: RPS’S, RGGI, AND GLOBAL CLIMATE CHANGE LAWS** ............. 32
- **CONNECTICUT/MASSACHUSETTS/RHODE ISLAND CLEAN ENERGY RFP** .................................................................................... 36
- **WIND POWER WITHIN NEW ENGLAND AND OFF THE COAST** ....................................................................................................... 37
- **RENEWABLE ENERGY PLANS NEED NEW TRANSMISSION** ........................................................................................................ 38
- **OPERATIONAL CHALLENGES OF RENEWABLES IN THE GRID—NOT ALL MEGAWATTS ARE CREATED EQUAL** ...................... 40
- **WHO DECIDES WHAT GETS BUILT, AND HOW? ISO, FERC, STATE REGULATORS, AND INVESTORS’ ROLES** .............................. 42
- **THE FEDERAL ENERGY REGULATORY COMMISSION AND STATES’ ROLES** ................................................................................. 45
- **THE FUTURE OF NUCLEAR POWER IN NEW ENGLAND** ................................................................................................................ 47
- **WHAT ARE “SOLAR NET METERING CAPS” AND WHY ARE THEY SUCH A HOT ISSUE IN SO MANY NEW ENGLAND STATES?** ...... 48
- **DEMAND RESPONSE/ENERGY EFFICIENCY** ................................................................................................................................. 49
- **ENERGY STORAGE AND RENEWABLE ENERGY GROWTH** ............................................................................................................ 51
- **CONCLUSION** ............................................................................................................................................................................. 52
- **UPCOMING DATES** ...................................................................................................................................................................... 56
- **ACKNOWLEDGMENTS** ................................................................................................................................................................. 57
October 2016

NEC Members & Friends:

The New England Council—the nation’s oldest regional business association—is dedicated to promoting economic growth and a high quality of life in the New England region. One of the key ways that the Council works toward this goal is by supporting policies designed to ensure that businesses and organizations throughout the region receive the reliable and cost effective electric power service that is needed to maintain and expand economic growth and employment in the region. The Council firmly believes that the best way to develop policy for New England is through regional collaboration, and through cooperation and communication between the public and private sectors.

The Council prides itself on being a resource to leaders in federal, state, and local government as they seek to develop policy that will address our region’s energy challenges and ensure a reliable energy market for New England. Over the years, we have developed and published a number of reports and briefing papers—often in collaboration with other organizations or issue experts—on a range of important energy issues, including energy supply and demand, LNG supplies, nuclear energy, climate change, and low income energy assistance. Our goal with each of these publications, as with the report that follows, is to provide thorough, reliable, and unbiased information that will help educate and inform decision makers at all levels of government.

The report that follows presents what we believe to be a very comprehensive overview of the history of our region’s electric power market, some of the key challenges we face, and the outlook for the coming years. In the course of developing this document, over 30 stakeholders, including a wide range of energy businesses, as well as industry organizations, were consulted and asked to share information and insights. We are grateful to all of those who contributed to the development of this report and believe that the broad spectrum of sources and perspectives makes this a valuable guide to understanding the current energy landscape in New England.

We hope that our policymakers and other stakeholders will find this report to be a useful resource as continue to work toward our shared goals of ensuring affordable, reliable, and sustainable energy for the New England region.

Best Regards,

James T. Brett
President & CEO
INTRODUCTION

New England’s energy system has reached its most complex crossroads in history. In coming months and years, legislators, regulators, and policymakers will have to make challenging, interrelated, and far-reaching decisions about how the region meets its future power needs and environmental policy mandates, from what energy sources, and at what cost for businesses and consumers across the region.

The decisions don’t amount to picking which one direction to take. Rather, they are decisions about what mix of multiple pathways and approaches should be best combined to ensure the most reliable, affordable energy supply that also meets aggressive goals and mandates in all six states for mitigating pollution and climate impacts over the next three decades. New England has voted through its democratic processes and elected representatives for an energy supply that is affordable, reliable, and environmentally friendly. But in the near term, until some major technological breakthroughs prove workable at large scale and financially viable, trade-offs appear unavoidable—and challenging to quantify—among cost, reliability, and environmental impact.

At the policy level, legislators, regulators—and now judges—are weighing proposals from New England governors to allow electric utilities to have customers pay for more natural gas capacity as a strategy to improve electric and gas supply reliability and lower costs. Also under consideration and taking effect are new proposals and laws to allow those utilities to enter into long-term contracts for renewable energy such as offshore and onshore wind and large-scale hydropower, including big imports from Canada. Power-grid managers are bracing for the imminent planned shutdowns of New England’s biggest coal-fired power plant and yet another nuclear plant, with likely more shutdowns to come, while also preparing for billions of dollars in proposed new energy infrastructure, much of it for renewable energy. States and grid managers are working to improve the finances and mechanics of incorporating more wind power, large- and small-scale solar, and energy storage into the grid, and the most effective ways to promote energy efficiency and targeted conservation and “smart-grid” technology. This is all happening within mandates in all six states to reduce overall carbon-dioxide emissions, with key deadlines coming in just 3 years, and to meet requirements for getting energy from renewable sources.

The New England Council believes it is critical for policymakers to understand that all of these policy decisions are tightly interrelated, even if the connections are not immediately obvious. No one decision—or vote—about New England’s energy future can be made in a vacuum. Like pushing on a balloon, pushing on one side of the energy market in hopes of driving one policy or price goal will make something pop up on the other side of the energy market that impacts other policy and price goals.

Given that natural gas delivered 43 percent of New England’s electric consumption in 2014, and in the workings of the competitive market gas sets the wholesale price 70 percent of the time, according to Independent System Operator (ISO) New England’s 2016 “Regional Energy Outlook,” proposals for increased pipeline capacity to lower the cost of electric generation will change the economics of renewables and nuclear power, as well as of liquefied natural gas delivered by ship to meet peak local needs. Adding large-scale offshore wind and imported Canadian hydropower to the grid would
change the economics for nuclear power and the need for and price of gas. Both sets of decisions have major implications for whether and when the six states meet their 2020 and 2050 goals for reducing greenhouse-gas emissions from electric generation and meeting renewable energy standards. That includes how viable non-carbon-emitting nuclear generation remains, especially after the closure of the four Yankee nuclear plants in Connecticut, Maine, Massachusetts, and Vermont, and the June 2019 planned shutdown of Pilgrim Station in Plymouth. Availability of and prices for natural gas driven by electric demand will also affect demand for and the price of home heating oil and the economics of homeowners and business converting from oil to gas—and also whether some New England utilities can lift moratoria on new gas service because of supply constraints.

The six New England states’ decisions are also profoundly interrelated as a matter of local physical realities. Because of the way the six New England states’ electric networks function as a single unified grid, decisions made in one state capital often mean visible, tangible impacts in other states. A hunger in Massachusetts, Rhode Island, and Connecticut for more renewable energy from hydroelectric or land-based wind sources may well require construction of controversial new and expanded electric transmission lines in Maine, New Hampshire, and Vermont. A hunger in Maine for more natural gas supply to keep manufacturing viable and lower heating costs may well require construction of controversial pipeline upgrades in Massachusetts and Connecticut. And what are essentially political and policy choices about the preferred levels of renewable power, and where and how to site it, will have to be implemented through a regional power-grid management system whose first priority is always reliable service. New England and its energy system managers have only started to work out policies and procedures to accommodate much heavier flows of renewable energy and the operational challenges that the variability of wind and solar energy can create on a grid first built for steadily-running nuclear, coal, and oil plants.

This report aims to offer an impartial, unbiased explanation of the fundamental issues facing policymakers, regulators, and legislators in the New England energy debate. Perhaps the central question in this whole debate: How much can New England trust a free market, with policies that don’t pick winners and losers, will solve problems of high price and supply and meet our emissions and climate-change goals? What intervention by policymakers is required to ensure New England has reliable, affordable energy supplies that also meet the environmental goals and mandates set by governors and legislators as shaped by advocates and stakeholders?

If, as now seems likely, the answer is a mix of free-market forces and policy direction: What’s the right mix? How do we get there? And what changes are needed in the processes and procedures for translating multiple states’ energy and environmental policies into planning and running a single regional power grid and gas supply network?

Beyond that, The New England Council commissioned this report in hopes of helping everyone who depends on the flow of energy—that is to say, everyone in New England—better understand:

• how the electric grid and gas supply network function,

• what determines retail prices,

• and who decides which power plants, pipelines, and transmission lines get built, how, and how stakeholders can get involved in shaping those decisions. 
FROM THE HEADLINES

This report is being published as the news has been filled with major headlines about energy issues in New England so far in 2016:

• Massachusetts, Connecticut, and Rhode Island are jointly moving to acquire more renewable energy, including on- and off-shore wind from throughout New England and hydroelectric power from Quebec and other areas of Canada, through a three-state Request for Proposals that has generated more than 30 initial responses from energy developers. In Massachusetts, Governor Charlie Baker on August 8, 2016, signed legislation that directs the state’s utilities to solicit contracts for 1,600 megawatts of offshore wind generation and 9.45 million megawatt-hours per year of “clean energy,” most likely Canadian hydropower—in all, about 30 to 40 percent of the state’s electric demand.

• Massachusetts’ highest court has ruled illegal under state law a plan to have electric ratepayers billed to pay for more gas capacity intended to reduce electric rates—something Connecticut, Maine, New Hampshire, and Rhode Island have all been considering or moving forward with, but based on an expectation the region’s biggest state would also be helping shoulder the cost of major pipeline upgrades.

• Kinder Morgan’s Tennessee Gas has announced it is abandoning a $3.3 billion pipeline project across Western Massachusetts and New Hampshire amid intense local and regional opposition.

• More than $2 billion worth of other gas pipeline upgrades by Kinder Morgan and Spectra Energy and their partners are well under way, but often facing controversy and lawsuits.

• This past winter, New England avoided a repeat of the dire winter of 2013-14. But the region’s power-grid operators remain deeply concerned that New England may be too reliant on natural gas for producing electricity and could face major reliability problems during a prolonged winter cold snap or gas supply interruption.

• 2020 deadlines in several states for reducing Greenhouse Gas emissions are rapidly approaching, and Massachusetts’ highest court this spring ruled that the state’s Global Warming Solutions Act contains binding limits for 2020 that must be enforced by regulators. Still to be answered is how much electric generation will have to further reduce emissions compared to the transportation or building sectors.

• Owners of the Pilgrim nuclear generating station in Massachusetts announced in the autumn of 2015 that it will close in June 2019. This came soon after Vermont Yankee shut down at the end of 2014. Losing the nuclear plants will make it even harder for New England states to attain their goals and mandates for reducing carbon-dioxide emissions. The trend also aggravates concerns that New England is losing diversity and resiliency in its generation mix—especially if other policies promoting hydroelectricity imports and gas supply increases further challenge the economic viability of nuclear power in New England.

• Huge plans are unfolding for wind power in northern New England and off the coast, supported by billions of dollars in proposed new transmission lines. Many of those projects are being pursued under new approval mechanisms that are still being perfected and that are generating opposition, threats of legal action, and in Vermont new legislation (S. 260) to give local communities more control over siting of energy facilities.
• How to best integrate solar power, demand reduction, energy storage, and other technologies into the grid physically and financially are still major questions policymakers in all six states are addressing.

CONTEXT: THE COST OF ENERGY IN NEW ENGLAND

With no sources of gas, oil, or coal, and little opportunity for additional conventional large-scale hydroelectric power in the region, New England pays markedly higher energy prices relative to the rest of the United States because we are “at the end of the pipeline” for energy supply. This affects the region’s economic competitiveness both for businesses choosing to locate or expand here and for their employees and the energy bills they pay.

For many businesses, especially industrial and manufacturing companies, high energy bills are the number-one challenge to succeeding, growing, and adding jobs in New England. Polar Beverages in Worcester, Massachusetts, for example, also has plants in Scotia, New York, and Fitzgerald, Georgia, where its electric and gas rates are roughly half as expensive as they are in Worcester. Owners of the Madison Paper Industries mill in Maine announced they would close in May 2016 and lay off 214 workers, citing foreign competition but also the high cost of natural gas. The Madison plant had shut down repeatedly in the winter of 2015 because the cost of gas made production unaffordable. Expensive energy often ranks right up with expensive real estate as a top challenge CEOs cite to doing business in New England.

According to January 2016 data from the U.S. Energy Information Administration, the six New England states all rank in the top 10 of U.S. states for the retail price of electricity and of natural gas:

<table>
<thead>
<tr>
<th>State</th>
<th>Electric Price (kWh)</th>
<th>Rank Among 50 States</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>19.86¢</td>
<td>2</td>
</tr>
<tr>
<td>ME</td>
<td>17.66¢</td>
<td>8</td>
</tr>
<tr>
<td>MA</td>
<td>19.34¢</td>
<td>4</td>
</tr>
<tr>
<td>NH</td>
<td>18.00¢</td>
<td>6</td>
</tr>
<tr>
<td>RI</td>
<td>18.41¢</td>
<td>5</td>
</tr>
<tr>
<td>VT</td>
<td>16.62¢</td>
<td>9</td>
</tr>
</tbody>
</table>


Numbers for Nearby/Competitor States:

<table>
<thead>
<tr>
<th>NY</th>
<th>16.54¢</th>
<th>10</th>
<th>NJ</th>
<th>15.45¢</th>
<th>11</th>
</tr>
</thead>
<tbody>
<tr>
<td>MD</td>
<td>14.03¢</td>
<td>13</td>
<td>PA</td>
<td>13.87¢</td>
<td>14</td>
</tr>
<tr>
<td>MN</td>
<td>11.99¢</td>
<td>19</td>
<td>IL</td>
<td>11.42¢</td>
<td>24</td>
</tr>
<tr>
<td>NC</td>
<td>10.44¢</td>
<td>37</td>
<td>WA</td>
<td>9.07¢</td>
<td>47</td>
</tr>
</tbody>
</table>

(eia.gov/state/rankings/#/series/31)
At the same time, analysis by Susan F. Tierney of Analysis Group shows that, broadly speaking, energy costs have become a less severe problem for New England than they were 15 years ago, a change that coincides with a period in which the electric industry has been restructured. Across the region, compared to the rest of the country, every New England state’s rank for gross state product per dollar spent on electricity has improved significantly since 1997. At the same time, while the average residential electric bill as a percentage of median income was above the U.S. average in 1996, by 2015, every New England state was at or below the U.S. average—a way of saying that electric affordability and the cost of electricity as an economic drag has improved in New England compared to the U.S.
And while it is just a one-year change, ISO New England reported in late May that the average wholesale price of electricity in 2015 fell to 4.1 cents per kilowatt-hour from 6.3 cents in 2014, largely because of a 41 percent drop in the cost of natural gas in 2015 (from $7.99 per million BTU’s in 2014 to $4.73 per million BTU’s in 2015). (Multiply MMBTU by 1,000 to get millions of cubic feet.) (Commonwealth Magazine, “Wholesale Electric Prices Fell By Third in 2015”)

Looking out to 2024, ISO New England, which is based in Holyoke, Massachusetts, and runs and plans the six-state power grid and wholesale regional electric markets, does not see any robust increase in demand for electricity that would put more upward pressure on prices. The ISO sees energy efficiency and demand-reduction measures growing much faster than overall demand for electricity in the next decade. In its 2015 Regional System Plan, based on forecasts of GDP growth, conservation, and other factors, the ISO made these projections about the compound annual growth rate in demand for power across the region and in the six states:

<table>
<thead>
<tr>
<th>U.S. State</th>
<th>1996 %</th>
<th>Rank</th>
<th>2015 %</th>
<th>Rank</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>2.3%</td>
<td>25</td>
<td>2.6%</td>
<td>19</td>
</tr>
<tr>
<td>ME</td>
<td>2.2%</td>
<td>32</td>
<td>2.0%</td>
<td>39</td>
</tr>
<tr>
<td>MA</td>
<td>1.9%</td>
<td>43</td>
<td>2.3%</td>
<td>28</td>
</tr>
<tr>
<td>NH</td>
<td>2.3%</td>
<td>28</td>
<td>1.9%</td>
<td>46</td>
</tr>
<tr>
<td>RI</td>
<td>2.0%</td>
<td>42</td>
<td>2.3%</td>
<td>27</td>
</tr>
<tr>
<td>VT</td>
<td>2.2%</td>
<td>33</td>
<td>1.9%</td>
<td>47</td>
</tr>
<tr>
<td>U.S. avg</td>
<td>1.6%</td>
<td></td>
<td>2.6%</td>
<td></td>
</tr>
</tbody>
</table>

Source: The Analysis Group

Photo courtesy of National Grid.
## Setting the Agenda: New England Governors’ 2013 Statement

To a significant extent, the current energy conversation across New England was set up and framed by a joint statement issued by all six New England governors in December 2013, laying out challenges, opportunities, and goals. The statement read in part:

“Securing the future of the New England economy and environment requires strategic investments in our region’s energy resources and infrastructure. These investments will provide affordable, clean, and reliable energy to power our homes and businesses; make our region more competitive by reducing energy costs; attract more investment to the region; and protect our quality of life and environment.”

The governors called for:

- greater integration and utilization of renewable generation;
- development of new natural gas pipeline infrastructure;
- maximizing the use of existing transmission infrastructure; investment, where appropriate, in new transmission infrastructure;
- and continuation of the inclusion of energy efficiency—and the addition of distributed generation—in load forecasting and transmission planning.

