JANUARY 21, 2015

State of the Grid: Managing a System in Transition

ISO on Background

Gordon van Welie
PRESIDENT AND CEO

About the *ISO on Background* Series

- Informal opportunity for media to learn more about trends affecting New England's electricity industry
- Hosted by ISO New England senior management
- Content is **on-the-record**
- Please hold questions until the Q&A session at the end of the presentation
- Presentation and remarks will be posted at www.iso-ne.com>About Us>News and Media>Press Releases

Good morning, everyone. My name is Ellen Foley and I am the Director of Corporate Communications at ISO New England. Today I am joined by Gordon van Welie, president and CEO of ISO New England. We'd like to welcome all of you to our seventh "ISO on Background" session.

We hold these *ISO on Background* informational briefings periodically to provide the media with an informal opportunity to get an in-depth look at the trends affecting New England's electricity industry. Although these sessions are called *ISO on Background,* the content is on the record, and may be quoted and attributed to the speaker.

To be sure that we get through the material in the scheduled time, we'll hold questions until the Q&A session at the end.

I'll go over today's agenda and provide a quick overview of ISO New England, followed by Gordon van Welie, president and chief executive officer, who will describe the state of New England's power grid.

Agenda

11:00-11:10 a.m.	**Welcome; About ISO New England** Ellen Foley, Director, Corporate Communications
11:10-11:50 a.m.	**State of the Power Grid 2015: Managing a System in Transition** Gordon van Welie, President and CEO
11:50-12:15 p.m.	**Question and Answer Session**

The presentation will last about 45 or 50 minutes; then we've set aside about a half-hour for questions from the media.

The presentation and remarks will be posted on the ISO New England website, in the press release section, after the session concludes. The posted presentation will include an appendix of slides that provide more details about some of the topics we'll cover today.

Presentation Overview

- About ISO New England
- State of the Power Grid: Managing a System in Transition
  - Winter operational experiences highlight natural gas dependency, and risks from resource retirements
- Wholesale Energy and Capacity Market Price Signals
- Identifying Risks, Developing Solutions
- Conclusions

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We’ll focus today on the evolution of the resource mix on the New England power grid, and the resulting challenges to maintaining reliability. We’ll explain the role of the wholesale markets and the price signals emerging from the markets; and summarize the region’s infrastructure challenges, some of the steps we’ve taken to address these challenges, and the need for more energy infrastructure in New England.

ABOUT ISO NEW ENGLAND

ISO new england

About ISO New England

- **Regulated by** the Federal Energy Regulatory Commission (FERC)
- **Reliability coordinator** for New England under the North American Electric Reliability Corporation (NERC)
- Nearly two decades of experience **overseeing** New England's restructured electric power system
- **Independent** of companies doing business in the marketplace

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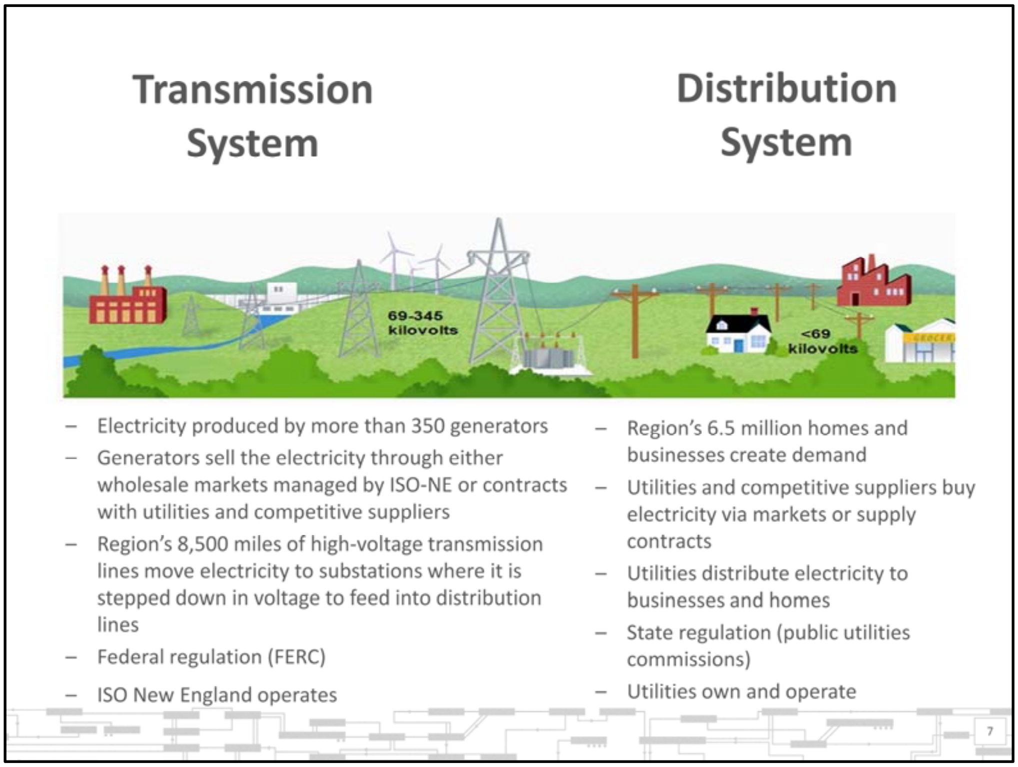
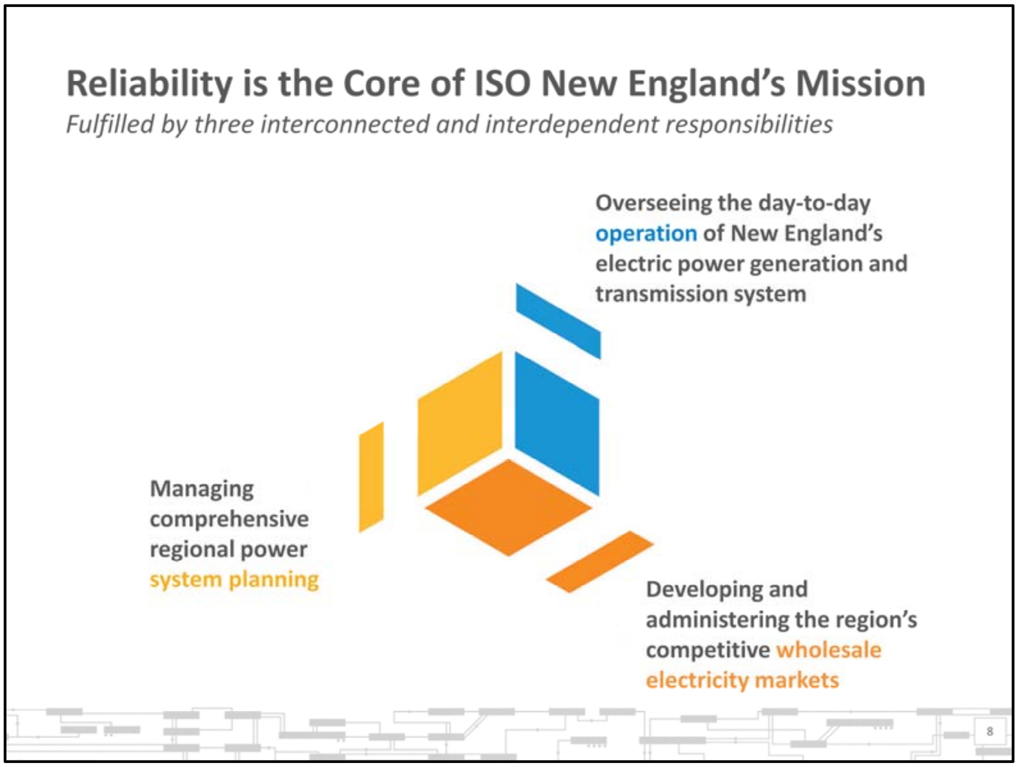
ISO New England, headquartered in western Massachusetts, is the independent, not-for-profit corporation established by the federal government in 1997 to handle three important tasks: operating the high-voltage power system in the six New England states, administering the wholesale electricity markets, and conducting power system planning. A hallmark of the ISO's independence is the fact that employees and management can't have any financial interest in any of the companies doing business in the markets.