And they noted: “As the region’s electric and natural gas systems have become increasingly interdependent, ensuring that we are efficiently using existing resources and securing additional clean energy supplies will be critical to New England’s economic future. To ensure a reliable, affordable and diverse energy system, we need investments in additional energy efficiency, renewable generation,

<table>
<thead>
<tr>
<th>State</th>
<th>CAGR of Net Load</th>
<th>Summer Peak Demand Growth</th>
<th>Winter Peak Demand Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>1.0%</td>
<td>1.3</td>
<td>0.7</td>
</tr>
<tr>
<td>CT</td>
<td>1.0%</td>
<td>1.0</td>
<td>0.5</td>
</tr>
<tr>
<td>ME</td>
<td>0.8%</td>
<td>0.9</td>
<td>0.4</td>
</tr>
<tr>
<td>MA</td>
<td>1.2%</td>
<td>1.5</td>
<td>0.8</td>
</tr>
<tr>
<td>NH</td>
<td>1.1%</td>
<td>1.6</td>
<td>0.8</td>
</tr>
<tr>
<td>RI</td>
<td>0.7%</td>
<td>1.3</td>
<td>0.5</td>
</tr>
<tr>
<td>VT</td>
<td>0.7%</td>
<td>0.9</td>
<td>0.7</td>
</tr>
</tbody>
</table>

Source: ISO New England, 2015 Regional System Plan, page 34
natural gas pipelines, and electric transmission. These investments will also serve to balance intermittent generation, reduce peak demand, and displace some of the least efficient and most polluting fossil fuel generation, enabling the states to meet clean energy and greenhouse gas reduction goals while improving the economic competitiveness of our region. New England ratepayers can benefit if the states collaborate to advance our common goals.”

Everything the governors outlined in their 2013 statement and in follow-up statements through the Coalition of Northeastern Governors has framed the agenda and discussions now playing out in Augusta, Boston, Concord, Hartford, Montpelier, and Providence; in Washington, D.C., and before the Federal Energy Regulatory Commission; and in the planning processes overseen by ISO-New England with all the stakeholders and advocacy groups who participate in the ISO’s processes.

HISTORY: HOW NEW ENGLAND’S ENERGY MARKETS GOT HERE

Most New England states deregulated, or “restructured,” their electric markets in the 1990s with the hope of using competitive forces and choice to lower costs and increase choice and innovation. At that point, America had seen deregulation of the airline, telecommunications, railroad, trucking, and oil and gas industries lower costs and spur new services and products. Electricity was, by overall expenditure, one of the largest remaining markets in which prices and supplies were still set by regulators and utility policymakers, not markets.

The main principle of electric restructuring was to get utilities out of being “vertically integrated” energy companies that controlled retail energy, transmission, and power generation, and instead transform them into “pipes and wires” companies delivering energy that customers bought from independent suppliers who would compete to offer the lowest price. Simplistically, the goal resembled what happened with the breakup of AT&T: Consumers kept a local monopoly regulated company for their dial tone and local service, and were newly free to shop for the best priced “long distance” service and other telecom products from multiple competing providers. From 1995 to 1998, legislators in every New England state except Vermont voted to adopt a version of restructuring. Utilities such as Boston Edison, Central Maine Power, Massachusetts Electric, Northeast Utilities, and Public Service of New Hampshire were required to sell off their directly managed power plants and their ownership stakes in power plants to competitive generating companies. “Stranded costs” of paying off the debt on power plants that couldn’t be sold for anything close to what utilities had paid to build them were passed along to consumers through “transition charges,” on the theory that after a limited time, consumers would be paying enough less for electricity to realize net savings and net benefits from restructuring. Gas utilities were envisioned to be restructured in the same way as electric utilities in time, but after early turmoil with electric markets, the California power crisis, and the Enron scandals, momentum flagged for bringing restructuring to New England’s consumer retail natural gas supply.
The new electric regime has brought customers a more complicated electric bill. While most customers just see at the end of the month one total amount owed to Emera, Eversource, Green Mountain Power, National Grid, Unitil or another utility, within that aggregate number they’re paying for

- a delivery cost for electricity used, per kilowatt-hour of consumption.
- other fees for their share of the cost of New England’s transmission system, which is apportioned among the six states according to their share of New England’s total demand on the grid, and then by state to ratepayers.
- their “transition cost” share of paying off the “stranded costs” of pre-restructuring power plants and electric supply contracts.
- fees for promoting renewable energy and energy efficiency.
- and the “supply charge” for the cost, per kilowatt-hour, of the energy they used.

While that last charge, the supply or energy cost, gets paid to your utility, in every state except Vermont and some areas of New Hampshire, none of that power is generated by your utility. In restructured markets, utilities shop on behalf of their customers for the best prices they can find from power suppliers. Once the price has been vetted and approved by state regulators, they pass on that cost directly to ratepayers, without taking a profit. Larger business, commercial, and industrial customers—and a small minority of residential customers—can and do shop directly with competitive suppliers for electricity and pay their utility only for delivering it to them, and have saved tens of millions of dollars annually since restructuring. But even 15 years after competition and choice came to the market, most New England residential and small-business customers are relying on their utility to provide them what is called “basic service” or “provider of last resort” electricity. For smaller retail customers, competitive suppliers have struggled to consistently beat utility prices and attract significant numbers of customers.
Vermont opted not to pursue restructuring, as it is such a small market for power, with roughly half the state’s demand met by imports from Hydro Quebec and, since the closing of Vermont Yankee, much of the rest from widely distributed hydroelectric dams and imports from other states. New Hampshire began restructuring in the early 2000s, but it has taken years to agree on terms for utilities to divest all their generating assets. It was only on July 1, 2016, that the New Hampshire Public Utilities Commission (NHPUC) finally approved a plan for Eversource to divest its last remaining generation assets: the 439-megawatt coal-fired Merrimack Station in Bow; the 400-megawatt oil- and gas-powered Newington Station in Portsmouth; the 150-megawatt Schiller Station in Portsmouth that includes coal-, oil-, and wood-chip-powered units; and nine hydroelectric units totaling 69 megawatts of output. Approval of the divestiture was contested for years over questions including how to reimburse Eversource for major air-pollution-control investments including a “mercury scrubber” at Merrimack. The NHPUC deal allows Eversource to recoup $415 million over several years for the Merrimack upgrades. The commission estimates Eversource customers will save $165 million over five years, and millions more after that, if the plants are successfully sold to new owners by the end of this year. Eversource owns the former Public Service of New Hampshire and Connecticut Valley Electric, which serve about 70 percent of the state’s electric customers.

Unlike shopping for other products that are delivered to your address, electrons can’t be steered to a specific location. So when customers shop for competitive electric supply, they are effectively paying to have a supplier deliver into the New England power grid the same amount of electricity as those customers take out of it at their home, business, school, hospital, or factory. Explaining this process merits a look at how New England’s power grid works.

BACKGROUND ON THE NEW ENGLAND POWER GRID

While New England has dozens of investor-owned utilities, local municipal light departments, electric cooperatives, and other “electric companies,” with the exception of a small part of northernmost Maine, all these electric distribution entities are interconnected in one unified power grid. The grid functions physically as a single pool or source of electricity that flows through utilities to customers in all six states. ISO New England has among other responsibilities the job of overseeing the second-to-second functioning of the power grid and ensuring supplies coming into the grid are always equal to demand for electricity coming out of the grid.

The New England grid includes 350 utility-scale generation sources totaling 31,000 megawatts of output capacity (providing a reliability cushion over the all-time peak demand of 28,130 megawatts for the region set on August 2, 2006) connected by 8,600 miles of transmission lines to customers. (One megawatt of generation capacity is enough to cover the electric needs of 750 to 1,000 average New England homes at a time.) New England also has 13 transmission interconnections allowing us to import, and less often export, power from and to New York, Quebec, and New Brunswick (9 to and from New York, and two apiece to and from Quebec and New Brunswick). About 16 percent of the electricity New England used in 2014 was imported from neighboring grids, according to ISO New England, most of that hydropower from Quebec.

Apart from the physical numbers of assets and devices that make up the grid, the entire market for power in New England comprises about 500 “market participants” who are represented at ISO New England by the New England Power Pool (NEPOOL). This is a committee that represents everyone who generates, buys, sells, transports, and uses wholesale—not retail—electric power, as well as entities that implement “demand response” measures to reduce demand for power at peak times.
Major Power Plants in New England
<table>
<thead>
<tr>
<th>State</th>
<th>Plant Name</th>
<th>Location</th>
<th>Fuel Source</th>
<th>Peak Summer MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>Bridgeport</td>
<td>Bridgeport</td>
<td>gas</td>
<td>454 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Bridgeport</td>
<td>Bridgeport</td>
<td>coal</td>
<td>400 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Kleen Energy</td>
<td>Middletown</td>
<td>gas</td>
<td>622 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Lake Road</td>
<td>Killingly</td>
<td>gas</td>
<td>757 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Milford</td>
<td>Milford</td>
<td>gas</td>
<td>507 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Millstone 2</td>
<td>Waterford</td>
<td>nuclear</td>
<td>898 MW</td>
</tr>
<tr>
<td></td>
<td>Millstone 3</td>
<td>Waterford</td>
<td>nuclear</td>
<td>1,225 MW</td>
</tr>
<tr>
<td></td>
<td>Montville Station</td>
<td>Uncasville</td>
<td>oil</td>
<td>497 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>New Haven Harbor</td>
<td>New Haven</td>
<td>oil</td>
<td>572 MW (4 units)</td>
</tr>
<tr>
<td>MA</td>
<td>ANP Bellingham</td>
<td>Bellingham</td>
<td>gas</td>
<td>472 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>ANP Blackstone</td>
<td>Blackstone</td>
<td>gas</td>
<td>473 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Bear Swamp</td>
<td>Rowe</td>
<td>pumped hydro</td>
<td>600 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Bellingham Cogen</td>
<td>Bellingham</td>
<td>gas</td>
<td>264 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Brayton Point</td>
<td>Somerset</td>
<td>coal and oil</td>
<td>1,505 MW (4 units)</td>
</tr>
<tr>
<td></td>
<td>Canal</td>
<td>Sandwich</td>
<td>oil</td>
<td>1,113 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Fore River</td>
<td>Weymouth</td>
<td>gas</td>
<td>726 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Kendall</td>
<td>Cambridge</td>
<td>gas</td>
<td>215 MW (4 units)</td>
</tr>
<tr>
<td></td>
<td>Millennium Power</td>
<td>Charlton</td>
<td>gas</td>
<td>335 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Mystic</td>
<td>Everett</td>
<td>gas and oil</td>
<td>1,996 MW (8 units)</td>
</tr>
<tr>
<td></td>
<td>Northfield Mountain</td>
<td>Erving</td>
<td>pumped hydro</td>
<td>1,146 MW (4 units)</td>
</tr>
<tr>
<td></td>
<td>Pilgrim</td>
<td>Plymouth</td>
<td>nuclear</td>
<td>678 MW</td>
</tr>
<tr>
<td></td>
<td>Stony Brook</td>
<td>Ludlow</td>
<td>oil</td>
<td>441 MW (9 units)</td>
</tr>
<tr>
<td>ME</td>
<td>Bucksport</td>
<td>Hancock</td>
<td>gas</td>
<td>274 MW (4 units)</td>
</tr>
<tr>
<td></td>
<td>Maine Independence</td>
<td>Veazie</td>
<td>gas</td>
<td>491 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Rumford Power</td>
<td>Oxford</td>
<td>gas</td>
<td>254 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Wyman</td>
<td>Cumberland</td>
<td>oil</td>
<td>811 MW (4 units)</td>
</tr>
<tr>
<td>NH</td>
<td>Essential Power</td>
<td>Newington</td>
<td>gas</td>
<td>523 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Granite Ridge</td>
<td>Londonderry</td>
<td>gas</td>
<td>678 MW (3 units)</td>
</tr>
<tr>
<td></td>
<td>Merrimack</td>
<td>Bow</td>
<td>coal and oil</td>
<td>473 MW (4 units)</td>
</tr>
<tr>
<td></td>
<td>Newington</td>
<td>Portsmouth</td>
<td>oil</td>
<td>400 MW</td>
</tr>
<tr>
<td></td>
<td>Seabrook</td>
<td>Seabrook</td>
<td>nuclear</td>
<td>1,246 MW</td>
</tr>
<tr>
<td></td>
<td>Schiller</td>
<td>Portsmouth</td>
<td>coal, wood, oil</td>
<td>156 MW (4 units)</td>
</tr>
<tr>
<td>RI</td>
<td>Entergy RISE</td>
<td>Johnston</td>
<td>gas</td>
<td>538 MW</td>
</tr>
<tr>
<td></td>
<td>Manchester Street</td>
<td>Providence</td>
<td>gas</td>
<td>447 MW</td>
</tr>
<tr>
<td></td>
<td>Ocean State</td>
<td>Burrillville</td>
<td>gas</td>
<td>438 MW (2 units)</td>
</tr>
<tr>
<td></td>
<td>Tiverton Power</td>
<td>Tiverton</td>
<td>gas</td>
<td>250 MW</td>
</tr>
<tr>
<td>VT</td>
<td>N/A—All small-scale and distributed hydro</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: U.S. Energy Information Administration Form 860, released October 21, 2015, with final data for 2014. Plant megawatt ratings are “summer capacity;” winter ratings may be higher. Megawatt totals for sites may include multiple units at a single generating complex.
HOW GAS HAS COME TO DOMINATE THE ELECTRIC GRID

Since the industry restructuring of the 1990s, natural gas has come to be the leading fuel for producing electricity to fuel the grid because of its price and emissions characteristics, and because as a practical matter no other source in the early 2000’s proved physically and politically feasible and acceptable on a large scale. As restructuring took effect, many legacy power plants rapidly proved unaffordable and unable to compete for customers in the new marketplace—especially smaller, older nuclear plants and older coal- and oil-fired power plants with high and growing costs for reducing emissions of sulfur dioxide and nitrogen oxides to meet ever-tighter pollution controls. At the same time, the improving efficiency, economics, and emissions characteristics of gas-fired combined-cycle power plants in the late 1990s and early 2000s made them much stronger competitors in the power market.

As a result, from 1995 to 2010, over 10,000 megawatts of new gas-fired generating capacity was approved, funded, installed, and deployed across the New England power grid. The percentage of electricity New England got from natural gas jumped from just 5% in 1990 and 15% in 2000 to 44% by 2014—almost exactly offsetting an equal drop in how much power the region got from older oil- and coal-burning plants. Nuclear output as a share of regional electric demand, even after all the Yankee closings, actually rose slightly, from 31% in 1990 to 34% in 2014, according to ISO data.

From a cost-to-consumers standpoint, even more important than how much of New England’s total electricity comes from natural gas is how often New England’s electric costs are determined by the price of natural gas. This requires an explanation of electric pricing in the New England wholesale market.

Much of the electricity flowing through the grid at any time has been bought and paid for under what are called bilateral contracts: Utilities and large end users buying months’ or years’ worth of continuous electric supply at pre-negotiated prices from power-plant owners and energy marketers. But at almost all times, the grid is also using “spot market” power whose price is determined at the moment of use. For every day, generation owners will submit a price per megawatt-hour at which they will agree to produce various amounts of energy from their power plants or generation supplies during a specific hour of the day. Those prices are ranked from cheapest to most expensive in a “bid stack.” As ISO-New England monitors and balances demand and supply, grid managers “dispatch” plants to run in reverse order of cost, from cheapest to most expensive. The price demanded by the very last output of production needed to meet the demand in a given hour becomes the “clearing price” paid to everyone providing power to the spot market in that hour. A very simplified example: If three plants bid to produce power for $30, $40, and $50 a megawatt-hour at 2 p.m. on Tuesday, and all three plants’ output is needed to meet demand at 2 p.m. on Tuesday, all three plants will be paid $50 an hour, because that was the “market clearing price.” Over the course of a year, clearing prices in the spot market will have a significant impact on the prices that end users can negotiate in long-term bilateral contracts for power.

As described later on, New England’s growing “demand response” programs, reinvigorated by a favorable U.S. Supreme Court ruling in January 2016, counterbalance price spikes by paying customers to use less power at times of peak demand. That lowers total demand, which lowers the market clearing price for the entire spot market. The huge power of demand response comes from the reality that a very small number of hours per year account for a disproportionate annual cost of electricity. Just 1 percent of all hours of electric consumption in New England account for 8 percent of the region’s total cost of electricity, and the top 10 percent of demand hours (typically summer hot spells, winter afternoons, or periods when grid managers are coping with a supply failure) account for 40 percent of spending, according to Massachusetts Department of Energy Resources Data.
The fact that such a small proportion of electric usage accounts so disproportionately for overall annual electric costs for New England is explained by a quirk of electricity virtually unique among all commodities: It can’t yet be stored in any meaningful quantities. So while most consumers’ prices for energy are fixed for six months at a time, at the wholesale level, at periods of peak strain on the grid, prices can soar to 10 or even 20 times the typical average price. Once efforts at maximizing conservation and curbing demand have been reached, at periods of extreme demand and limited supply, suppliers of electricity can require—and get—whatever price they propose to run the generation needed. ISO New England caps the maximum price for a megawatt hour at $1,000. In a crisis moment, the alternative to paying for $1,000 power is grid managers imposing Third-World-style rolling blackouts to ration available supply, something generally considered unacceptable in New England and the U.S. outside of extraordinary circumstances. In the example of the 2 p.m. Tuesday power demand, owners of “peaking units” like jet-engine generators designed to be fired up only a few times a year may demand the maximum $1,000 per megawatt hour to run if needed in that hour. Or owners of a gas- or oil-fired plant running at 99 percent capacity may have submitted an offer to crank it up to 100 or 102 percent of its rated capacity if they get paid $1,000 per megawatt hour, to compensate for strain on the unit and the risk of breakdown. A small number of hours of $1,000 power in a market where power is usually selling for $50 or $70 will heavily influence the total annual cost of electricity for everyone. Generating companies argue that these price spikes are not examples of price gouging, but rather of a properly functioning wholesale market sending clear—if rare or even extraordinary—signals about when and where new generating capacity will be needed to meet unusual levels of demand or extreme operating conditions.

Even in the competitive market, occasionally plants more expensive than the spot market clearing price will be called on to operate—or “run out of merit”—to maintain reliable service in specific areas or compensate for a transmission or technical problem. ISO New England has at times required power plants whose owners wanted to close them down to keep operating under “reliability/must run” orders paying them a premium price to stay in business, but these are much less commonly used than they were in the early 2000’s.

Natural gas power plants, according to ISO New England, set the overall spot market price in New England about 70 percent of the time, and thus dominate overall market price trends. A main reason for this is that nuclear, coal, and hydroelectric plants generally run most efficiently when they are producing power within a steady range for days, weeks, or even months at a time rather than frequently cycling output up or down. Nuclear, coal, and hydro often will be bid into the market at lower prices intended to ensure they get called to run consistently. They tend to be the plants that are producing round-the-clock “baseload” power for hospitals, traffic lights, refrigerators, and telecommunications networks that operate 24/7/365. Cycling output up and down is much easier, safer, and cheaper for gas plants, so a gas plant tends overwhelmingly to be the last unit called to meet the last increment of electric demand on the New England grid. Thus, most of the time the cost of the natural gas used in the power plants that set New England’s market price is the single biggest determinant of electric prices and, over time, electric rates. Price charts from ISO New England and others show that wholesale electric rates in the region tend to move almost in lockstep with natural gas prices, especially in the winter.

That tight link between gas and electricity in New England is one of the most important factors driving the complex decisions and choices facing New England’s legislators, regulators, and policymakers. And demand for gas is not slowing down. In its 2016 Annual Energy Outlook, the U.S. Energy Information Administration predicted that New England’s consumption of natural gas will continue to grow by an average of 0.2 percent annually from 2015 to 2040, even as the total use of
energy in the region drops by 0.1 percent annually—reflecting a continued shift from oil and power-plant coal to gas.

Demand for gas for power generation shows no signs of easing in New England. Besides plants such as Pilgrim and Brayton Point actually scheduled to shut down, ISO-New England identifies in its 2016 Regional Energy Outlook 11 plants it considers to be economically “at risk” of shutting down: Yarmouth in Maine; Merrimack, Newington, and Schiller in New Hampshire (soon to be divested by Eversource); West Springfield, Mystic, and Canal in Massachusetts; and Middletown, Montville, New Haven, and Bridgeport 3 in Connecticut. The ISO’s 2015 Regional System Plan identifies 1,498 megawatts of generating capacity closing by mid-2017, along with 785 MW of capacity coming online in 2016 and 1,022 in 2018. All the new units will be fueled by natural gas. Overall, in the ISO’s current planning horizon, close to two-thirds of all pending proposals for power generation for New England are gas-fired plants, with the balance large-scale wind and hydro. As of January 2016, 13,000 megawatts of proposed generation capacity was “in the queue” with the ISO to be approved as eligible to interconnect to the grid. More than 60 percent of that, 8,200 megawatts, is gas-fired generation, most of the rest, 4,200 megawatts, wind, according to the 2016 REO.

A total of 13,650 megawatts of generating capacity in New England, 44 percent of the total, now runs on gas, according to the ISO’s 2016 State of the Grid report. But the ISO’s 2015-16 winter outlook identified “up to 4,220 megawatts of natural-gas-fired generation at risk of not being able to get fuel when needed.” This is because generators generally won’t or can’t economically commit to “primary firm service” and take “interruptible service” instead. In the workings of the competitive wholesale market, they don’t know which days they will definitely be called on by the ISO to run and produce electricity and so can’t justify committing hundreds of thousands or millions of dollars to contracting for gas supply they may not wind up using. (The ISO, at the same time, has reported problems in the past of not being able to know ahead of time if a generator whose bid has been taken to produce electricity will actually get the gas they need to be able to deliver that power. The ISO has been working in recent years to improve its visibility into gas-supply reliability).

One of the major ways ISO-New England has tried to protect against a loss of gas supply has been, since 2013, to pay gas-fired power plants to be “dual-fuel” capable, able to switch to running on stored oil on short notice. Under its Winter Reliability Program, the ISO has been paying power plant owners $35 million to $70 million a year to help cover the cost of having up to 10 days’ supply of oil on hand—oil the plant owners do not know in advance whether they will need to use or not. The cost of this subsidy is added to all ratepayers’ bills through a “tariff,” and was $34.7 million in the winter of 2015-16. Currently about 30 percent of all gas-fired generation capacity in the region can switch to oil if called to. ISO-New England plans to continue offering payments to plants for capability to run on oil through the 2016-17 and 2017-18 winters. The main downside to this strategy is that plants emit far more pollution burning oil than gas and then have to go offline for hours or days to clean out the turbines to resume burning gas. In many cases, plants are restricted by state environmental regulations or license conditions on how many hours they can run on oil per month or per year.
As described above, the ultimate overall cost of electricity in New England depends heavily on which kind of fuel is establishing the “market clearing price” most of the time, how often it is a fuel source other than natural gas, and how much prices spike during periods of intense demand. To an extent, energy economists can predict what electric prices will be in the future, based on historic demand trends, if they know the mix of power plants available, the cost of natural gas, how much “demand response” may curb peak power demand at what price levels, and other factors that all go into where supply and demand intersect, and at what price.

Policy choices and laws designed to introduce more hydro, wind, or gas (at electric ratepayer expense) to help lower electric costs all amount to decisions that put a thumb on a side of a very complicated scale. They are choices driven by environmental values and economic goals. But calculating their impact on the ultimate prices that businesses, institutions, and consumers will pay for electricity becomes an even more complicated—and contentious—exercise. Regardless of their perceived merit, policy choices add distortions to what is otherwise, at least in theory, a classic free market, and will create winners and losers, savings and costs, and it’s important for policymakers to try to fully enumerate those questions and quantify answers as much as they can. Examples of questions some of the current policy initiatives raise are:

- If Vermont Yankee and Pilgrim have or will shut down because they could no longer economically compete in a natural-gas-driven market, what impact would adding still more gas have on Seabrook and Millstone—both how often they run and their long-term economic viability?

- What would it mean for New England’s likelihood of attaining emissions and climate change goals to lose significantly more nuclear power, either from having units called to run less often, or by their potentially being driven out of business—as five nuclear plants in the region already have or will be?

- What would be the impact of adding one or two very large power plants’ worth of imported hydroelectric power on the overall price of power, need for more gas, and economic viability of offshore wind?

- Conversely, what would be the impact of adding one or two or more very large power plants’ worth of offshore wind power on the overall price of power, need for more gas, and economic viability of imported hydroelectricity?

- How fair, or unfair, is it for existing generators and demand response providers who compete in energy markets every day to get new competition from hydro and wind projects that can lock in 20-year contracts?

- At the same time, how can a new hydro or wind power supply that may require $1 billion or more in transmission upgrades fairly compete with gas or nuclear plants already connected to the grid without some way to recoup the transmission cost over time?
A look at the analytical back-and-forth over just one project, the $1.6 billion Eversource-Hydro Quebec Northern Pass project to bring increased supplies of Quebec hydropower into New England through new transmission lines, illustrates much of this complexity. A September 2015 report by The Analysis Group, conducted for the New England Power Generators Association, estimated that New England consumers would pay $777 million a year above market prices for the power Northern Pass would deliver, or some $20 billion over the 15- to 25-year life of a contract, largely because of the added transmission cost. The report also argued that more long-term hydro imports would “artificially suppress wholesale energy prices and undermine the financial viability of other, more cost-effective generating assets (e.g., existing nuclear plants) that are otherwise important for a low-carbon electricity supply.

A rebuttal report published April 25, 2016, by Power Advisory LLC for the Massachusetts Clean Electricity Partnership, “Analysis of Benefits of Clean Electricity Imports to Massachusetts Customers,” argued the importation of 18.9 tWh per year (18.9 billion kWh, or about 13 percent of total 2020 forecast New England demand) of “clean power” from various Canadian sources would save New England consumers $1.072 billion per year, or about 6 percent on average in New England and 8 percent in Massachusetts. The underlying analysis (available at www.masscleanelectricity.org) points to the myriad economic impacts any big change in power supply creates, including:

- $476 million in direct savings on wholesale electric costs
- $300 million a year in savings through downward pressure on demand for gas that lowers its price by 5 percent at the wholesale level and thereby indirectly lowers electric costs;
- and another $344 million in annual savings by reducing the need for older, less efficient plants to operate, which would reduce their value—and ultimate cost to electric ratepayers—in the wholesale capacity market.

While every one of those numbers can be disputed based on applying different cost assumptions, the key reality they underscore is that any new source of energy will have not just direct impacts on the price of electricity—but also second and tertiary impacts through how that new source affects the economics of other sources of electricity, and then a cascade of follow-on effects from there.

**HOW NEW ENGLAND GETS NATURAL GAS**

New England is often described as being at “the end of the energy pipeline” because it has no native sources of oil or natural gas production. Currently, the region has incoming gas pipeline with a capacity of 3.95 billion cubic feet per day, according to the Energy Information Administration. This includes five pipelines from the west, north and northeast, plus a liquefied natural gas LNG station close to Boston and two offshore LNG delivery points in Boston Harbor. (One of the delivery points in Boston Harbor was idled in mid-2013 because of low demand.) LNG is a form of natural gas that has been chilled to liquid, shrinking it to 1/600th its volume in its gaseous state. LNG is “vaporized” to be injected back into gas pipes. The LNG facility at Canaport in New Brunswick is a key source of New England supply as it feeds gas into the Maritimes & Northeast pipeline entering Maine, especially as output from the Sable Island gas field dwindles.

Several of these pipeline systems are known by multiple names. The Algonquin system is owned by Spectra Energy. The Iroquois system is owned 50-50 by Dominion and TransCanada. The Tennessee system is owned by Kinder Morgan.
About New England’s Gas Network

In addition to the five pipelines that deliver gas into New England, liquefied natural gas terminals play a key role in meeting the region’s need for gas for heating and electric generation. LNG is a form of natural gas that has been chilled and condensed to 1/600th its volume as a gas and can be transported by tanker ship or truck. LNG is revaporized to be injected into the pipeline and local distribution network:

- The Distrigas (Engie) in Everett MA can store up to 3.4 billion cubic feet and re-gasify up to 715 million cubic feet per day continuously into the Tennessee and Algonquin pipeline systems and send out 100 million cubic feet per day by truck. In 2015, Distrigas imported 50 billion cubic feet of gas, equal to 54 percent of all natural gas imports for the U.S. as a whole (Source: Northeast Gas Association May 2016 Regional Market Outlook). Distrigas typically imported 150 billion cubic feet annually between 2005 to 2010.

- Two offshore LNG hubs in Boston Harbor, Neptune and Excelerate’s Northeast Gateway, can add another combined 635 million cubic feet per day into the pipeline system. However, Neptune suspended its operating license for five years in the summer of 2013 because of low utilization. Northeast is rated for maximum output of 400 million cubic feet per day, but delivered output depends on available capacity in the network. Northeast Gateway had no shipments in 2011-14, but brought in 2.6 billion cubic feet during January and February of 2015 and 2.3 billion cubic feet in January and February of 2016, according to NEGA.

- Also key to New England’s gas supply is the Canaport LNG facility in Saint John, New Brunswick. Canaport can feed up to 833 million cubic feet of gas per day into the Maritimes & Northeast Pipeline, which delivers gas through Maine to all of New England. Canaport delivered 23 billion cubic feet into New England in 2015.

- Local gas distribution companies such as National Grid and Eversource can store 16 billion cubic feet of gas on their own systems, a number that would grow with completion of a new LNG storage facility planned at Eversource’s existing Acushnet, Massachusetts, LNG facility as part of Spectra’s Access Northeast project. (The 40-year-old Acushnet facility, with two tanks with a capacity of 0.5 billion cubic feet, would be upgraded to four tanks with 6.8 billion cubic feet of capacity, all within the existing 250-acre footprint of the facility. A new 3-mile pipeline extension would connect the Acushnet facility to the Algonquin transmission line, according to AccessNortheastEnergy.com. National Grid has a dozen LNG storage facilities on its network that can supply 40 percent of customers’ demand on peak days. While it pursues plans to upgrade its LNG operation in Providence, Rhode Island, National Grid is also seeking a second facility in “south central New England” to add additional capacity by 2019 or 2020.

- The region has a total of 2,647 miles of gas transmission pipeline, according to the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration.

- The ISO’s 2015 Regional System Plan has detailed additional information about gas supplies at page 129.
GAS PIPELINES AND LNG

- Algonquin Gas Transmission Co.
- Granite State Gas Transmission System
- Iroquois Gas Transmission System
- Maritimes & Northeast Pipeline LLC
- Portland Natural Gas Transmission System
- Tennessee Gas Pipeline Co.
- Vermont Gas Systems Inc.

- Interconnect Points
- LNG Facilities
GAS OUTLOOK: AMPLE SUPPLY, AMPLE DEMAND, CONSTRAINTS

The ISO New England 2015 Regional System Plan is built on a prediction that northeast regional gas production, from Marcellus Shale fields in Pennsylvania, Ohio, and neighboring states, will rise from 3.92 trillion cubic feet in 2013 to 6.66 trillion cubic feet in 2024. The Northeast Gas Association says the Marcellus Shale may hold 500 trillion cubic feet of gas in all. Production was 16 billion cubic feet per day in 2015 and could grow in time to 25 billion, the NEGA says.

But, as the numbers on gas-fired electric generation above show, demand for gas has grown robustly—not just for electric generation but for conventional heating purposes, as tens of thousands of New England homeowners and businesses have converted to natural gas fuel since the 1990s.


According to the Northeast Gas Association, the number of residential customers using natural gas—mostly after switching over from home heating oil, and also construction of new residences in areas served by gas—was 14.6% higher in 2014 than it was in 2000, and 29.7% higher in 2014 than in 1990. Here are numbers of residential units heated by gas in each state by year, according to the Northeast Gas Association:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>428,912</td>
<td>458,388</td>
<td>475,221</td>
<td>522,658</td>
</tr>
<tr>
<td>ME</td>
<td>12,000</td>
<td>17,111</td>
<td>18,633</td>
<td>27,047</td>
</tr>
<tr>
<td>MA</td>
<td>1,118,429</td>
<td>1,278,781</td>
<td>1,297,508</td>
<td>1,461,350</td>
</tr>
<tr>
<td>NH</td>
<td>65,310</td>
<td>82,813</td>
<td>94,473</td>
<td>99,146</td>
</tr>
<tr>
<td>RI</td>
<td>195,100</td>
<td>214,474</td>
<td>224,320</td>
<td>233,786</td>
</tr>
<tr>
<td>VT</td>
<td>18,300</td>
<td>28,532</td>
<td>33,015</td>
<td>39,917</td>
</tr>
<tr>
<td>New England</td>
<td>1,838,051</td>
<td>2,080,099</td>
<td>2,143,170</td>
<td>2,383,904</td>
</tr>
</tbody>
</table>

In its May 2016 Regional Market Outlook, the Northeast Gas Association said New England has 2.6 million natural gas customers, including 2.3 million who use gas to heat their homes and for cooking and heating, and 260,000 commercial and industrial customers. New England’s gas consumption breaks down to: 39 percent for power generation, 25 percent for residential, 23 percent for commercial, and 13 percent for industrial.

In some areas, this combination of increased demand for gas for conventional heating use and increased demand for gas for electric generation has created supply shortages. Berkshire Gas has since 2014 imposed a moratorium on new gas hookups in parts of Hampshire and Franklin Counties (including communities such as Amherst, Hadley, Hatfield, Deerfield, Greenfield, Montaque, Whately,
and Sunderland) and said those moratoria would be lifted only in November 2018 and only if the Kinder Morgan Northeast Direct project were completed. Columbia Gas of Massachusetts imposed a hookup moratorium at the end of 2014 in Northampton and Easthampton, Massachusetts. National Grid has a moratorium on new gas connections on the Lower Cape Cod in Massachusetts into 2018-19, but says this is not because of inadequate supply but because of a pipeline constriction in the mid-Cape it is fixing.

Plans for increased natural gas distribution in other parts of New England continue, but less aggressively than in the early 2000s. In New Hampshire, Liberty Gas has recently petitioned to expand service to Hanover, Lebanon, Pelham, and Windham but projects it will need additional gas supply capacity “in the near future” to continue to grow. Vermont Gas has faced environmental protests and disruptions as it builds its Addison Expansion Project to add gas service to Middlebury College and the surrounding communities. Avangrid’s Connecticut Gas in August 2016 announced plans to expand service to Bolton and Coventry in Tolland County, furthering its goal of converting 200,000 customers from heating oil to gas by 2023.