This slide highlights the key differences between the transmission and distribution systems.

The transmission side is where wholesale electricity is generated and sent over high-voltage transmission lines to the localities where the distribution system will deliver it to end-users. The wholesale side, where ISO New England operates, is regulated by the Federal Energy Regulatory Commission, or FERC.

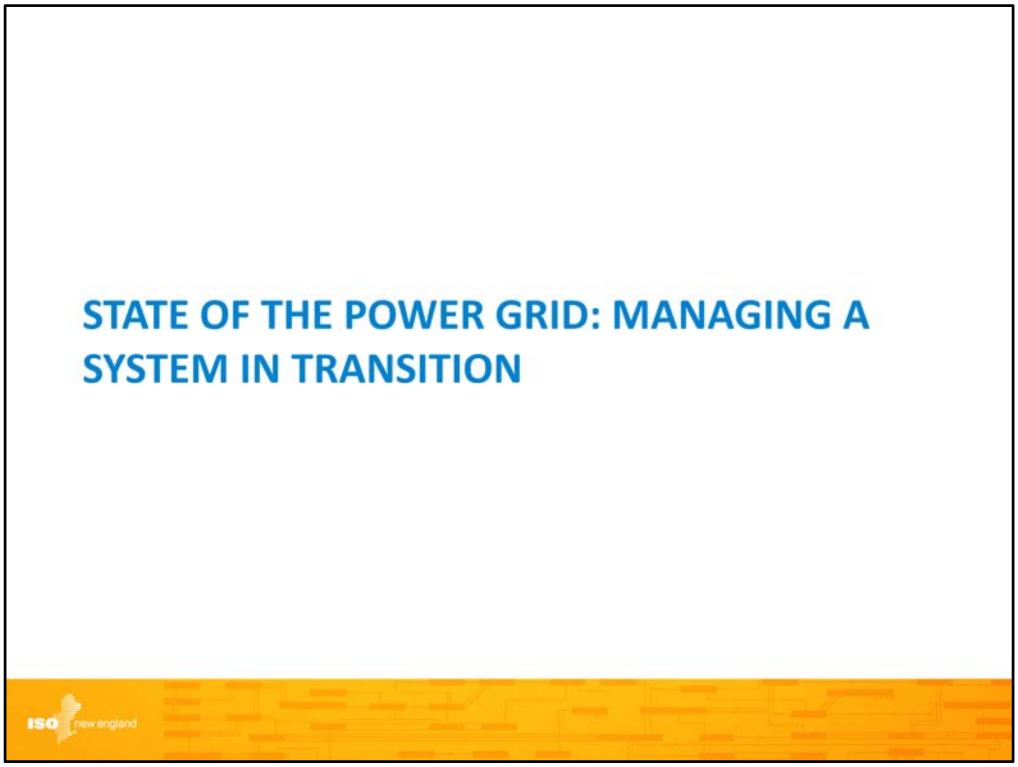
On the distribution side, the high-voltage electricity is stepped down to a lower voltage so it can be delivered to consumers via the wires running along streets and roads. These retail customers get their bills from local utilities, and those bills combine wholesale and retail costs in rates approved by state regulators.



The ISO's primary responsibility is the minute-to-minute, reliable operation of the six-state power grid. The ISO doesn't own any transmission or distribution lines or power plants. You can think of us like an air traffic controller, directing power generation across New England. We also administer the wholesale electricity markets, somewhat like a stock exchange. The ISO itself does not buy or sell electricity, and we don't make money in these markets. Our purpose is to run the markets so they are fair, efficient, and competitive.

To ensure that the region has the resources required to serve future power system and consumer needs, our comprehensive planning process looks ten years into the future.

Today, Gordon van Welie, president and CEO of ISO New England, will describe the state of New England's power grid, the transformation it's undergoing, and the strategic risks it's facing.

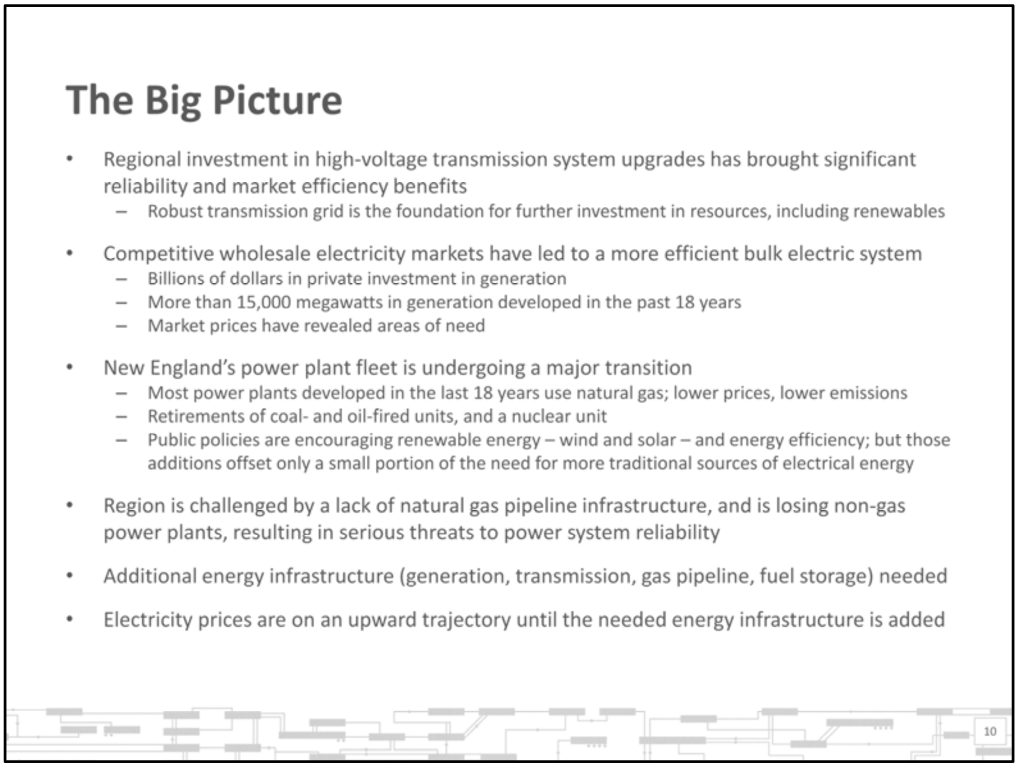


Good morning, I'm Gordon van Welie. Thanks for calling in today. We'll be talking about important issues that affect the wholesale electricity markets and power system operations in New England. It's the ISO's job to make sure the high-voltage power system in New England is reliable now and into the future. Because of our experiences operating the power grid and running the wholesale electricity markets, we have a unique and unbiased perspective on the state of the New England system. The ISO is independent, with no financial stake in the outcome of any market participant's business or projects, and we take no position on any transmission project or power plant proposal. We are also fuel- and technology neutral, ensuring a level playing field for all types of resources in the marketplace.

It's also important to understand that the ISO has no role in the natural gas industry, no financial stake in any natural gas pipeline proposal and, in fact, the ISO has no position on any proposed natural gas pipeline. Finally, the ISO does not make energy or environmental policy, and does not make project siting decisions.

The ISO's most important responsibility is power system reliability—it's what we work on all day, and it is the threats to reliability that keep us up at night. We work intensively with our stakeholders—market participants, state and federal regulators, and consumer advocates—to take the steps needed to ensure the region's 14 million residents can count on the power grid.

I'll focus now on the state of the power grid and the issues we're confronting in New England. The following slides will provide more detail, but I can tell you that the New England power system is in a period of transition that is changing what it looks like, how it operates, and what it costs. We are still able to operate the system reliably, but we've had to take extraordinary steps to do that, especially during winter.



Before we get into the details, I'll set the scene. First, the regional power grid has seen great progress in the nearly 18 years since the ISO was formed as a result of the restructuring of the power industry in New England. We've seen extensive investments to upgrade the high-voltage transmission system and boost reliability.

The competitive wholesale electricity markets have incentivized investment in new, more efficient power plants built by private investors. These markets are providing price signals that indicate where more resources or transmission are needed. Having a robust transmission system and adequate resources to meet demand are the prerequisites to meeting public policy goals, such as expansion of renewables. New England, by and large, has benefited from restructuring of the industry and the introduction of wholesale competition.

The generation investment has resulted in new power plants that are mostly fueled by natural gas. The region has benefited both financially and environmentally from this. Natural gas prices have dropped substantially over the last six years, and these new, more efficient, cleaner-burning generators are running more often and producing about half of the power generated in New England. That's resulted in much lower wholesale power prices, on average, and much lower air emissions.