Pipeline capacity constraints are driving a growing trend of “off system portable natural gas delivery” projects in which CNG or LNG trucks load up at existing utility taps, then drive to plug in to customers such as paper mills, medical facilities, and farm and food processors. Liberty Gas’s petition to serve Hanover and Lebanon, New Hampshire, would use trucked-in LNG and CNG. Andover, Connecticut, is weighing plans for a Global CNG facility that would bring in 120 trucks per day, or five per hour, to feed in gas from November to March. While transportation of natural gas by truck has a long record of being far safer than most over-the-road trucking, local regulators are facing safety and siting concerns. Companies developing proposals and projects in New England for this technology include Global CNG, iNatGas (Innovative Natural Gas), NG Advantage, XNG/Xpress Natural Gas, and Irving Oil.

Multiple consultant reports have argued that New England needs more incoming gas capacity: An ICF International report for ISO New England in November 2014 found a potential gas-supply deficit of 1.7 billion cubic feet per day by 2020. A Black & Veatch report for NESCOE, the New England States Committee on Electricity, in August 2013 on electric generation needs from 2014 to 2029, argued adding 1.2 billion cubic feet of new capacity would be the least expensive long-term solution with the highest net benefit for New England. A September 2014 report by ICF International for the EISPC (Eastern Interconnection States Planning Council) projected a need for 1,600 to 9,000 inch-miles of new mains and laterals in the region by 2030. (An inch-mile refers to width times length of pipe; a 10-mile 24-inch gas pipe would total 240 inch-miles). And a
January 2015 Synapse Energy report for the Massachusetts Department of Energy Resources stated that Massachusetts alone needs 600 to 800 million cubic feet per day of additional gas capacity by 2020. Kinder Morgan’s Tennessee Gas said in a June 2015 filing with the Massachusetts Department of Public Utilities in docket 15-37 that “demand for pipeline capacity exceeds the availability of pipeline capacity on the Tennessee system nearly every day throughout the year.”

EXPANDING THE GAS NETWORK: PLANS MOVING, PLANS DROPPED

Many plans to expand the regional gas supply are moving forward, although Kinder Morgan announced on April 20, 2016, it was suspending development of its $3.3 billion Northeast Energy Direct pipeline to Dracut, Massachusetts. It officially withdrew the project from federal regulatory consideration on May 23. Since the submission of the plan to FERC in November 2015, Kinder said, the project had faced intense local opposition and had failed to attract enough customers to proceed into financing and construction. The Northeast Direct project would have supplied up to 2.2 billion cubic feet per day of gas capacity, or a roughly 36 percent increase in New England’s incoming pipeline capacity. NED’s route went 188 miles from near Wright, New York, to Dracut, including 64 miles in Massachusetts, 91 percent of that co-located with electric transmission corridors, and 71 miles in New Hampshire, 87 percent adjacent to or overlapping a 345-kilovolt transmission line. Much of the non-utility-corridor new routing of the line was to avoid wetlands and environmentally sensitive areas the existing transmission corridors passed through. NED was planned to go into service in November 2018.

Kinder/Tennessee is, however, moving forward with a Connecticut gas expansion after winning a lawsuit against the project in Berkshire Superior Court in Massachusetts. The judge ruled that under Federal Gas Act, the company does not need a two-thirds vote of the Massachusetts Legislature to construct a pipeline section through a state forest. The Tennessee Gas Connecticut Expansion was aimed to be in service by November 2016 and involves constructing a 13.5-mile pipeline loop to deliver 72 million additional cubic feet per day of gas into Connecticut.

Spectra/Algonquin has one project nearing completion and two others moving ahead in development. Spectra’s Alqonquin Incremental Market (AIM) project is expected to come on line in November 2017 and add 340 million cubic feet per day of additional capacity, an 8.6 percent expansion of New England’s pipeline gas supply and 7.6 percent addition to the current peak demand design day for the gas system. This $1 billion project includes upgrading many sections of existing 26-inch pipe to 42-inch diameter and upgrading the capacity of five compressor stations to increase gas throughput.

Secondly, Spectra Atlantic Bridge is a $750 million to $1 billion expansion of southwest-to-northeast gas delivery with capacity of 132 million cubic feet per day. However, the mayor of Weymouth, Massachusetts, in early May 2016 declared opposition to a planned $47 million compressor station, and the city’s Conservation Commission refused to issue a needed permit. Local critics fear noise, lights, explosions, and terrorism. Whether local opposition can preempt FERC’s power to approve the project is unclear. Many environmentalists express concern that Atlantic Bridge is part of an overall strategy to use pipeline capacity through New England to someday increase global exports of fracked Marcellus gas through eastern Canada. Gas companies note that there are no export facilities yet planned or proposed to serve such a market, and that global demand patterns overwhelmingly favor Gulf of Mexico facilities exporting to Asian markets via the Panama Canal, not exports from North America to a slow-growing Europe whose gas supplies come mainly from Russia.

Third, Spectra is working with Eversource, National Grid, and other companies on Access Northeast Energy (ANE). ANE would add 900 million cubic feet per day of additional capacity and link to about 70 percent of New England’s fleet of gas power plants. Some 95 percent of Access Northeast’s
project uses existing pipeline and utility corridors and infrastructure sites. Five new electric power plants now under construction or in planning all connect to the Algonquin system that would get more capacity: CPV Towantic in Oxford, Connecticut; Footprint Power in Salem, Massachusetts; Exelon’s Medway Peaker Project in Medway, Massachusetts; LS Power’s new turbines in Wallingford, Connecticut; and Invenergy’s proposed plant in Burrillville, Rhode Island. Besides the pipeline upgrades, ANE would also include a new LNG storage facility at Eversource’s existing Acushnet, Massachusetts, LNG complex. (The 40-year-old Acushnet facility, with two tanks with capacity of 0.5 billion cubic feet, would be upgraded to four tanks with 6.8 billion cubic feet of capacity, all within the existing 250-acre footprint of the facility. A new 3-mile pipeline extension would connect the Acushnet facility to the Algonquin transmission line.) (Source: AccessNortheastEnergy.com) However, a principal funding mechanism for the ANE pipeline expansion has been thrown into uncertainty by a Massachusetts court ruling, described at greater length below, overturning a state-approved plan to charge electric utility customers for gas capacity expansion.

A regularly updated list of planned expansions can be found at www.northeastgas.org/pipeline_expansion.php. ISO New England’s 2015 Regional System Plan figure 8.9 also outlines gas transmission upgrades proposed to serve New England.

SHOULD ELECTRIC CUSTOMERS BE BILLED FOR GAS UPGRADES?
The Spectra Access Northeast Energy project is one of the leading examples of a type of project envisioned by the New England governors’ December 2013 joint statement urging more regional investment in gas infrastructure. Under the ANE plan, which has been thrown into uncertainty by an August 17, 2016, ruling by the Massachusetts Supreme Judicial Court, electric customers of National Grid and Eversource in Massachusetts were to be charged for 20-year gas supply contracts executed through the utilities to help fund the pipeline project. Similar proposals are under consideration or have been conditionally approved in every other New England state except Vermont.

The basic theory behind this arrangement is: New England’s cost of electricity, as described earlier, depends heavily on the price of natural gas. More supply of gas coming into New England should theoretically reduce the price of gas. A lower cost of gas should mean a lower cost of electricity. Cheaper gas would mean cheaper electricity. So in broad terms, it is fair to electric customers who’d benefit from lower prices to pay for increased gas capacity. Of course, determining just how much this arrangement reduces electric rates turns on a long list of disputable assumptions and predictions about future electric demand and supply and the price of gas and electricity from various sources.

In February 2015, at the direction of Governor Charlie Baker, the Massachusetts Department of Energy Resources directed the state Department of Public Utilities to open a docket review on the question of using electric tariffs to pay for gas supply capacity. In October 2015, the DPU approved such a mechanism for electric utilities to pay for gas pipelines if they can be shown to have a “net benefit” for electric customers. In November 2015, Massachusetts Attorney General Maura Healey’s office released a report opposing the policy as creating more costs than benefits for consumers financially and environmentally. In January 2016, Eversource and National Grid filed with the DPU for approval of 20-year contracts for gas supply.

The Conservation Law Foundation (CLF) and Engie, owner of the LNG plant near Boston, sued to oppose the DPU’s approval of the Spectra-Eversource-Grid contracts. Attorney General Healey’s office, which normally would defend the Commonwealth in such a suit, filed a friend-of-the-court brief supporting CLF and Engie, and the commonwealth retained special outside counsel to defend the state.
On August 17, 2016, the Massachusetts SJC unanimously ruled in favor of CLF and Engie and against the DPU-approved funding mechanism. The key questions raised in the Massachusetts lawsuit:

Did the Massachusetts Department of Public Utilities have the statutory authority to approve purchases by electric companies of natural gas supply? Would such a contract violate the 1997 state restructuring act’s intention of removing utilities entirely from owning generation and generation-related assets? Is it fair that just certain Massachusetts electric customers would be paying for a project that would benefit all New England ratepayers? Is it fair to power generators that National Grid and Eversource would pay for increased capacity on a pipeline system that reaches only 70 percent of gas-fired power plants and may not clearly reduce the cost of gas for the remaining 30 percent? Within Massachusetts, is it fair to customers of Eversource and National Grid that they would have to pay for the cost of the pipeline capacity, but customers of Massachusetts’ 40 municipal electric utilities and Unitil would get savings from the plan without having to pay for it? And is it fair to Engie and other LNG owners that the state is acting to subsidize one form of gas delivery, pipelines, over another form of gas delivery, LNG?

Writing for the court, Justice Robert J. Cordy said that the pipeline tariff would "re-expose ratepayers to the very types of risks that the Legislature sought to protect them" from in the 1997 utility restructuring law. “The department’s interpretation of the statute as permitting electric distribution companies to shift the entire risk of the [natural gas] investment to the ratepayers is unreasonable, as it is precisely this type of shift that the Legislature sought to preclude through the restructuring act.”

The utilities argued they were acting to help consumers and to help solve a basic market failure—that the competitive market for New England electric supply is not properly set up to evaluate and value contracts that will require investment for decades, not just years. One example of why it is so difficult for power plants to line up investors for gas capacity and electric output is the volatility of the U.S. gas markets and the major shifts in prices. For example, eight years ago, the FERC was reviewing more than 30 proposals to import LNG. Now, with the price far lower and output far higher because of the fracking revolution, the FERC is reviewing more than 20 proposals to export natural gas from the U.S. Predicting what gas prices and production levels will look like in another eight years is challenging. National Grid also argues that almost every form of energy used by the public involves some level of broad subsidy by taxpayers and ratepayers: Dredging of shipping channels to keep them open for coal barges, or maintenance of highways used for servicing nuclear power plants. It’s not unprecedented, they argue, to seek broad subsidies for broad energy benefits.

National Grid, in a January 15, 2016, filing in Massachusetts DPU 16-05, said that signing two 20-year “firm contracts” for gas with Spectra’s Access Northeast Energy and the now-suspended Kinder Morgan/Tennessee Gas Northeast Direct pipeline would provide “levelized annual net benefits of $1.2 billion per year” from 2019-38 under normal weather conditions. National Grid estimated
the net present value to ratepayers of the plan at $10.9 billion, with 46 percent of that flowing to Massachusetts ratepayers and the other 54 percent to the rest of New England. With just ANE, New England would get levelized annual net benefits of $1.1 billion per year. National Grid has been hoping to get DPU approval to sign a pipeline contract by October 2016.

In a June 15, 2015, filing with the Massachusetts DPU in Docket # 15-37, Kinder Morgan’s Tennessee Gas unit said based on CES methodology, adding 1.0 to 1.2 billion cubic feet of increased delivery capacity would, after accounting for the cost to consumers of the upgrade, deliver a net annual cost savings of $661 to $700 million. The Tennessee pipeline serves, on a net-generation basis, 37 percent of New England’s existing installed gas-fired generation capacity.

However, a study conducted for Attorney General Healey’s office by The Analysis Group’s Paul Hibbard and Craig Aubuchon and released on November 18, 2015, found that adding incremental new gas capacity is not required to meet the state’s electric reliability needs. “Increasing natural gas transportation capacity in New England would lower wholesale electricity costs by lowering natural gas prices at times when the interstate pipeline system would otherwise face greater constraints,” the authors confirmed. But, they concluded New England has “underutilized LNG storage and vaporization capacity.” They also concluded that energy efficiency and demand-response measures can meet the state’s power needs more cheaply and cleanly. In the “most stressed scenario” they could envision, there was an electric reliability deficiency of 1,675 MW in 2024, growing to 2,480 MW by 2029-30, in just 26 hours across nine days, because of a deficiency of 420 million cubic feet per day of natural gas supply. The report assumes an increase in the number of gas-fired power plants that can switch to running on fuel oil when gas supplies are strained.

The Attorney General’s report concluded that new pipeline capacity would save ratepayers $61 million annually, but at the cost of producing 80,000 more tons of carbon dioxide annually that moves Massachusetts away from its Global Warming Solutions Act goals and requirements. Energy efficiency and demand response measures, the Healey report argued, would save more than twice as much, $146 million annually, and eliminate 1.86 million tons of carbon dioxide.

The SJC ruling raises the question of whether legislators could or will amend state law to allow electric utilities to enter into gas capacity contracts. However, proposals to make Massachusetts electric customers pay for gas pipeline capacity have generated major opposition from legislators. On June 30, 2016, the state Senate voted 39-0 in favor of an energy bill amendment prohibiting any such contracts, although this amendment was not included in the final House-Senate compromise legislation signed by Governor Baker. More than 90 Massachusetts state representatives had also sent the House speaker a letter opposing ratepayer support for more pipeline infrastructure as part of any pending bill.

How much more LNG can be counted on to offset the need for pipeline gas is debatable. LNG is increasingly a globally traded commodity, and after the 2011 Fukushima nuclear disaster in Japan, many shipments of LNG destined for Distrigas near Boston got diverted mid-ocean to Japan because the price for the fuel there soared. While shale gas from Pennsylvania delivered by pipeline can be secured under contract for years, LNG delivered by ship is likely to be considerably more expensive and subject to diversion to other parts of the world depending on market conditions.

From the standpoint of electric grid reliability, administrators at ISO-New England remain gravely worried about a worst case scenario if New Englanders are left without heat and electricity during a brutal winter cold snap. In this scenario, if the available gas transmission infrastructure can’t meet demands for gas for heat and power, under federal law, gas utilities holding “firm” contracts for fuel
would as a rule have priority over electric generators for the available fuel. What grid managers focused on reliability have to plan to avoid is a scenario where there is not enough gas supply in a given location for either heating or power generation needs, residential users are left with no electricity and no heat, and people may freeze to death in the dark. Thus the intense focus by ISO New England on ensuring there is enough slack in the system and redundancy—at a cost still to be determined—to prevent the risk of a human catastrophe.

CT, ME, NH, RI ON ELECTRIC CUSTOMERS PAYING FOR GAS

Four of the five other New England states besides Massachusetts—Connecticut, Maine, New Hampshire, and Rhode Island—are at some stage of considering or adopting plans like the now-overturned Massachusetts proposal to have electric customers pay for the cost of increased gas capacity.

In New Hampshire, in September 2015, the state Public Utilities Commission staff concluded that the commission “may hold that the NH electric distribution companies have authority to enter into gas capacity contracts for the benefit of gas-fired generators.” On February 18, 2016, Eversource filed with the state Public Utilities Commission to have customers of the former Public Service of New Hampshire pay for 20-year contracts for gas supply, mirroring the contract proposed in Massachusetts. Much like National Grid has estimated the plan will produce net savings for Massachusetts customers, Eversource’s analysts estimate the plan will deliver $140 million to $270 million in annual net savings over 20 years to Granite State electric customers, figures that other analysts have disputed.

In Maine, the Maine Energy Cost Reduction Act (MECRA), adopted in June 2013, authorized the state to have ratepayers pay for up to 200 million cubic feet of new natural gas capacity, at a cost of no more than $75 million annually. The process since then has been contentious: Consultants London Economics International LLC in 2014 warned the costs would exceed the benefits, leading to a 2-1 vote by the Maine Public Utility Commission in November 2014 against continuing with the plan. Maine Governor Paul LePage, however, has continued to advocate for more gas supply. On July 10, 2016, rejecting a negative recommendation by its staff, the PUC voted 3-0 in conditional favor of pursuing electric-ratepayer-funded gas capacity. Commissioners stipulated that Maine would move ahead on the plan only if other New England states also approved similar pipeline capacity contracts. The proceedings are docketed as Maine PUC 2014-0071.

In Rhode Island, National Grid filed with the state Public Utilities Commission a “Request for Approval of a Gas Capacity Contract and Cost Recovery” on June 30, 2016, that is similar to the Massachusetts and New Hampshire mechanisms for having electric customers pay for a 20-year gas supply contract. National Grid says the plan is “commercially reasonable and will provide net benefits at a reasonable cost to National Grid’s customers in the form of improved electric reliability and lower electric retail prices” and that it conforms to the Rhode Island Affordable Clean Energy Security enacted in July 2014. The Rhode Island proposal also includes a mechanism for buying and releasing LNG bought under the contract and for returning “a small fraction” of demonstrated savings to the utility “to create an inducement for future innovative efforts by the Company that promise to yield additional customer benefits.” More information about this plan may be found at http://www.ripuc.org/eventsactions/docket/4627page.html.