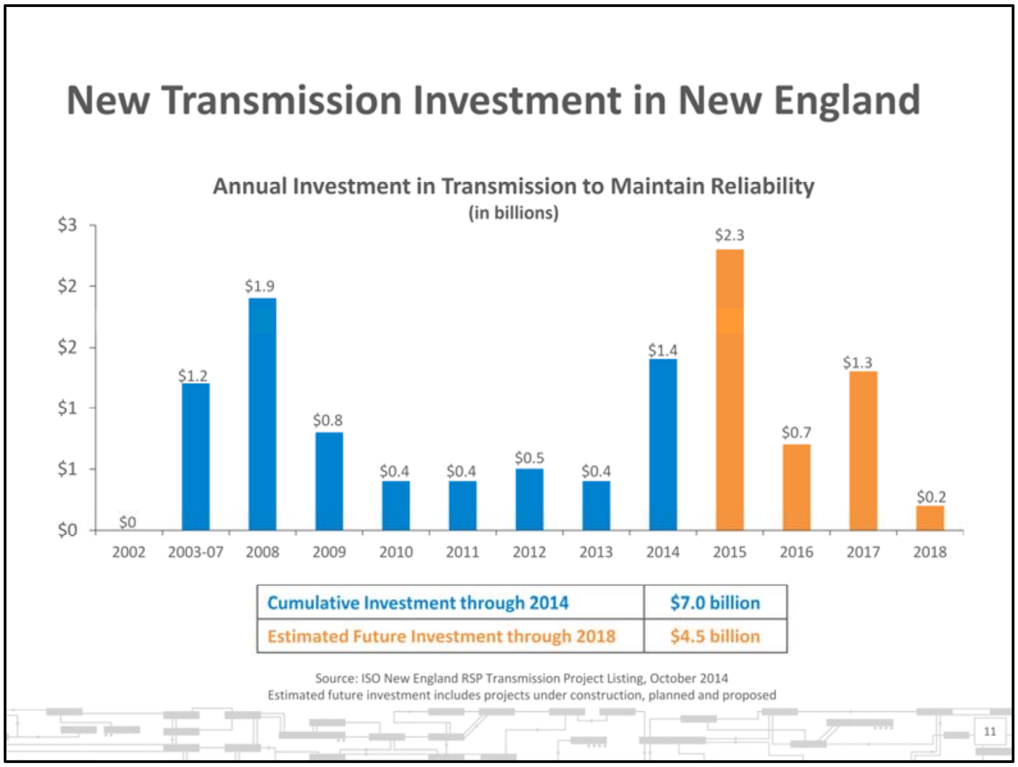
As natural gas prices have dropped, demand for the fuel has risen dramatically in just a few years, faster than the natural gas infrastructure could expand to bring in all the lower-priced gas needed for both heating and power generation. The result is pipeline constraints that mean sometimes these natural-gas-fired power plants can't get fuel.

The low price of natural gas has had another effect. Because natural gas has been cheaper than oil or coal, it's putting financial pressure on oil- and coal-fired power plants. Some are retiring and others are at risk of retiring. Now New England, which has had a surplus of resources in recent years, may not have all the resources we need to meet peak demand for power in the very near future.

And while renewables are a growing portion of the region's resource mix, and will provide a variety of benefits, they are still small in total. Their variable output requires more conventional generation to back them up. They also pose other challenges: the best wind regimes in New England are in remote locations, requiring extensive—and costly—transmission upgrades to unlock their potential; and when demand is peaking in winter, the sun has already set.

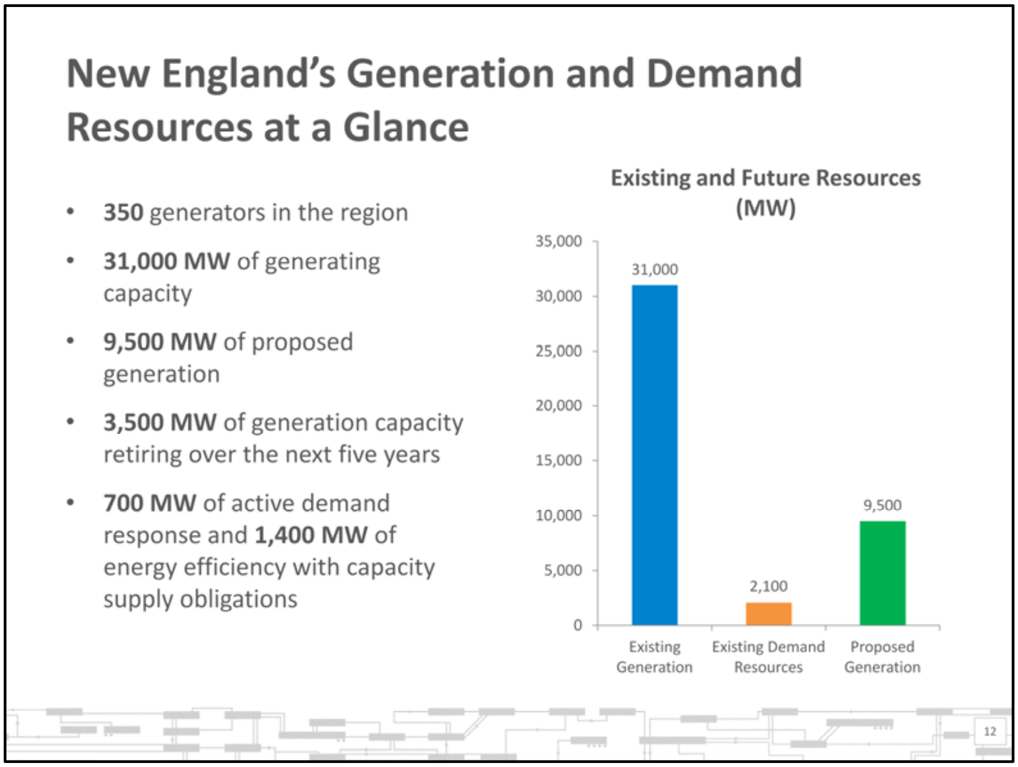
The upshot of all this is an urgent need for more energy infrastructure. It's needed to address the increasing frequency of times that natural gas-fired generators can't get fuel, to make up for retiring generators, and to meet clean energy goals.

As we go through this presentation, I'll tell you what we have seen operating the grid and recap what the ISO has been able to do to address these issues.



The state of the New England power grid has been significantly improved with the region's investment in transmission upgrades—$7 billion since 2002. These upgrades, in all six states, were needed because for several decades before the industry was restructured, investment in the high-voltage transmission system had slowed, so the region has been playing catch-up. The transmission system is vastly improved, but there are still more areas that need work to ensure reliability, at an estimated price tag of $4.5 billion.

The appendix to this presentation includes slides that provide more details about the upgrades completed in each state and areas that are under study, and information about some of the transmission proposals by private investors to bring clean energy to demand centers in southern New England.