In Connecticut, the Department of Energy and Environmental Protection is—as of this writing—now working on completing an RFP to have electric distribution companies enter into agreements for gas transportation capacity, under the 2015 Act Concerning Affordable and Reliable Energy finalized DEEP March 17, 2015.
ENVIRONMENTALIST OPPOSITION TO NATURAL GAS

Measures to support and increase use of natural gas face strong opposition from many environmentalists who argue they make the region more dependent on a source of fuel whose carbon-dioxide emissions will aggravate global climate change. While natural gas was once hailed as a lower-emitting “bridge fuel”—bridging the transition period from dirtier coal and oil power plants to the fully renewable energy sources that would replace gas plants as the intermediate generation source—many critics of natural gas pipeline capacity expansion have become concerned these moves will leave New England “stuck on the bridge.” Environmentalists fear the region becoming more dependent for decades more on a fossil fuel for most of its electricity and heating. Additionally, critics argue that much of the new gas supply poised to enter New England from the Marcellus shale is produced in a way that is far more environmentally damaging than conventional Gulf of Mexico natural gas production of the 1990s and 2000s, with fracking raising concerns about pollution of water, earthquakes, and industrialization of bucolic rural areas. Many environmentalists also express suspicions—rebutto by industry executives, as described above—that plans to expand southwest-to-northeast gas capacity through New England are driven not only or mainly by New England capacity issues, but by a long-term strategy to build more and bigger routes to export “fracked gas” globally from the Marcellus through future coastal LNG terminals in New England and Eastern Canada.

At the same time, many energy experts note that at least at some level, natural-gas-fired generators are actually critical to making many forms of renewable energy fully viable. Because wind can slow down and the sun can be covered by clouds, output levels from wind turbines and solar photovoltaic panels can swing minute by minute. Until large-scale energy storage becomes more widespread and affordable, gas-fired power plants are seen by grid operators as the best option for rapidly increasing and decreasing output to supplement wind and solar as needed.

Another environmental concern about gas is that methane is a highly potent greenhouse gas, trapping far more heat in the atmosphere than equivalent amounts of carbon dioxide. Per pound emitted, according to the U.S. Environmental Protection Agency, methane has 25 times as big an impact on climate as carbon dioxide a 100-year period.

Some environmentalists argue states should force utilities to reduce or eliminate leaks of gas from their existing systems before paying for more capacity. Massachusetts’ new August 2016 environmental law includes several measures mandating increased leak repairs. But the total cost-benefit ratio of such policies, especially given the expense of digging up and repairing gas lines in urban areas, is challenging to calculate definitively. A 2015 study conducted for the Commonwealth of Massachusetts found that 0.6 to 1.1 percent of gas delivered into the state’s network of pipes was lost to emissions. Massachusetts and Rhode Island have adopted legislation to encourage replacement of cast-iron and bare-steel gas pipes, which are at particular risk of corroding and leaking. The average U.S. gas utility has a network made up of 5 percent bare steel and cast-iron components. The comparable numbers here are 24 percent in Massachusetts and 35 percent in Rhode Island. (More data are available in the Northeast Gas Association May 2016 Regional Outlook, page 22).
In Massachusetts, National Grid has plans to replace 463 miles of cast-iron pipe and 381 miles of unprotected steel from its service territories between 2016 and 2020. The total environmental impact in reduced methane emissions, 2,686.7 metric tonnes of methane, the company says, is comparable to eliminating 14,000 cars from the road or replacing 1.75 million incandescent light bulbs with compact fluorescents. From 2010 to 2015 Grid spent $856 million to replace 740 miles of gas mains.

In Rhode Island, where National Grid has 260,000 customers served by 3,210 miles of gas mains and 2,450 miles of service lines, National Grid says it has by repairs reduced the percentage of “leak-prone mains” from 53 percent of the system in 2006 to 39 percent of the system in 2015, including replacing 210 miles of leak-prone mains from 2011 to 2015. National Grid projects it will replace another 365 miles of leak-prone mains, our of 1,237 total in 2015, by 2020.

HEATING OIL AS A CONTINUING, RELIABLE, GREENER FUEL SOURCE

For all the growth in use of natural gas, representatives of the heating oil industry in New England note that they continue to supply more than 2 million homeowners with heating fuel in a completely private-sector energy network that does not require government subsidies or intervention. New low-sulfur requirements taking effect July 1, 2018, in all six New England states lower allowable sulfur in heating oil by 97 percent from current levels. And with increased use of plant-based “biofuels” blended into heating oil, taking into account the greenhouse gas effects of methane leaks, groups such as the National Oilheat Research Alliance (NORA) and New England Fuel Institute note that today’s heating oil can rival and exceed natural gas, measured over years, in greenhouse gas improvements. Availability of fuel oil/heating oil as a backup at natural-gas-fired electric generating stations has become a critical part of ISO New England’s winter grid reliability strategy. Heating oil has been an energy mainstay for much of New England for decades, and with ongoing improvements in its environmental and emissions characteristics, it will remain a key element in the discussion of the most optimal overall blend of energy sources to ensure affordable, reliable, environmentally sound electricity and heating for the region. Evaluating the extent to which new blends of fuel oil can rival natural gas and renewables in overall environmental impact will be an important issue for regional policymakers and regulators to pursue.

NEW ENGLAND’S ENERGY/ENVIRONMENTAL FRAMEWORK: RPS’S, RGGI, AND GLOBAL CLIMATE CHANGE LAWS

In all the debate over the cost and merits of promoting more natural gas or renewables, New England legislators and policymakers are operating within an energy-and-environment framework primarily defined by three major constructs:

1. Laws in all six states committing to specific reductions in emissions of carbon dioxide from all activity, including power generation, by specific dates in the future, most commonly 2020 and 2050.

2. The Regional Greenhouse Gas Initiative (RGGI) under which power plants in the region pay for the right to produce carbon dioxide, and those payments are reinvested into energy efficiency, renewables, and other projects.
3. Renewable Portfolio Standards intended to help states reach the climate change laws by requiring entities providing power to customers in each state to acquire minimum percentages of their supply from sources defined as renewable under each state’s law. (This may or may not include sales of “existing hydro” from Quebec, Connecticut River dams and large pumped-storage facilities in northwestern Massachusetts, and other sources, depending on the state’s legal definition.)

Laws for reducing emissions of greenhouse gases have emerged over several years in the six New England states and have a long history of support. On August 28, 2001, in fact, governors of the six states and premiers from five eastern Canadian provinces (New Brunswick, Newfoundland and Labrador, Nova Scotia, Prince Edward Island, and Quebec) also adopted a Climate Change Action Plan 2001 committing the 11 jurisdictions to an overall 10 percent reduction in greenhouse gas emissions from 1990 levels by 2020, and a “long-term goal” of reducing such emissions by 75 to 85 percent.

Here is a breakdown of the six states’ current commitments on greenhouse gas emissions:

<table>
<thead>
<tr>
<th>State</th>
<th>Applicable Law</th>
<th>2020</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>Public Act 8-98</td>
<td>10% below 1990</td>
<td>80% below 2001</td>
</tr>
<tr>
<td>ME</td>
<td>PL 237</td>
<td>10% below 1990</td>
<td>N/A</td>
</tr>
<tr>
<td>MA</td>
<td>Global Warming Solutions Act 2008</td>
<td>25% below 1990</td>
<td>80% below 1990</td>
</tr>
<tr>
<td>NH</td>
<td>Climate Action Plan</td>
<td>20% below 1990</td>
<td>80% below 1990</td>
</tr>
<tr>
<td>RI</td>
<td>Executive Climate Change Coordinating Council*</td>
<td>10% below 1990</td>
<td>80% below 1990</td>
</tr>
<tr>
<td>VT</td>
<td>Executive Order 07-05 2028</td>
<td>50% below 1990</td>
<td>75% below 1990</td>
</tr>
</tbody>
</table>

*RI adds intermediate 45% below 1990 by 2035 | Source: The Analysis Group, Healey report page 68

In Massachusetts, the discussion over what the 2008 Global Warming Solutions Act (GWSA) will require of the energy sector took a major new turn with a May 16, 2016, unanimous ruling by the Supreme Judicial Court in Kain et al. vs. Department of Environmental Protection. Throwing out a Superior Court ruling, the SJC ruled that DEP regulations had not fulfilled the “unambiguous language” of the 2008 GWSA requiring DEP to promulgate regulations “that address multiple sources of categories of greenhouse gas emissions, impose a limit on emissions that may be released, limit the aggregate emissions released from each group of regulated sources or categories of sources, set emissions limits for each year, and set limits that decline on an annual basis” within the building, heating, and transportation sectors. The SJC ruled that the regulations were to be promulgated January 1, 2012, and to take effect January 1, 2013. DEP contended it had met the requirements of the law by issuing policies and regulations for low-emissions vehicles, reduction of methane leaks from gas utilities, and using RGGI carbon auction proceeds to support energy conservation and demand reduction. Additionally, the SJC’s Kain ruling also raises questions about whether energy facilities physically located outside the Commonwealth of Massachusetts—such as new Canadian hydropower supplies that could come into the state under the energy legislation enacted in August 2016—can and will count towards measuring the state’s energy emissions or not.
How much more power-plant owners will be required to do to comply with the SJC ruling is unclear at this writing. The New England Power Generators Association notes that since 1990, Massachusetts power plants as a group have cut carbon dioxide emissions by half, while emissions from transportation have kept growing and are now twice as big a source as any other sector. A notable example of how power generators have factored in the GWSA: Developers of the Footprint Power plant on the site of the former coal- and oil-burning Salem Harbor power plant in Massachusetts faced opposition from environmentalists who contended the construction and operation of the plant would violate the goals and direction of the GWSA. Footprint’s solution was to negotiate a settlement agreement to operate for no more than 33 years and plan to close the plant by 2050.

Along with transportation and buildings, power generation is one of the biggest sources of greenhouse gas emissions but is especially amenable to reduction by central planning, because action by a small number of decision-makers can deliver large emissions reductions. Politically, it involves far fewer interests than addressing energy and emissions from vehicles and buildings. To that end, “renewable portfolio standards” for electric generation are a key component of meeting the power generation components of greenhouse gas reductions. Here is a list of the New England states’ Renewable Portfolio Standards, showing the minimum percentage of electric load served by electric distribution companies and competitive suppliers that must be met with “new” renewable energy (not existing hydro, except for Vermont):

<table>
<thead>
<tr>
<th>State</th>
<th>Standard for 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>ME</td>
<td>10%</td>
</tr>
<tr>
<td>NH</td>
<td>11%</td>
</tr>
<tr>
<td>RI</td>
<td>12.5%</td>
</tr>
<tr>
<td>MA</td>
<td>15%</td>
</tr>
<tr>
<td>CT</td>
<td>20%</td>
</tr>
<tr>
<td>VT</td>
<td>59% “total renewable energy,” which includes existing large hydro, 90% by 2050</td>
</tr>
</tbody>
</table>

(Source: ISO New England 2016 State of the Grid slide 30)

There’s not wide agreement over how significant a problem it is that New England states’ emissions goals and RPS’s differ. On one level, it could be simpler for renewable energy producers and marketers if New England had one single standard, definition, and goal for renewable energy use so one product in all six states could meet all six states’ environmental and energy requirements. At the same time, because of local policy preferences and considerations, different states have opted to support differing levels and mixes of existing and new hydro, solar, wind, and other renewables to meet their goals.

The third major driver of New England energy and environmental policy is the region’s participation in the Regional Greenhouse Gas Initiative. RGGI is a “cap and trade” program to reduce emissions of carbon dioxide by power plants that began on January 1, 2009, and today includes all six New
England states plus Delaware, Maryland, and New York. (New Jersey was an original member but later withdrew.) Power plant owners bid every quarter for the right to emit carbon dioxide in an auction that typically sets a price of around $2 to $5 per ton of carbon dioxide, under a total cap. That cap was tightened by 45 percent in 2014, to a new cap region-wide of 91 million tons of CO2. That decision came after it became clear the combination of improved carbon efficiency of generation and the economic impacts of the 2008-10 Great Recession had driven the region’s carbon output far below the old cap, so carbon emission allowances were likely to be of very low value and jeopardize revenue and ongoing environmental impact from RGGI.

There’s wide agreement that the carbon caps under RGGI, and the prices for carbon emissions they’ve yielded, are far too low in and of themselves to drive major climate-based turnover in the power generating fleet, or to substantially value the non-carbon-emitting attributes of nuclear power plants for the purposes of meeting states’ 2020 and 2050 emissions goals. RGGI has changed the total wholesale price of power by just a few percentage points a year at most. Nevertheless, RGGI has generally been considered successful as far as it goes, creating a framework and foundation for ongoing efforts to “price carbon” more effectively to meet energy and environmental goals.

The RGGI auctions have produced more than $1 billion in revenue so far, distributed back to participating states. New England has redirected RGGI revenues mostly to energy efficiency programs, renewable energy development, direct assistance to billpayers, and greenhouse gas abatement programs. (Rhode Island, for example, has used RGGI revenues to perform energy upgrades on 67 non-profit and community-buildings. Maine used RGGI revenues to distribute 1.9 million high-efficiency light bulbs).

The six New England states have received the following amounts of RGGI revenue cumulatively through the end of 2013:

<table>
<thead>
<tr>
<th>State</th>
<th>RGGI Revenue (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>$98.5</td>
</tr>
<tr>
<td>ME</td>
<td>$41.5</td>
</tr>
<tr>
<td>MA</td>
<td>$252.89</td>
</tr>
<tr>
<td>NH</td>
<td>$62.2</td>
</tr>
<tr>
<td>RI</td>
<td>$25.4</td>
</tr>
<tr>
<td>VT</td>
<td>$11.7</td>
</tr>
</tbody>
</table>


Renewable portfolio standards and RGGI have significantly helped the six states in moving towards their 2020 carbon goals. The region saw some backsliding in 2015, however, largely because of the shutdown of the Vermont Yankee nuclear power plant in Vernon at the end of 2014, removing a major source of non-carbon energy from the New England supply. Also, many dual-fuel gas/oil plants burned more polluting oil in the brutal winter of 2015 to ensure adequate availability of natural gas for heating, industry, and electricity generation.
Besides carbon-dioxide emission reductions from power plants of 26 percent between 1999 to 2014, according to the ISO New England 2016 Regional Energy Outlook, the region has achieved major progress in reducing air pollution and smog as coal and oil plants have been replaced. Over those years, according to the ISO, emissions by power plants of nitrogen oxides fell 66 percent and of sulfur dioxide 94 percent.

CONNECTICUT/MASSACHUSETTS/RHODE ISLAND CLEAN ENERGY RFP

Recognizing that they have common climate and emissions goals and could get better offers and prices by teaming up, Massachusetts, Connecticut, and Rhode Island jointly issued a “Clean Energy RFP” in November 2015. This followed Massachusetts Governor Charlie Baker’s filing in July 2015 of his initial version of the recently enacted legislation to facilitate purchases of long-term contracts for hydroelectric power, offshore wind, and other renewables by Massachusetts utilities. Baker asserted—although some utilities disagreed with him—that Massachusetts law as then written blocked utilities from being able to seek these kinds of long-term contracts, and his legislation would finally enable utilities to “test the market” for hydro and wind power and introduce some actual market-based cost estimates to the “green energy” debate.

Connecticut’s share of the RFP was authorized by the June 2015 enactment of “An Act Concerning Affordable and Reliable Energy.” Final details are being worked out in Hartford. Rhode Island’s participation in the RFP is under the aegis of the 2014 Rhode Island Affordable Clean Energy Security Act. National Grid—which serves 99 percent of the state’s electric customers—is acting on the state’s behalf as the agent negotiating clean power supplies for the state. Rhode Island’s state energy plan, “RI Energy 2035,” published on October 8, 2015, committed the state to seeking a “secure, cost-effective, and sustainable energy system” by 2035 through an “all-of-the-above clean energy framework.”

On January 28, 2016, the tri-state “New England Clean Energy Request for Proposals” drew more than two dozen proposals for up to 1,490 megawatts of new hydroelectric power from Canada, 600 megawatts of hydro from New York, and 3,500 megawatts “nameplate capacity” of land-based wind, and 750 megawatts of nameplate capacity from solar. (Actual megawatt output from wind and solar needs to be discounted from the “nameplate capacity” rating by the hours the wind is blowing at less than peak power production speeds or the sun is not shining.) Most of the wind power was contingent on development of three new transmission lines from Maine and two new lines from New York. More details on the bids responding to the RFP can be found at http://cleanenergyrfp.com/bids. The three states had been planning to complete their “evaluation phase” July 26, 2016, before moving ahead with bids, but that deadline has been extended indefinitely as this report goes to press.
WIND POWER WITHIN NEW ENGLAND AND OFF THE COAST

One of the biggest developments in New England energy markets over the next 20 years could be widespread development of large-scale wind-generated electricity off the region’s coasts, especially with the new Massachusetts law directing utilities to pursue contracts for 1,600 megawatts of new offshore wind generation.

New England had 850 megawatts of installed on-land wind capacity as of November 2015, with 4,100 megawatts in the interconnection queue, either under construction or in planning. (ISO New England 2015 Regional System Plan page 157) This includes 3,641 MW in Maine, 464 MW in Massachusetts, 91 MW in New Hampshire, and 47 MW in Vermont, according to the ISO. The remote location of many of the best areas for on-land wind generation, such as along the ridge lines of remote mountainous areas of northern New England, is driving the need for significant new capacity for electric transmission that has generated outright opposition to tall power pylons cutting through remote forested areas, or calls to have power lines put fully underground, which adds millions of dollars per mile and new operational complexity.