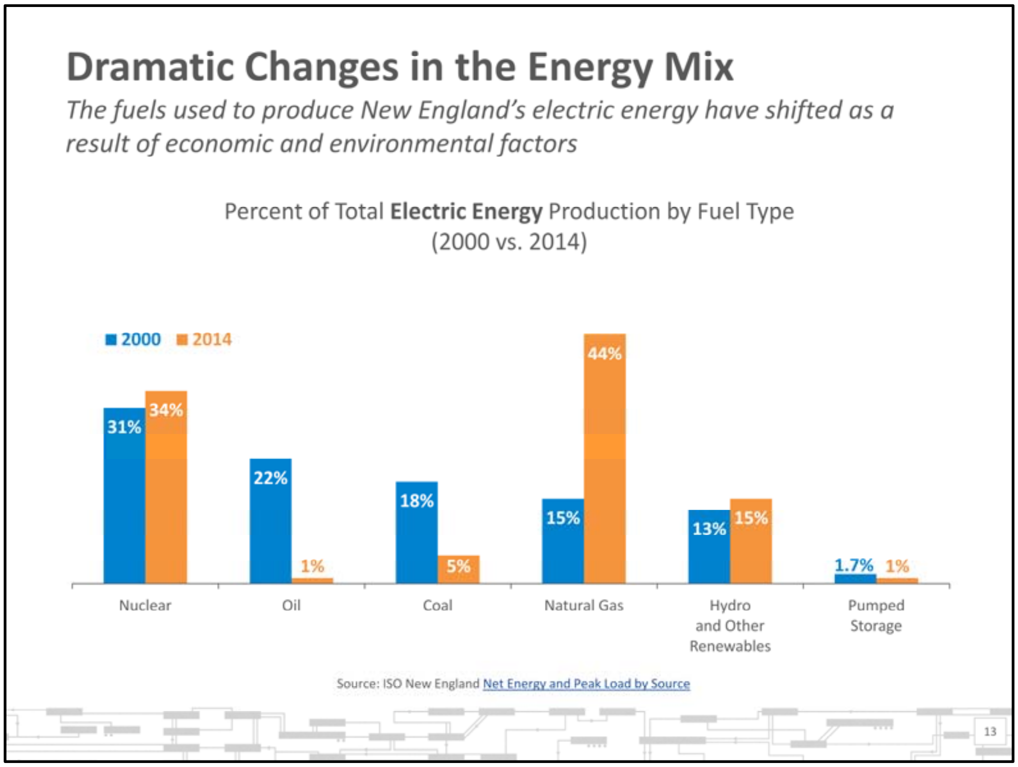


New England has about 350 generators that can be dispatched by the ISO, and hundreds of smaller resources. The generating capacity of all these resources is 31,000 megawatts.

The region also has about 700 megawatts of active demand-response resources—those are, for example, companies that have agreed in advance to turn down lighting or reduce their air conditioning load, when we call upon them to do so. The region also has about 1,400 megawatts of load reduction that comes from energy-efficiency measures.

I'll also talk later about New England's future generation mix, but briefly, there are projects totaling about 9,500 megawatts that have applied to interconnect to the region's power grid. This is an encouraging figure, especially in light of the 3,500 megawatts we'll lose to retirements in the next few years; however, in our experience, many projects never get built—the interconnection queue has historically had an attrition rate of about 70 percent of the megawatts proposed.

On their face, the numbers seem to represent a resource portfolio that is robust enough to meet demand, with proposals to add resources outnumbering proposals to retire power plants. But a look beyond the numbers, at the resource mix, resource performance, and fuel adequacy issues, shows a portfolio of resources that is in transition.

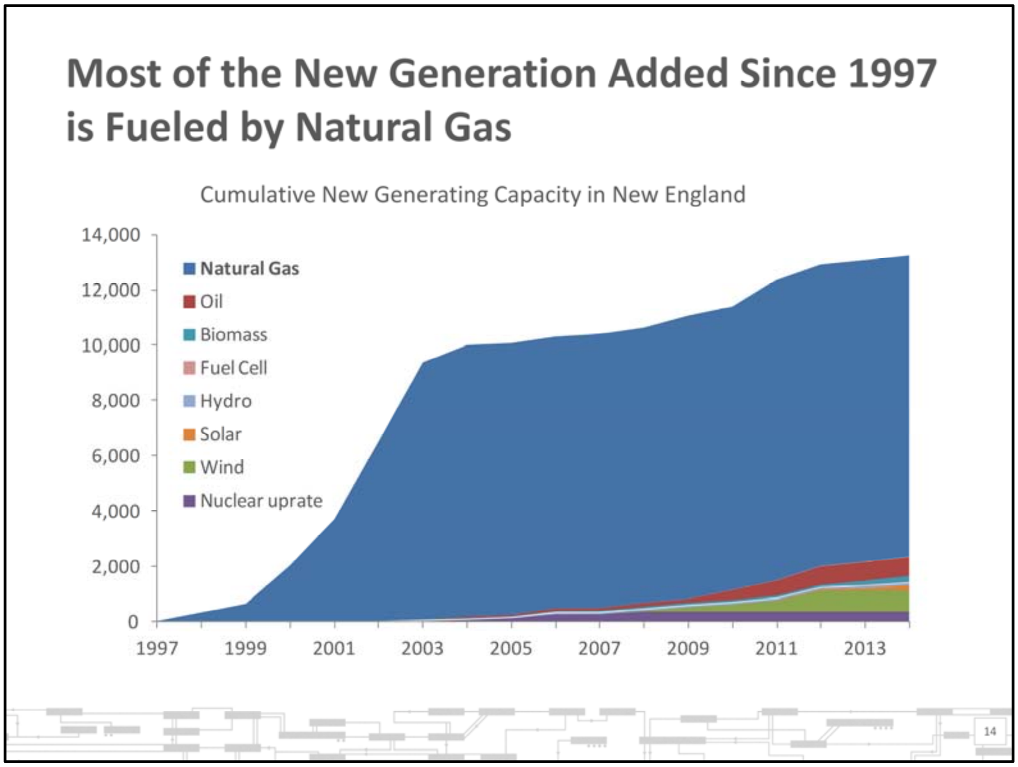


This chart shows that in a very short period of time, the fuels used to generate electricity in New England have shifted dramatically.

The share of electricity produced by natural gas generators increased from 15 percent in 2000 to 44 percent last year.

At the same time, coal- and oil-fired generation, combined, dropped from 40 percent to just 6 percent.