For offshore wind along New England’s southern coast, planning and investment activity is currently booming. Construction is underway now on Deepwater Wind’s five-turbine, 30-megawatt Block Island Wind Farm off the coast of Rhode Island. It is scheduled to begin producing power later this year.

DONG Energy’s Bay State Wind project envisions more than 1,000 megawatts of capacity in ocean tracts 130 feet to 160 feet deep located 15 nautical miles southwest of Martha’s Vineyard, with “gigawatts” of capacity online by 2030. DONG (originally Danish Oil and Natural Gas) has built to date 26 percent of all offshore wind capacity in the world, with 17 projects totaling 3,000 megawatts in operation, 5 projects totaling 3,300 megawatts under construction, and 11 projects totaling more than 5,000 megawatts under development. By 2020, DONG estimates, the cost of producing wind power offshore will drop by 35 to 40 percent from 2012 levels. DONG also recently took over the Ocean Wind project 10 miles off the coast of New Jersey and hopes to develop 1,000 megawatts of capacity in waters 65 to 100 feet deep.

OffshoreMW, working in partnership with the Vineyard Power Cooperative, was named in January 2015 the successful bidder for a lease on a 160,000-acre zone about 14 miles south of Martha’s Vineyard. It had not announced plans as this report went to press for how much wind power it plans to install and when.

For years, talk of offshore wind in New England has been dominated by controversy and lawsuits over the proposed Cape Wind project in Nantucket Sound. The newer offshore projects are proceeding in a far different regulatory and political environment. In contrast to Cape Wind identifying an area where it wanted to site turbines and public policy then moving to catch up, with the offshore projects, the U.S. Interior Department and dozens of stakeholder groups worked for years to identify areas with promising wind resources and ocean-floor topography, most invisible from shore, and then subtract shipping lanes, whale migration routes, areas of concern for bird and marine life, areas near aviation radar, and other sensitive zones from what was ultimately put out to bid. The process overseen by the U.S. Department of Energy in the 2010s identified and put out to public bid access to hundreds of square miles of deep water ocean tracts. In notable contrast to Cape Wind, the “deep offshore” projects have the virtue of being impossible or nearly impossible for people to see or perceive from land. (Massachusetts’ August 2016 energy law included a provision locking Cape Wind out of the state’s offshore wind bidding by restricting eligibility to projects in federally leased waters, on the Outer Continental Shelf, and at least 15 miles from inhabited areas).
The trade association Offshore Wind: MA (OffshoreWindMA.com) estimates that the waters off Massachusetts alone could support 8,000 megawatts of generating capacity. Studies show year-round, wind blows hard enough during 9 days out of 10 in this zone to produce power. One potential concern expressed by some developers, however, is how rapidly wind-turbine technology is changing and improving, meaning that between the time a project first files for technical interconnection approval with ISO New England and when it is ready to go to market, turbine technology may have jumped to a new level of capacity and the original technical documentation and regulatory approval will have become outdated. Additionally, some developers are now wondering whether U.S. Jones Act requirements for using only American-built and -crewed ships in domestic waters could put a crimp on availability of vessels to transport turbines, cabling, and construction workers and equipment.

RENEWABLE ENERGY PLANS NEED NEW TRANSMISSION

While New England has potentially huge use for hydro and land-based and offshore wind power, the success of many of these proposals will turn on construction and financing of new transmission lines to get the power from where it’s most readily available to the Boston-Providence-Hartford-Springfield-Worcester zone from which the vast majority of demand for electricity comes in New England. (Page 33 of the ISO’s 2016 Regional Energy Outlook illustrates how far the best wind generation capacity in New England is from the areas of highest demand for that power).

ISO New England has traditionally planned and recommended transmission projects to meet identified needs for reliability upgrades. But in response to the bevy of proposals for remote new hydro and wind power, and a new federal procedure called FERC Order 1000, the ISO has begun accepting proposals for “non-reliability” projects, including ones designed to meet “policy goals” such as more renewable power flowing into the grid. A total of 11 such proposals totaling over 7,000 megawatts of capacity were in the “interconnection queue” at the ISO as of January 2016, aimed at bringing hydro and wind from Quebec, Northern Maine, New Brunswick, and Newfoundland and Labrador to areas of concentrated demand in southern New England.

<table>
<thead>
<tr>
<th>Name</th>
<th>Sponsor</th>
<th>Power Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern Pass</td>
<td>Hydro Quebec and Eversource</td>
<td>1,090 MW Quebec to New Hampshire</td>
</tr>
<tr>
<td>Northeast Energy Link</td>
<td>Emera and National Grid</td>
<td>Maine to Massachusetts</td>
</tr>
<tr>
<td>Maine Green Line</td>
<td>New England ITC</td>
<td>Maine underwater to Massachusetts</td>
</tr>
<tr>
<td>Bay State Offshore</td>
<td>Anbaric</td>
<td>Deepwater wind farms off Martha’s Vineyard and Block Island to MA, RI</td>
</tr>
<tr>
<td>Northeast Energy Corridor</td>
<td>Irving, Maine, New Brunswick</td>
<td>NB to southern Maine</td>
</tr>
<tr>
<td>Muskrat Falls-Lower Churchill</td>
<td>Nalcor</td>
<td>Newfoundland and Labrador to Maine</td>
</tr>
<tr>
<td>New England Clean Power Link</td>
<td>TDI New England</td>
<td>Quebec to southern Vermont</td>
</tr>
<tr>
<td>Vermont Green Line</td>
<td>VGL, Hydro Quebec, Invenergy</td>
<td>400 MW Plattsburg, N.Y. to New Haven, Vt. Via Lake Champlain</td>
</tr>
<tr>
<td>Maine Yankee site in Wiscasset, Maine, to Boston area</td>
<td>ISO Concept proposal</td>
<td></td>
</tr>
<tr>
<td>Northern Maine into Maine Green Line or other new lines</td>
<td>ISO Concept proposal</td>
<td></td>
</tr>
<tr>
<td>Downeast Maine to Boston area</td>
<td>ISO Concept proposal</td>
<td></td>
</tr>
</tbody>
</table>

This list is updated every month, along with the list of pending power plant proposals needing to interconnect to the grid, at http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue. For developer confidentiality, the ISO does not name sponsors or specific projects, but they generally can be deduced from the origin and termination points listed for the proposed projects. Before 2015, far more projects were listed in the interconnection queue, but in 2015, the ISO raised fees for applying for interconnection and having technical issues studied and identified by its experts to about $250,000. This had the effect of eliminating the most speculative transmission projects from the list, leaving those with the most realistic chance of obtaining funding in the planning queue.

The transmission proposal that has so far drawn the most visibility and controversy is the Eversource/Hydro Quebec (HQ) Northern Pass, a $1.6 billion, 192-mile line, with 60 miles buried. New Hampshire legislators voted in 2012 to ban the use of eminent domain by Northern Pass to assemble rights-of-way for the line, although Northern Pass leaders said they never planned to seize land for the project and would pursue only paths with support from landowners. Northern Pass unveiled a revised route in June 2013 putting more of the route along state and local roadways and reducing the number of affected private landowners from 186 to 31.

In the spring of 2016 the New Hampshire Site Evaluation Committee delayed its deadline for deciding on the project until September 30, 2017, to give opponents more time to respond to the project. It’s unclear at this writing whether Eversource will still be able to meet its original goal of having the line in service beginning in May 2019. More information about the status of Northern Pass may be found at http://www.nhsec.nh.gov/projects/2015-06/2015-06.htm.

One aspect of the Northern Pass plan designed to reduce public controversy is its use of a relatively new kind of funding mechanism called a “delivery commitment” rather than a traditional “power purchase agreement.” Rather than signing on to commit to buying and paying for a specific amount of electricity, under the Northern Pass process, ratepayers will pay for the cost of the transmission upgrades in proportion to the extent hydro electric exporters meet their projections for selling power, and at specific times. HQ and Eversource have also promised to sell guaranteed minimum levels of power during peak winter and summer hours of demand, and at other hours when wholesale electric prices are at their highest, in order to ensure Northern Pass would be a source of overall downward pressure on New England electric prices. The delivery commitment model is designed to put the financial risk of the project on project proponents, rather than ratepayers. Still, a study issued last year by The Analysis Group, commissioned by the New England Power Generators Association, warned that based on overall market prices and what Hydro Quebec would need to charge to make the project economical factoring in the expense of new transmission, Northern Pass could add $777
million a year to New England ratepayers’ electric bills. Other studies by the Massachusetts Clean Electricity Partnership reject that claim and assert projects like Northern Pass and other new supplies would save New England electric customers money.

A total of $4.8 billion in transmission upgrade proposals, both for reliability and for delivering more renewable energy, are pending before the ISO (2015 Regional System Plan, page 26), on top of $7.2 billion in transmission upgrades constructed and deployed between 2002 and 2015, a total of 634 individual projects. (RSP15 page 21) For reliability upgrades, ratepayers pay for the cost of these transmission projects through a FERC-approved “tariff,” or fee.

Having so much new transmission capacity added to the New England grid has had an effect on ratepayers’ bills: From 2008 to 2015, the average transmission charge added to a customer’s bill nearly doubled, from 0.8 cents per kilowatt hour to 1.5 cents per kilowatt hour. But that investment has paid off in major ways, too. Along the lines of the pipeline expansions some utilities and governors are urging, installation of better transmission capacity has paid off for consumers: Total transmission “congestion” costs – basically, consumers being forced to pay for more expensive power produced closer to home because line connections weren’t big enough to bring in cheaper power produced farther away—fell from $266.6 million in 2005 to $32 million in 2014. Over the course of 2014, consumers in Boston paid just 41 cents per megawatt-hour, or .041 cents per kilowatt-hour, in “locational marginal price” premiums more than the average for the rest of New England electric customers. This was a signal from the market that transmission upgrades have nearly eliminated congestion around Boston. (RSP15 page 86)

FERC’s “Order 1000” that took effect May 18, 2015, required changes in transmission planning and cost-allocation procedures that had been used in New England since 2001. They allow the ISO to seek bids for transmission projects to meet forecast demand more than three years out, as well as transmission projects “to meet public policy objectives” such as increased use of offshore wind. How Order 1000 will be implemented through ISO policies is still being worked out. Transmission funding has also been the subject of state-level consideration, such as Rhode Island legislators evaluating legislation to socialize the cost of grid upgrades for renewable energy projects across all ratepayers.

OPERATIONAL CHALLENGES OF RENEWABLES IN THE GRID—NOT ALL MEGAWATTS ARE CREATED EQUAL

While state policies across the region are encouraging and requiring more use of renewable power, especially wind and solar, ISO New England has had to spend millions of dollars on new technologies and procedures to incorporate the variability of those energy sources into reliable operation of the grid.

In running a six-state power grid, ISO has relied on detailed historical knowledge about typical overall power demands at every hour of every day, based on varying weather conditions, which determine how intense demand will be for air conditioning and refrigeration. With a grid supplied overwhelmingly by steady-running nuclear and coal plants supplemented by combined-cycle gas turbine generation that can be easily dialed up and down minute by minute, matching supply to forecast demand was readily manageable.
The rapid growth of wind and solar energy has thrown complications into matching supply and demand because their output is:

- generally far more variable than a coal or nuclear plan;
- less easily predictable than hydro power driven by river flows that change slowly over days rather than in seconds;
- not able to be dialed up or down like a gas plant.

From a grid-operation perspective, wind and solar actually drive up the need to have gas plants or other sources able to suddenly ramp up or down to offset swings in renewably generated electricity. ISO launched efforts in September 2013 to try to forecast distributed generation growth to help better understand its impact on the need for transmission and conventional generation upgrades. It added a new wind power forecast into scheduling and dispatching power plants to run in 2014, and is adding an upgraded electronic dispatch system incorporating wind and hydro later this year. ISO has also changed the wholesale market to allow wind power owners to submit “negative offer prices”—wind generators essentially paying to move power into the grid, not the other way around. This enables wind turbines to avoid having to shut down during periods they are producing surplus power so they are up and running at times their power is needed and will be purchased at wholesale prices profitable for them. (ISO State of the Grid slide 29)

One indication of the scope of the technological challenge for grid managers of the distributed energy revolution: Massachusetts alone has 40,000 distributed energy facilities (such as rooftop solar installations and small wind turbines) and is now adding 400 more per week, according to state Department of Energy Resources data. Generation by solar photovoltaics in New England is forecast to grow from 900 megawatts in 2014 to 2,400 by 2024, according to the 2016 ISO New England Regional Energy Outlook.

All forms of installed electric generation have what is called a “capacity factor,” or what percentage of the stated “nameplate” maximum capacity can actually be relied on over time for the purposes of grid operation planning. Estimates vary widely about what capacity factors can be assumed for various types of generation. The U.S. Energy Information Administration uses the following capacity factors for units going into service in 2020:

<table>
<thead>
<tr>
<th>Fuel Source</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>90</td>
</tr>
<tr>
<td>Combined-cycle natural gas</td>
<td>87</td>
</tr>
<tr>
<td>Coal</td>
<td>85</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>54</td>
</tr>
<tr>
<td>Offshore wind</td>
<td>38</td>
</tr>
<tr>
<td>Land-based wind</td>
<td>36</td>
</tr>
<tr>
<td>Solar photovoltaic</td>
<td>25</td>
</tr>
</tbody>
</table>

Source: U.S. Energy Information Administration [https://www.eia.gov/forecasts/aeo/electricity_generation.cfm](https://www.eia.gov/forecasts/aeo/electricity_generation.cfm)
As a practical matter, for grid operators, what these numbers mean is that over the course of a year, to get as much power as they can count on from a 1,000-megawatt gas-fired or nuclear power plant, they would need roughly 2,400 megawatts of installed nominal wind capacity or 3,600 megawatts of installed solar photovoltaics. And even then, they would still need to have resources and tactics in place to deal with times when clouds obscured the sun during the day or winds slowed down. For now this typically means having standby capacity from conventional power plants that can be quickly dialed up or down to cover a sudden shortage or burst of output from renewable sources. For the longer term, as explained below, the development of large-scale energy storage technology that can absorb fluctuating renewable energy output and reinject it into the grid when solar or wind are ebbing is considered the transformative innovation required to make renewables the dominant source of grid energy.

While New England’s energy future appears certain to include far more renewably-generated electricity and growth in electric-powered transportation, the U.S. Energy Information Administration still envisions, at a macro level, the country heavily dependent on fossil fuels for a long time. In its Annual Energy Outlook 2016, the EIA noted that petroleum, natural gas and coal made up 81.5 percent of all U.S. energy consumption in 2015. In a projection based on “current laws and policies,” the EIA forecast that share will drop by only five percentage points in the next 20 years, to 76.6 percent in 2040. The EIA forecast qualifies, however that “policy changes or technology breakthroughs that go beyond the trend improvements included in the Reference case could significantly change that projection.”

WHO DECIDES WHAT GETS BUILT, AND HOW? ISO, FERC, STATE REGULATORS, AND INVESTORS’ ROLES

As explained above, billions of dollars worth of new gas pipelines, electric transmission lines, power plants, and offshore and onshore wind farms are all being proposed and built in New England. So who decides what gets built, and how? The high-level answer is: Risk-capital developers, investors, and lenders, guided by technical suggestions from ISO New England about what generation and transmission upgrades the region’s electric power system needs and market signals about where more or cheaper electricity is wanted, all subject to reviews and votes by local siting regulators and the Federal Energy Regulatory Commission (FERC) for projects subject to federal gas and electric regulation.

As a rule, for major interstate energy facilities, FERC is the sole or dominant regulatory authority, but state energy siting boards and local regulatory authorities such as zoning boards often have roles in shaping what gets built, too, by statute or by delegation of authority from FERC. While gas supplies and gas pipelines have, as shown above, a huge impact on the workings of the electric system, ISO New England has no direct control over gas infrastructure. Also, broadly speaking, FERC can give developers of gas pipelines major eminent domain authority to site them, but FERC’s eminent domain authority for electric transmission is limited and not fully established under law.
For ISO New England, besides its day-to-day responsibility operating the power grid and administering wholesale markets, the third major responsibility is power-system planning. Every two year, the ISO updates and publishes a Regional System Plan for the next 10 years. This document, developed by ISO planning professionals working in a robust stakeholder-engagement process, aims to forecast where electric demand is growing and identify weak links in the power grid that need upgrading, both generation and transmission. The process takes into account an evaluation of the likelihood of power plants shutting down in the future based on how often they are now getting paid to operate in the competitive market. The process forecasts annual and peak New England power demand for the next 10 years and what combination of generating capacity, transmission, and “demand resources”—or the ability to get customers to curtail their power usage by agreed-upon levels when the grid is facing peak demand—are needed to meet “defined system needs.” The most recent plan, which totals 211 pages, was made public on November 5, 2015, and is available at http://www.iso-ne.com/system-planning/system-plans-studies/rsp.

The Regional System Plan report is highly specific about where grid managers see the need for new transmission lines or power plants. It can serve as a road map for energy investors looking to assess where to propose and finance new capacity. The 2015 Regional System plan, for example, projected a need for new power generating capacity near the existing coal- and oil-fired Brayton Point plant in Somerset, Massachusetts, that will be shutting down on June 1, 2017, and in Tiverton and Portsmouth, Rhode Island, and 100 megawatts of new capacity on Cape Cod, which is likely to be met by NRG’s plans to repower the Canal generating station in Sandwich, Massachusetts, with gas-fueled generators. New generation in southeastern New England, the ISO says, “would provide the greatest reliability benefit” for overall regional needs.

Informed by the Regional System Plan, private-sector investors will develop proposals to construct power plants in areas where they are needed, will get “dispatched” to run enough to make them economical, and can clear local regulatory and political approvals. Projects also need to enter the ISO’s “interconnection queue” and be evaluated by grid engineers to ensure that the plants can be safely connected to the existing grid, and what kind of grid modifications new plant owners may be required to pay for to accommodate them.

The Regional System Plan is developed under the guidance of a Planning Advisory Committee (PAC). “Any entity can designate a member to the PAC” by emailing the PAC secretary, the ISO explains, and that includes not just energy-industry companies but governments, local communities, energy customers, and regional associations such as the New England States Committee on Electricity (NESCOE) and the New England Conference of Public Utilities Commissioners (NECPUC). Some information reviewed in forming the Regional System Plan is “critical energy infrastructure information” withheld from uncontrolled access because of national security and terrorism concerns.

Besides “reliability upgrades,” the ISO also allows energy companies to propose “elective transmission upgrades”—essentially, privately owned toll roads to deliver power to a specific point on the grid from where it is available. Under FERC Order 1000, the ISO is also developing a process for a third kind of
transmission project: Projects that are designed “to meet public policy objectives” such as greater use of renewable power, or projects to come into service beyond the 36-month timeframe of ISO’s usual system-reliability forecasts.

A critical approval for power plants and transmission upgrades is completion of an “interconnection study” by ISO engineers and approval of the project to enter the regional “interconnection queue.” This is a technical analysis concluding that a power plant or transmission line can safely be attached to the existing grid, and identifying which capacity or safety upgrades—sometimes running into the millions of dollars—the project proponent may be required to pay for to ensure the grid would function properly and could handle various contingencies and breakdowns once the new unit has been added.

One of the last key steps in this process of going from proposal to approved reality is successful participation in the ISO’s annual “Forward Capacity Auction” (FCA). This is one of the two main wholesale markets administered by the ISO, the second being the hour-to-hour wholesale electricity market described earlier. The Forward Capacity market was established a decade ago to establish a value for keeping power plants available, regardless of how much power they wind up being called to produce, so that short-term swings in the price of natural gas, oil, or coal, or other factors would not drive permanently out of operation billions of dollars in long-term power generating capacity. (One way to think of the energy and forward capacity markets is to think of a supermarket that makes a certain amount of money for the volume of groceries it sells, but also can compete to get a monthly payment just for maintaining a store, loading docks, refrigerators, freezers, and staff to be available to sell groceries in the first place. The forward capacity market helps prevent, in this metaphor, a few bad months of business from shutting down a supermarket forever).

Generators compete each year in a forward capacity auction that establishes a yearly price for them to be paid, starting about 40 months from the date of the auction, for maintaining their plants as available to be turned on to supply the grid. This price is ultimately added to the electric bills all New England customers pay. ISO New England’s forward capacity markets also add a second kind of incentive unique to brand-new plants to encourage construction of new generation: A voluntary guaranteed minimum capacity price for up to seven years after a unit goes into service, providing a guaranteed income stream to investors. (New plant builders can ask for a guaranteed price for up to seven years but may also elect to begin competing in the annual forward capacity auction sooner than that if they conclude they can get a better price than the seven-year guaranteed price.) The ISO issues every January “expressions of interest” for new power generation capacity, and reviews respondents’ submissions to evaluate how solid their plans and finances are. If they meet objective ISO tests, the following February, 13 months later, they can compete in the forward capacity auction.

The FCA is a so-called descending-clock auction. The ISO identifies how much capacity it will need to meet demand, plus a safety cushion, and solicits a first round of bidding per megawatt-year. This will normally prompt bids for thousands of megawatts of capacity more than the needed level. Then the ISO gradually lowers its offered price, inducing generators and suppliers of capacity who had been holding out for a higher price to withdraw their offers, until finally there is a stack of bids equal to the capacity the ISO identifies as needed. Every participant then gets paid that price, much like how in the hourly wholesale market every active generator is paid the price offered by the last marginal unit needed to operate to meet demand.

Energy efficiency programs and demand response can be bid into the capacity auction as if they were power plants and get paid the same amount. In the case of demand response and efficiency, they are helping ISO meet capacity needs by lowering demand as generators provide supply.
Broadly speaking, most New England power plant owners now make about 30 to 40 percent of their total revenue from capacity payments, and about 60 to 70 percent from production and sales of electricity for the hourly wholesale market, according to the New England Power Generators Association. The ISO also runs small, specialized auctions that pay generation units for special characteristics like being available to maintain voltage and frequency in the grid and for “quick start” capabilities to be fired up in 10 minutes or less in the case of a major power outage.

Once a power plant or merchant transmission line project has cleared the ISO interconnection review and forward capacity auction and received state and local approvals, it still may not go forward if investors believe the economics of the project have changed and it’s no longer a good investment, or if the parent company’s balance sheet or financial condition has changed significantly since the project was first proposed. However, there are significant financial penalties the ISO will levy on participants in the capacity market who clear the auction but later withdraw from the market.

THE FEDERAL ENERGY REGULATORY COMMISSION AND STATES’ ROLES

As a rule, any big electric transmission proposal serving the interstate wholesale market or large gas pipeline or gas facility will need to be approved by FERC. (What was originally the Federal Power Commission created in 1920 became the FERC in 1977, with its authorities and powers most significantly redrawn under the Energy Policy Act of 2005).

Under federal law, FERC regulates:

- the transmission and wholesale sale of electricity in interstate commerce, with power to ensure that rates “are just, reasonable, and not unduly discriminatory or preferential.”

- the transmission and sale of natural gas for interstate commerce and authority to set “just and reasonable” rates.

- siting of interstate natural gas pipelines, LNG facilities, and gas storage.

- licensing and inspecting of 1,600 hydroelectric projects and all new hydro proposals.

- accounting and financial regulation for regulated energy companies.

- and ensuring the reliability of the high-voltage electric transmission system. (FERC has authorized the North American Electric Reliability Council, known as NERC, to fulfill this oversight responsibility and under the 2005 Energy Act in 2006 made NERC an “Electric Reliability Organization” as mandated by the 2005 energy act, with authority to levy fines of $1 million per violation per day on utilities and transmission companies. The Northeast Power Coordinating Council, NPCC, is the regional affiliate of NERC through which local electric transmission companies’ compliance with reliability standards is enforced.

FERC has wide-ranging and longstanding eminent domain authority to get natural gas pipelines and facilities built, but only limited eminent domain rights for electric transmission. Under the 2005 Energy Act, FERC may consider and issue a permit for electric transmission projects, including the right of eminent domain for right-of-way assembly, if a state has withheld approval for the project for more than a year. How in practice this authority would be executed has not been established.

Frequently, deciding which facilities are subject to federal regulatory authority is complex. FERC has a 7-part test, augmented by decades of administrative proceedings and case law, to identify what
is a “transmission” line subject to federal regulation and what is a “distribution” line subject to state utility commission regulation. Under the National Environmental Policy Act, FERC is also mandated to consider “non-wire” alternatives to transmission lines such as added local generating capacity, demand management, and energy storage technology.

On a big energy project subject to FERC regulation, FERC will typically still first look to and prefer to have state siting boards and city and town zoning boards review and vote on issues such as the routes of pipelines and power lines and locations of switchyards and pump stations. Project proponents can almost always still override local opposition by going to FERC, but it adds long delays to the process, and FERC will typically direct proponents to make or have attempted to make a good-faith effort to win local approval before turning to federal preemption. FERC will also have the U.S. Army Corps of Engineers review and rule on wetlands issues raised by electric and gas proposals, and the U.S. Fish and Wildlife Service on whether proposals would illegally jeopardize habitat for endangered species. FERC gets funding for its operating budget from assessments on the companies it regulates, not Congress. The venue for appealing FERC’s decisions is filing suit in federal court.

FERC is the chief regulator of natural gas pipelines and associated equipment, as well as LNG terminals, under the Natural Gas Act of 1938. FERC’s standard for approving a gas line or facility is that the applicant is “able and willing properly” to build and operate the project and “construction...is or will be required by the present or future public convenience and necessity.” Part of establishing to FERC the necessity for the project is having signed contracts from subscribers for the gas, either gas utilities or power plants or industrial customers.

In its approval, FERC may attach “such reasonable terms and conditions as the public convenience and necessity may require.” The Natural Gas Act has been interpreted as conferring access to rights of way by eminent domain for holders of certificates of public necessity, through claims made through state and federal court. For example, in the spring of 2016, a Berkshire Superior Court judge in Massachusetts ruled that under the Federal Gas Act, Kinder Morgan’s Tennessee Gas did not need the Massachusetts Legislature to approve its gaining access to a state forest to build part of its Connecticut Expansion 13.5-mile gas loop.

AccessNortheastEnergy.com describes the pipeline approval process as typically involving:

1. A pre-filing notification with FERC that an energy company or developer wants to propose a new facility.

2. “Scoping” by the FERC to identify environmental and logistical issues and stakeholders to reach out to.

3. A formal application to the FERC for a certificate.

4. FERC publishes a notice of the application.

5. Additional stakeholder engagement and discussion.
6. FERC determines whether an Environmental Assessment or Environmental Impact Statement will be required, including potential involvement by the U.S. Army Corps of Engineers on wetlands issues and Fish and Wildlife on Endangered Species.

7. FERC responds to comments.

8. FERC issues a certificate and order approving the project and laying out necessary conditions.

Those interested in following the progress of projects pending before FERC can register for access to all filings (by docket number) at www.ferc.gov/docs-filing/efiling.asp. On any project, interested parties may file to gain “intervenor” status and have all new filings on a project forwarded to them (provided they share all filings they make to others) through www.ferc.gov/help/how-to/intervene.asp.

Ultimately, once a power plant, electric transmission line, gas pipeline, or other energy project has cleared FERC and local approvals, and in the case of electric projects has satisfied ISO requirements for being connected to the grid, what gets built still turns heavily on bankers and investors, and what they consider economically viable. Major gas and electric projects regularly get to the starting line but then are delayed, withdrawn, or accelerated because of changing wholesale prices for gas or electricity or other unexpected factors.

THE FUTURE OF NUCLEAR POWER IN NEW ENGLAND

Many in New England energy markets were stunned when Entergy announced in October 2015 it would close down the 685-megawatt Pilgrim nuclear station in Plymouth, Massachusetts, by no later than June 2019 because it was uneconomical to run and comply with the cost of mandated safety upgrades. Coming just 10 months after the shutdown of Vermont Yankee, and after the closures of four other nuclear plants in the region—Connecticut Yankee, Maine Yankee, Yankee Atomic, and the Millstone 1 unit at the three-reactor complex in Connecticut—the Pilgrim announcement raised concerns about the future of the remaining nuclear units: Millstone 2 and 3 in Connecticut and Seabrook in New Hampshire. [Seabrook’s Nuclear Regulatory Commission operating license doesn’t expire until March 15, 2030. Licenses for Millstone 2 and 3 expire July 31, 2035, and November 25, 2045, respectively (RSP15 page 155)]

For all the concerns they raise in some quarters about safety, operations, and disposal of radioactive waste, nuclear power units are major contributors to states’ meeting 2020 goals for carbon emissions. These are large sources of non-carbon-emitting energy for the region: Seabrook produces up to 1,295 megawatts of power, Millstone 2 884 MW, and Millstone 3 1,227 MW (ISO RSP 15 figure 2.2 page 155) It would take hundreds of thousands of acres of solar panels and wind farms to replace the energy produced by the three nuclear plants. The uptick in New England carbon emissions from electricity generation in 2014 has been attributed to the use of oil in gas-fired plants but also to a significant extent the shutdown of Vermont Yankee, forcing more use of gas-fired plants to meet New England’s electric demand. In August 2016, New York adopted a system of “zero emission credits,” or ZECs, and ratepayer-funded subsidies to three upstate nuclear plants to recognize their value as
producers of non-fossil-fuel electricity as the state pursues 40 percent reductions in emissions by 2030. Some participants in New England energy markets are advocating for consideration of ZECs or other financial supports for nuclear power in this region.

Beyond issues of nuclear’s future in New England, the nuclear industry also continues to express frustration with the lack of a long-promised national solution to the issue of radioactive waste. Under the Nuclear Waste Policy Act, ratepayers paid tens of billions of dollars into a federal nuclear waste fund but officials have blocked permanent nuclear waste facilities since the 1990s, including a planned facility at Yucca Mountain in Nevada.

As a result, radioactive waste is stored locally at “independent spent fuel storage installations,” including at the region’s decommissioned reactor sites with 43 dry storage casks at Connecticut Yankee in Haddam Neck; 64 casks at Maine Yankee in Wiscasset; and 16 casks at Yankee Atomic in Rowe, Massachusetts. The single-asset utility companies that own these facilities have sued the federal government for failing to remove the spent nuclear fuel and “Greater Than Class C” waste to the promised permanent disposal site. These lawsuits have thus far yielded over $470 million in three rounds of damages to offset the cost of continued waste storage at these sites (see www.3yankees.com). It’s unclear whether Congress and the White House will agree on the permanent national nuclear waste storage site called for by the 1982 Nuclear Waste Policy Act. Proposals are moving forward for consolidated interim storage facilities in western Texas and New Mexico that could become homes, perhaps by 2021, to waste now stored at the permanently shut-down plant sites in New England. While the ongoing lawsuits against the federal government have recovered most, but not all, of the costs to ratepayers for safely storing and monitoring dozens of concrete casks with radioactive waste at the sites, electric customers are paying millions for delays and the cost of litigation. It also amounts to taxpayers paying for a kind of safe long-term storage that is far more expensive than larger-scale centralized storage on a national scale would be.

WHAT ARE “SOLAR NET METERING CAPS” AND WHY ARE THEY SUCH A HOT ISSUE IN SO MANY NEW ENGLAND STATES?

For all the environmental benefits, job creation, and consumer appeal of solar energy, solar also creates operational and financial complexity for utilities. Sudden changes in cloud cover may lead to a burst of surplus electricity suddenly pouring from a home back into the neighborhood power grid—or a sudden burst in demand for power from the grid when the sun goes behind a thick cloud. Likewise, because almost all utilities charge consumers for power delivery strictly according to how much they consume—not a fixed monthly fee to be hooked up to the grid plus a variable fee for power used—people and businesses whose solar installations produce more power than they use over the course of a year will see their cost of being connected to the grid go to $0, or even make a net profit from the solar power their panels generate, even though they continue to get power from the grid at night and on dark days and enjoy the benefits of a backup grid connection in case of solar panel malfunctions.

For these reasons, electric regulators have approved what are called “net metering caps” to control the number of solar installations, for the sake of limiting variable solar flows that complicate grid operations and to maintain a base of non-solar-deploying ratepayers to equitably share the cost of maintaining the electric grid and distribution lines.

“Net metering” is a technical term that effectively means: Feeding or selling electricity your solar panels generated that you did not consume back into the power grid. One of the more controversial issues with net metering has been where to set the financial credit that solar panel owners get for the electricity they sell back to the grid. Should it be valued at the retail price for electricity, so that
panel owners get a $1-for-$1 bill offset for the kilowatt hours they feed back into the grid? Or should a discount be applied to the credit that panel owners get so those with big enough, properly situated homes where solar arrays can work don’t get an unfair subsidy from the rest of the utility’s non-solar consumers? How much should solar panel owners’ reimbursement for generated power be discounted to account for the value of the grid service and backup connection they continue to have?

In recent years, every New England state has grappled with where to set a net-metering cap and what to include under it. Massachusetts legislators have also exempted all residential-scale solar installations from restrictions under net metering. Maine Governor Paul LePage vetoed a net metering bill in late April 2016, saying it was an unfair subsidy by all ratepayers to affluent owners of large homes who could afford to buy solar panels. Vermont in 2013 set a cap of 15 percent of peak electric demand for solar net metering and has hit it. The Public Service Board is working on revising net metering rules by January 2017. New Hampshire is well under its current statewide net metering cap, but legislation has already been enacted this spring to increase it by 50 percent.

New England states had the following amounts of solar photovoltaic generating capacity installed as of December 2015, according to the ISO New England Distributed Generation Forecast Working Group:

<table>
<thead>
<tr>
<th>State</th>
<th>“Nameplate” Solar PV Installed in MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>158.73</td>
</tr>
<tr>
<td>ME</td>
<td>12.43</td>
</tr>
<tr>
<td>MA</td>
<td>855.30</td>
</tr>
<tr>
<td>NH</td>
<td>18.53</td>
</tr>
<tr>
<td>RI</td>
<td>21.51</td>
</tr>
<tr>
<td>VT</td>
<td>108.27</td>
</tr>
</tbody>
</table>

Under the Massachusetts Green Communities Act, Bay State utilities were given an exemption from the 1997 restructuring law when it came to solar power generation. The state’s biggest utility, National Grid, was authorized to own up to 35 megawatts of solar electric generation capacity—about 20 megawatts has been installed so far—in hopes of providing a subsidy to the development of the market and because utilities would know the most feasible locations for incorporating potentially highly variable solar-generated electricity into their distribution networks.