Power plants that aren't called on to run don't get paid in the energy market. Since oil- and coal-fired generators seldom ran in 2014, they seldom received energy payments. However, they are still a significant portion of the region's generation fleet. At 28 percent, their share of total generating capability is almost a third of the total generating capacity of the fleet, even as their share of energy production has declined to 6 percent. Natural gas-fired generators have gone from 18 percent of total fleet capability to 43 percent in just 14 years.



This chart illustrates a couple of points: one, the investment in generation since 1997 in New England has resulted in nearly 15,000 megawatts added to the power system; and two, most of that additional generation is fueled by natural gas—that's the huge blue area.

For several reasons, the growth of natural gas-fired generation in New England occurred organically over the last 15 years, even before domestic shale gas production took off and lowered the price of natural gas. Natural gas generators have relatively low emissions, easing their compliance with environmental requirements; they tend to be less costly to build and easier to site; and the region's transmission improvements have reduced reliance on older units and opened up more opportunities for new generation.

In the meantime, starting in 2008, natural gas production just a few states away, in the Marcellus shale formation, was starting to boom. The supply growth pushed natural gas prices down from record highs in 2008 to record lows in 2012 in New England. These low prices meant natural gas-fired generators were dispatched more often, since the ISO dispatches the lowest-cost generators first to meet demand. The low natural gas prices also encouraged a boom in residential and commercial heating system conversions, from oil to natural gas.

With rising demand for natural gas and very little pipeline expansion, bottlenecks have become more and more frequent, especially in winter. Often, the natural gas pipelines are running full, with no room for additional gas for power generators. If those generators are needed, but they can't get fuel, power system operators need to find alternatives to meet demand for power.

While the ISO's focus is on the reliability impacts of pipeline constraints, they can also cause natural gas and power prices to spike.

While Demand for Natural Gas has Increased, the Pipeline Infrastructure has not Kept Pace

- Why? Unlike electric transmission, new pipelines will not be built without customers signed up for long-term contracts for capacity
- Historically, natural gas generators have not entered into long-term contracts for pipeline capacity
- Several developers have proposed expansion of pipeline and/or storage capacity in region; however, the added capacity is under contract to natural gas local distribution companies (LDCs), not electric generators
- Gas LDCs cannot contract for gas infrastructure expansion beyond the needs of their commercial and residential natural gas customers
- A variety of factors, including economics and legal and regulatory restrictions, hamper private investment in more natural gas infrastructure. The question becomes, how will this infrastructure get built, and who will pay for it?

There's a distinction I want to make clear as we talk about pipeline constraints. There's not a shortage of natural gas supply—there's plenty of natural gas, in nearby states. The high prices come from the bottlenecks on the gas system. The pipelines into New England aren't big enough to carry in all the gas that's in demand, especially in winter, and there's not enough gas storage in the region.

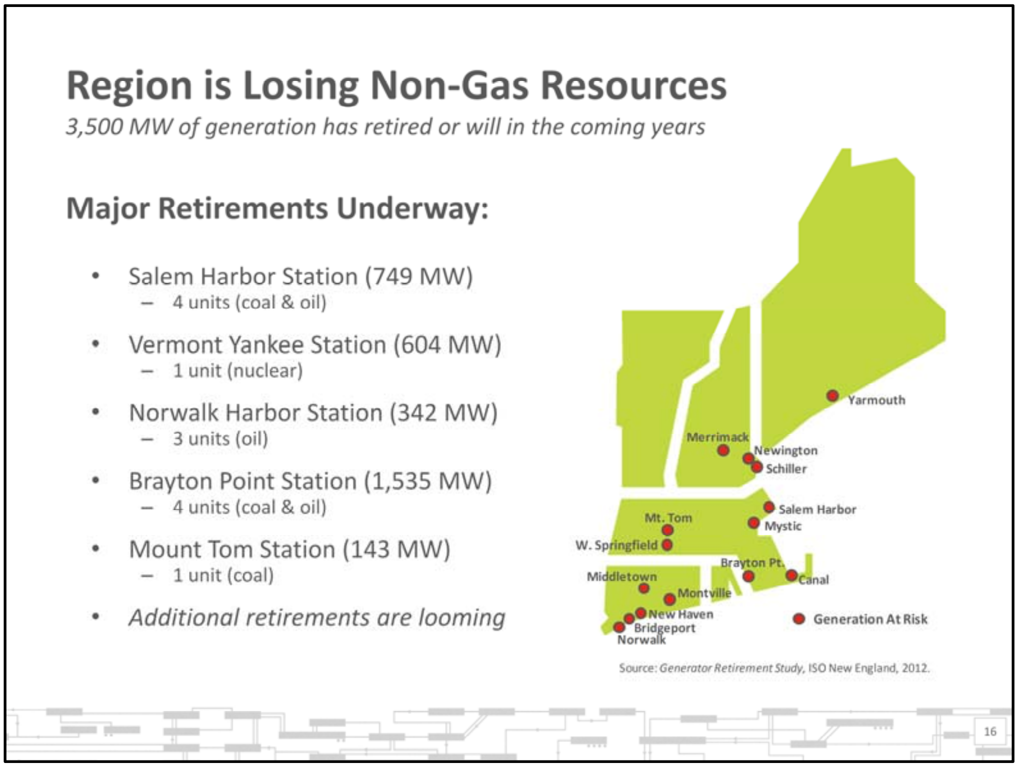
While demand is growing, the pipelines bringing natural gas into New England have not expanded at the same pace. There are several reasons for this lag. There are some fundamental differences between the power and pipeline industries—in the electric industry, transmission line upgrades are designed to meet peak demand 10 years in the future; the pipeline industry is allowed to build new or expanded pipeline only if they have customers signed up for contracts to pay over the long term—15 years, on average.

But most natural-gas-fired generators don't sign long-term contracts with pipelines for natural gas delivery. The wholesale electricity markets have not provided sufficiently strong economic incentives for generators to produce electricity during stressed system conditions, including when the natural gas pipelines are constrained. We have changed those market incentives and implemented interim reliability programs, which I'll expand on later.