**DEMAND RESPONSE/ENERGY EFFICIENCY**

As explained above, because of the economics of electricity in periods of peak demand when grid operators have to pay whatever providers are bidding in order to prevent rolling blackouts, about 1 percent of all hours in the year drive 8 percent of New England’s total electric costs, and the 10 percent of top-cost hours in the year account for fully 40 percent of the regional electric bill.

“Demand response” is a system for sharply lowering overall annual electric costs by giving financial incentives to DR participants to consume less power in key designated hours. Currently, New England is well ahead of the rest of the country in having the tools and agreements in place to use demand...
response to shave peak demand, which in turn can have big impacts on the overall annual cost of electricity. During a summer heatwave when demand is spiking, ISO-New England can activate measures to reduce more than 10 percent of peak-period demand, such as customers agreeing to shut down industrial facilities and lighting and to raise temperatures inside refrigerators and set-points for air conditioning. Demand response efforts are often implemented through companies like EnerNOC of Boston that line up subscribers and manage the actual reduction of power usage at their facilities. Implementation of demand response has also become very geographically targeted. ISO New England now uses 19 “dispatch zones” within which it can order up DR measures. A January 25, 2016, ruling by the U.S. Supreme Court affirmed the Federal Energy Regulatory Commission’s power to set payments to providers of demand response for the value of averted demand for electricity. FERC is working towards a June 1, 2018, target date for updating protocols for implementing demand response in wholesale energy markets.

Energy efficiency can also be bid into the ISO’s annual capacity auction and paid for as a form of negative generation, relative to an historic baseload. Currently, the ISO system pays for 1,500 megawatts worth of energy efficiency that lowers the need for generation, and that number is forecast to jump to 3,600 megawatts by 2024, according to the ISO’s 2016 Regional Energy Outlook.

Thanks in significant measure to RGGI proceeds paying for efficiency measures and measures by the ISO to pay efficiency programs to save energy just as power plants are paid to make it, New England states all ranked high in the American Council for an Energy Efficient Economy’s 2014 scorecard ranking states on their energy efficiency efforts: Massachusetts 1, Vermont and Rhode Island tied for 3, Connecticut 6, Maine 16, and New Hampshire 22. New England states collectively spent $2.3 billion on energy efficiency in 2009-12, according to ISO New England, and the ISO estimates they will spend another $6.3 billion from 2017 to 2023.

Overall, while the ISO predicts demand for electricity will grow about 1 percent a year across the region over the next decade, its forecast for energy efficiency and demand response growth is much faster:

<table>
<thead>
<tr>
<th>State</th>
<th>Compound Annual Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>8.7%</td>
</tr>
<tr>
<td>CT</td>
<td>6.4%</td>
</tr>
<tr>
<td>ME</td>
<td>5.9%</td>
</tr>
<tr>
<td>MA</td>
<td>10.7%</td>
</tr>
<tr>
<td>NH</td>
<td>7.0%</td>
</tr>
<tr>
<td>RI</td>
<td>9.5%</td>
</tr>
<tr>
<td>VT</td>
<td>6.0%</td>
</tr>
</tbody>
</table>

ENERGY STORAGE AND RENEWABLE ENERGY GROWTH

One key way to make highly variable wind and solar energy more reliable and effective as a source of electricity will be through more widespread use of “energy storage” devices that capture surplus renewables when they are abundant to release electricity at night or when the wind stops blowing.

On May 4, 2016, Green Mountain Power, which serves 265,000 customers in Vermont, announced it had become the first U.S. utility to perform customer installations of Tesla Powerwall home battery systems. The devices allow people who own solar panels or wind turbines to use them to charge up the Powerwalls, then draw power from the units for up to 4 to 6 hours to run their homes or businesses when they have insufficient or no power from their solar or wind units. The Powerwall also becomes a way to keep lights and appliances on during power outages, or to lower costs at peak summer demand hours by switching customers from grid power to Powerwall power. Green Mountain offers plans under which customers can lease the units for about $37.50 a month with no up-front cost; buy them outright for $6,501; and as a third option, buy them for $6,501 and get a monthly bill credit of $31.76 if they are willing to let GMP use some of the power in the device to feed other customers on the grid. (http://products.greenmountainpower.com/product/tesla-powerwall/)

In Massachusetts, the Department of Energy Resources is completing a $10 million study of “energy storage” technologies to reduce the cost of electricity at periods of peak demand. The department has consulted with more than 300 technology companies, utilities, and other organizations. Some of the technologies being evaluated in this study include: Pumped hydro, compressed air, energy flywheel, batteries, molten salt, batteries, chilled water, ice, thermochemical, SMES superconductors, and fuel cells. GTM research indicates that from 2016 to 2020, U.S. energy storage will grow by 500 percent to 1,662 megawatts of capacity. Why energy storage could have such a huge impact on the grid goes back to the numbers that just 1 percent of all hours of electric consumption in New England account for 8 percent of the region’s total cost of electricity, and the top 10 percent of demand hours (typically summer hot spells, winter afternoons, or periods when grid managers are coping with a supply failure) account for 40 percent of electric spending. The Massachusetts DOER study is drilling down to look at 1,497 specific locations throughout the state’s power grid to determine where would be the most advantageous and cost-effective places to add energy storage. (Source: Judith Judson presentation to Restructuring Roundtable, May 18, 2016 in Boston)

Massachusetts’ August 2016 energy law also directs the Department of Energy Resources to determine by the end of 2016 “whether to set appropriate targets for electric companies to procure viable and cost-effective energy storage systems to be achieved by Jan. 1, 2020.” The department would be required to set plans for Eversource, National Grid, and Unitil to buy and deploy energy storage systems by July 2017.
CONCLUSION

New England comprises six states with six energy policies, generally similar although not completely aligned. But New England gets its electricity from one single electric grid and its gas from a highly interconnected gas network. The natural gas network and market has become, in turn, deeply interconnected to the electric grid operationally and to the wholesale electric market as well.

What New England voters and policymakers have made clear is that we want reliable, affordable, and environmentally friendly energy supplies and networks for transmitting energy. The challenge is that in the near term, it’s unlikely to impossible that New England will get all three. Trade-offs will have to be made, and policymakers will have to understand what those trade-offs entail and the costs involved, in dollars, in environmental impacts, and in our expectations of the reliability of our power supplies.

Until and unless utility-scale devices and systems for storing energy are widely affordable and reliable, renewable sources like on- and off-shore wind and solar will need backup from gas-fired power plants, nuclear power, and perhaps hydroelectric power. Because of the long distances between where most New Englanders live, work, and use power and where wind and hydro power are most abundant in the region and neighboring Canada, using more “green” power will require expensive transmission lines most New Englanders have made clear they don’t want to see on their landscapes—or underground and undersea transmission lines that are far more costly and challenging to maintain than above-ground lines. Because of the combination of environmental and economic forces that have left natural gas the default primary source of new power generation since the 1990s, policymakers will have to evaluate conflicting forecasts to determine what level of additional gas supply infrastructure is needed, and how much the risk can be eliminated that New England ever runs short of gas for heat and power—at what price and at what cost-benefit ratio.

Additionally, as shown in the diagram on the right, every policy-driven decision to add some new source of energy outside the workings of a purely free market will create winners, losers, savings, and costs. Adding more large-scale hydro or wind will affect the economics of gas-fired generation and nuclear power. Incentives for more energy conservation and demand response will change the need for power, how it is generated, and how much it costs in the 10 percent of hours of the year that account for 40 percent of all regional spending on electricity. The overall mix of gas, nuclear, wind, and hydro used to meet New England’s power needs will affect how well the six states do meeting their 2020, 2035, and 2050 emissions mandates.

New England has a much more complicated challenge in resolving its environmental and energy issues than economic competitor areas such as California, New York and Texas, which are all single states with single state power grid operators. Impacts in one part of those states may be more easily sold, politically, as benefiting all residents of that same state with lower costs and more reliable, more “green” power. But New England faces the challenge that the most affordable systems for delivering more green power to the more urbanized states of Connecticut, Massachusetts, and Rhode Island could most likely require more overhead lines that would be considered blight on the landscape in Maine, New Hampshire, and Vermont. Burying transmission lines underground or offshore may be politically expedient or necessary in northern New England, but that adds huge expense to electric bills for all New Englanders. Another manifestation of the intra-regional challenge of locating desired energy facilities and supplies came this spring when a gas pipeline that would have significantly increased supplies to New Hampshire and Maine and reduce huge economic pressures on industrial and manufacturing companies, Kinder Morgan’s Northeast Direct, got withdrawn in the face of intense opposition in Massachusetts. At the same time, the Massachusetts Supreme Judicial Court’s rejection of an electric-utility funding tariff for gas capacity expansion has thrown into question the...
This is the Energy Future We Want

1. Energy that is affordable and reliable: gas, oil, coal, nuclear. To make it “green” as well would require billions for carbon capture and pollution reduction and many environmentalists will always oppose fossil fuels and nuclear.

2. To be reliable wind and solar need billions for transmission from where the resources are to where demand is in New England, smart grid backup, standby gas and nuclear capacity to offset sudden drops in renewable output, and utility-scale storage.

3. To be affordable we need the cost of generation to plunge further to offset the transmission and reliability premium and/or for the cost of energy storage to follow a Moore’s Law curve of rapidly declining costs.
The New England Council believes it is important and valuable for legislators and policymakers to seek a holistic understanding of how each decision about our energy future can affect all the others. Expanding a gas pipeline or a hydroelectric transmission line will affect the economics of nuclear power and offshore wind. What mix of energy is economical to produce will, in turn, affect whether states reach their greenhouse gas mandates and environmental goals. Increasing use of local renewables may reduce energy costs, emissions, and the need for gas in the long term but add significant costs and complexity to grid operations in the near term.

At hundreds of meetings every year involving thousands of stakeholders, ISO-New England works to achieve a regional power grid that is reliable, affordable, and responsive to the environmental and energy policy goals adopted by the six New England states. Policymakers around New England would do well to keep asking how the operations and governance of the ISO can continue to be perfected to meet the reliable-affordable-green triple mandate for electricity, and how much states may have to agree on and pursue ad-hoc initiatives such as the Connecticut-Massachusetts-Rhode Island joint RFP process for new clean energy supply. Federal legislation may well prove needed—and meriting New Englanders’ support—to clarify and expand the role of the ISO as a “regional transmission organization” that can also deliver on the region’s desired environmental and policy outcomes for energy.

We would also encourage leaders and policymakers in all six states to consider questions such as:

- How much could New England benefit from harmonizing renewable portfolio standards and 2050 greenhouse gas emissions laws while respecting local values and policy preferences?
- What would be the advantages to and challenges of expanding the existing Regional Greenhouse Gas Initiative—further lowering allowable carbon emissions to attach a higher value to reducing them—as a major or even primary strategy to help all six states meet their 2020 and 2050 carbon and climate goals?
- Should New England consider some form of non-carbon-emitting energy credits, as New York and other jurisdictions are considering, or other measures to protect the ongoing operation of the Seabrook and Millstone nuclear units to keep the region on track to meeting its carbon-emission mandates and to maintain diversity and resiliency in our fuel supply?
- How can better interstate cooperation and incentives help ensure transmission projects needed in some states to meet the green-energy needs of other states are acceptable and approvable locally?
- How can the six New England states and energy stakeholders support and accelerate...
modernizing power grid technology and procedures to accommodate the rapid and desired expansion of variable renewable energy sources?

• Amid all the conflicting reports, and the negative court ruling in Massachusetts, how much more natural gas delivery infrastructure does New England need? How should it be paid for? What changes in law or regulation could create stronger incentives for gas-fired power plant owners to line up firm supplies in winter months? Will the current policy of paying plants to store and burn oil as a backup fuel remain environmentally and economically acceptable?

• Recognizing that there may be no limit on how much we would have to pay to have a perfect power system that never failed: How do we decide what is enough but not too much winter energy reliability, at what acceptable price in cost and emissions impact, to ensure we keep the lights on and heat flowing in the most dire cold snap? How much more could be done for winter “demand response” to avoid a looming crisis, comparable to what’s been done to allow New England to shave its summer peak electric demand by up to 10 percent if needed?

Back in 2001, The New England Council commissioned a study on energy issues by Polestar Communications & Strategic Analysis. It included a key observation that is as true in 2016 as it was 15 years ago: “A more coordinated and integrated regional public policy voice on energy, environmental, and economic policy is critical if the region is to maintain and enhance its competitive position.”

New England is an excellent place to live, learn, and do business. We are also at the end of the conventional energy pipeline, and so we pay much higher costs for electricity and natural gas than the rest of the country. That cost premium has huge implications for jobs, growth, and our ongoing economic competitiveness nationally and globally. New England also has enormous renewable energy potential, including offshore wind, and a long history of policy and technology innovations to meet big challenges like the one we now face of forging a regional energy supply that is reliable, more affordable, and works to meet all six states’ climate objectives and mandates.

The New England Council looks forward to continuing to be an advocate for reliable, affordable, and environmentally sound energy for our region. The council also remains strongly committed to serving as a leader, convener, and supporter of the intra-regional discussions and negotiations—and the national legislation and policies—that get to the best energy future possible for all New Englanders.
## UPCOMING DATES

### 2017

<table>
<thead>
<tr>
<th>Month</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>Vermont adopts new solar net-metering cap</td>
</tr>
<tr>
<td>June 1</td>
<td>1,535 megawatt Brayton Point coal and oil/gas units to shut down</td>
</tr>
<tr>
<td>June 30</td>
<td>692-megawatt Footprint Power Salem Harbor (MA) generator scheduled to go in-service</td>
</tr>
<tr>
<td>September 30</td>
<td>New Hampshire Site Evaluation Committee deadline for ruling on Northern Pass electric transmission project</td>
</tr>
<tr>
<td>November</td>
<td>Targeted in-service date for Spectra Algonquin Intermediate Market (AIM) gas pipeline expansion</td>
</tr>
</tbody>
</table>

### 2018

<table>
<thead>
<tr>
<th>Month</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>April</td>
<td>FERC deadline for relicensing Connecticut River hydroelectric units</td>
</tr>
<tr>
<td>April-June</td>
<td>400-megawatt Medway (MA) peaker goes into service</td>
</tr>
<tr>
<td>June 1</td>
<td>Current planned date for FERC to complete integration of “demand response” initiatives into wholesale electric markets as a result of January 25, 2016, Supreme Court ruling</td>
</tr>
<tr>
<td>June 1</td>
<td>In-service date for Bridgeport Harbor 6 in Connecticut, 475 megawatts...90 MW Wallingford 6/7 in Connecticut</td>
</tr>
<tr>
<td>December 1</td>
<td>In-service date for 785 MW Towantic gas power plant in Connecticut</td>
</tr>
<tr>
<td>4Q</td>
<td>“Initial in-service” target date for Spectra Access Northeast Energy pipeline upgrade as per SpectraEnergy.com</td>
</tr>
</tbody>
</table>

### 2019

<table>
<thead>
<tr>
<th>Month</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>May 31</td>
<td>685 MW Pilgrim nuclear power plant in Plymouth, Massachusetts, to cease operation</td>
</tr>
<tr>
<td>Mid-year</td>
<td>Expected new gas units online in Sandwich MA, Burrillville RI, Bridgeport CT</td>
</tr>
<tr>
<td>June 1</td>
<td>Shiller 4/6 coal-fired power plant (NH), 97 megawatts total, projected to close</td>
</tr>
<tr>
<td>June 1</td>
<td>West Medway 1 and 3 (MA) oil units. 111 megawatts total, to close</td>
</tr>
</tbody>
</table>

### 2020

<table>
<thead>
<tr>
<th>Month</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 14</td>
<td>189 MW South Meadow (CT) power plant to close</td>
</tr>
</tbody>
</table>

### 2021

<table>
<thead>
<tr>
<th>Month</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>June 1</td>
<td>West Medway 2 (MA) 53-megawatt oil unit closes</td>
</tr>
</tbody>
</table>

Dates came from ISO New England and Massachusetts Attorney General reports.
ACKNOWLEDGMENTS

In addition to the documents and websites quoted in this report, The New England Council would like to thank representatives of the following organizations for making time for interviews and comments:

Anbaric Power
BAE Systems
Brightfields Development
Bowditch & Dewey
Coalition of Northeastern Governors
DONG Energy
Engie
Eversource
Freedom Energy Logistics
General Electric
Hydro Quebec
JFS Energy Advisors
Kinder Morgan
Liberty Utilities
Macfarlane Energy
MetroHartford Alliance
National Grid
New England Fuel Institute
New England Power Generators Association
NixonPeabody
Northeast Gas Association
Offshore Wind Massachusetts
Polar Beverages
PretiFlaherty
Prospect Hill Strategies
Providence Chamber of Commerce
Repsol
Spectra Energy
Sprague Energy
Velcro
VoxGlobal
WilmerHale
The Yankee Companies

To maintain its independence and impartiality as the regional wholesale electric market administrator, ISO New England did not comment for this report, but its extensive www.iso-ne.com website, and in particular its 2015 Regional System Plan and 2016 Regional Energy Outlook, were invaluable resources.

ABOUT THE AUTHOR

This report was researched and written on behalf of The New England Council by Peter J. Howe, Senior Advisor at Denterlein Worldwide and former business reporter at The Boston Globe and New England Cable News.