Until recently, the fact that power generators didn't have firm contracts for natural gas delivery wasn't much of a problem. Usually, there was room left over on the pipelines after the local gas distribution companies (LDCs) took delivery of the gas they needed to serve their heating customers. The power plants could buy the LDCs' leftover pipeline capacity on the secondary market, and get delivery of the gas they needed, when they needed it.

But more and more people are switching their heating systems from oil to natural gas. Now, especially in winter, when demand for gas is extremely high for heating purposes, the pipelines are running at or near capacity just delivering contracted gas to LDCs. Frequently, there's no room left for gas for generators. That creates reliability risks on the power system.

There are also price risks attached to these pipeline constraints. It is cheaper for gas generators to switch to oil (so called 'dual fuel' capability) than to sign up for more gas pipeline capacity to meet their peak fuel demand in the winter, but both gas and oil are high-priced fuels when the pipelines are constrained. As a result, electricity prices still tend to be high, whether generators are using natural gas or oil.



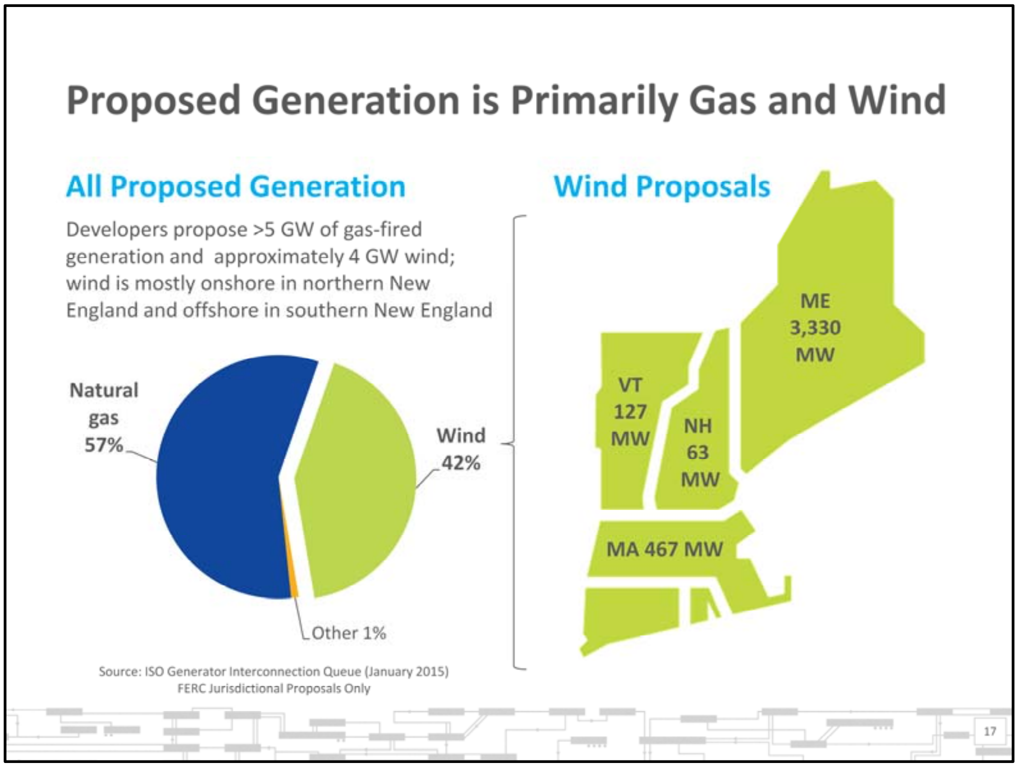
The ISO dispatches the lowest-cost generators first to meet demand. For most of the year, natural gas prices are low, and so natural gas-fired generators have been dispatched more frequently, and at lower wholesale power prices. Power plants fueled by higher-priced oil and coal rarely run, and find it hard to compete and make money.

Four major power plants have already retired or announced they'll retire in the next few years; there are smaller resources retiring as well. These retirements represent more than 10 percent of the region's total generating capacity; they are power plants that use fuel that can be stored on-site, providing a crucial back-up for times when natural-gas-fired power plants can't get fuel; and they are most likely to be replaced by natural gas-fired generators, which will only increase the region's dependence on natural gas.

We're already seeing worrisome conditions in Greater Boston, with the recent retirement of the Salem Harbor station and delays in development of the proposed Footprint natural gas power plant. That area will be short of needed resources as soon as 2016. The Southeastern Massachusetts and Rhode Island zone is also an area of concern, with Brayton Point retiring in 2017. We are studying the power grid in those two areas and assessing steps we can take if new resources don't materialize.

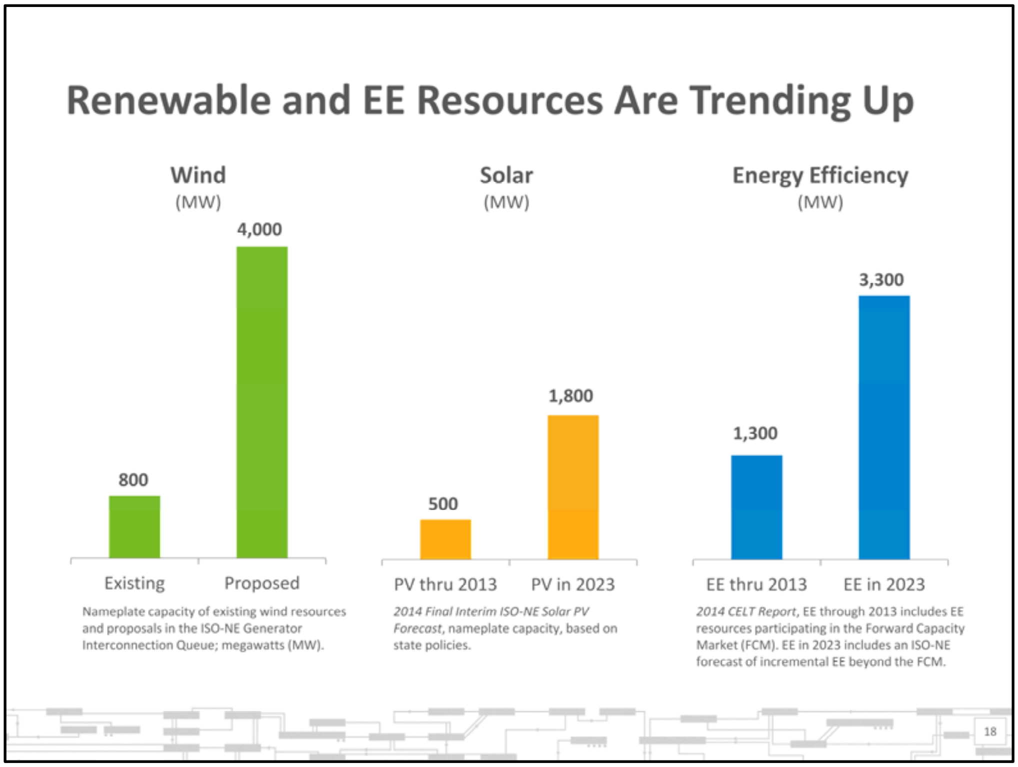
Proposed environmental rules may also accelerate the retirements of aging oil- and coal-fired power plants that could be subject to difficult and costly compliance requirements.

ISO studies have estimated that as much as 8,300 megawatts of older coal- and oil-fired generating capacity could be at risk of retirement, from economic pressures and potentially more stringent environmental requirements. If those 28 generators retire, we estimate 6,300 megawatts of new or expanded capacity would be needed to replace them.



There are 9,500 megawatts of new generation proposed for the region, and that's a good thing, given the generator retirements and concerns about resource adequacy going forward. But remember, as I said earlier, the list of projects has historically seen an attrition rate of about 70% of the megawatts proposed.

Also, as you can see from this pie chart, more than half of the proposed new generation would use natural gas, while almost half would be fueled by wind. This would increase the region's dependence on natural gas for power generation; and while more wind would provide more fuel diversity, most of the wind proposals are in remote areas of northern New England, where the transmission —lines are too skinny to bring all that wind energy down to southern New England. To fully realize the region's wind potential, the transmission system will need to be built out to reach these remote areas, at a cost of billions.



Public policy goals for clean energy will bring new types of resources to the power system; promising a new wave of transformation on the grid.

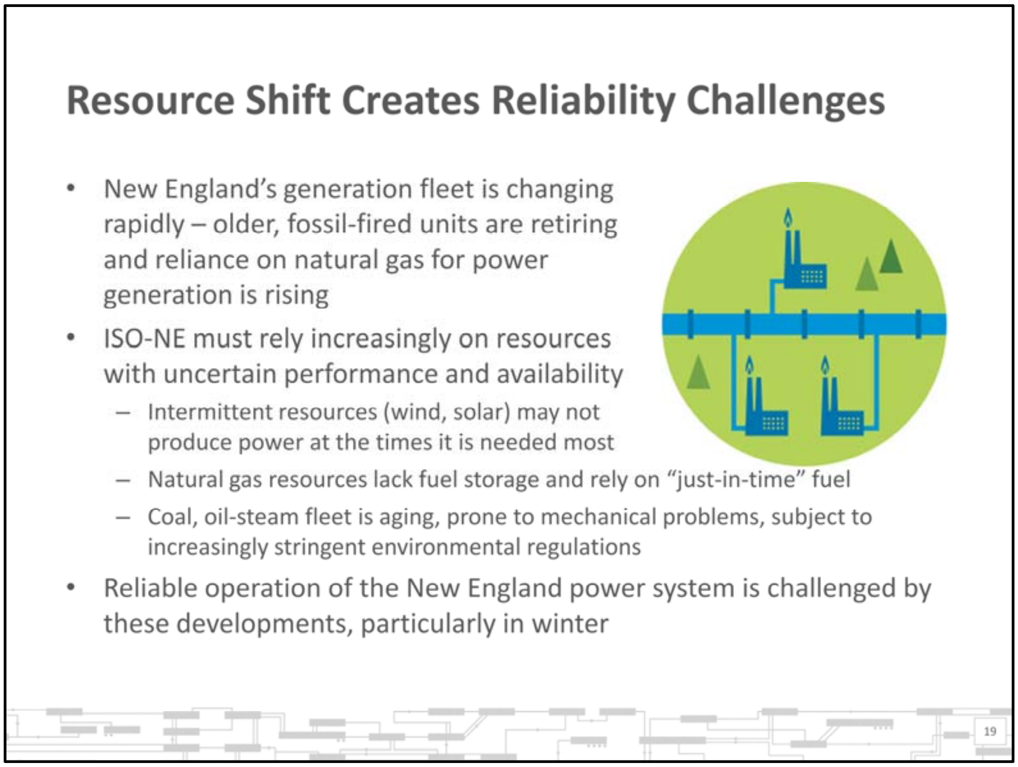
While the levels of wind and solar resources on the New England system are still relatively small, the ISO is preparing for their growth. Our projections show there's no doubt that wind, solar, and energy efficiency will play an increasingly important role going forward.

Regarding solar, these numbers are based on the ISO's interim Distributed Generation Forecast, the first effort in the nation to come up with a multi-state projection of how much distributed generation—mostly solar—will be added. The projection of 1,800 megawatts of solar energy in 2023 is based on state policy goals, representing the maximum possible output of each facility; but given the intermittency of solar energy, we'll need a better technical understanding of how much we're likely to get from these facilities.

Incorporating distributed generation into high-voltage power system operations is complicated—most of it's behind the meter, on the distribution system—so the ISO is preparing for its growth in New England and participating in several national studies to understand the performance of solar under real-world conditions.

The New England states are national leaders on energy efficiency (EE), and EE is an important element of the region's resource mix. Because of the states' commitment to EE, overall annual energy consumption will remain flat in New England over the next 10 years, and peak demand will grow more slowly.

All of these resources, combined, will benefit the regional power grid by diversifying resources, providing clean power, or reducing consumption. However, they will not be enough by themselves, and they will not come online soon enough, to take up the slack that will come with resource retirements that are already underway.



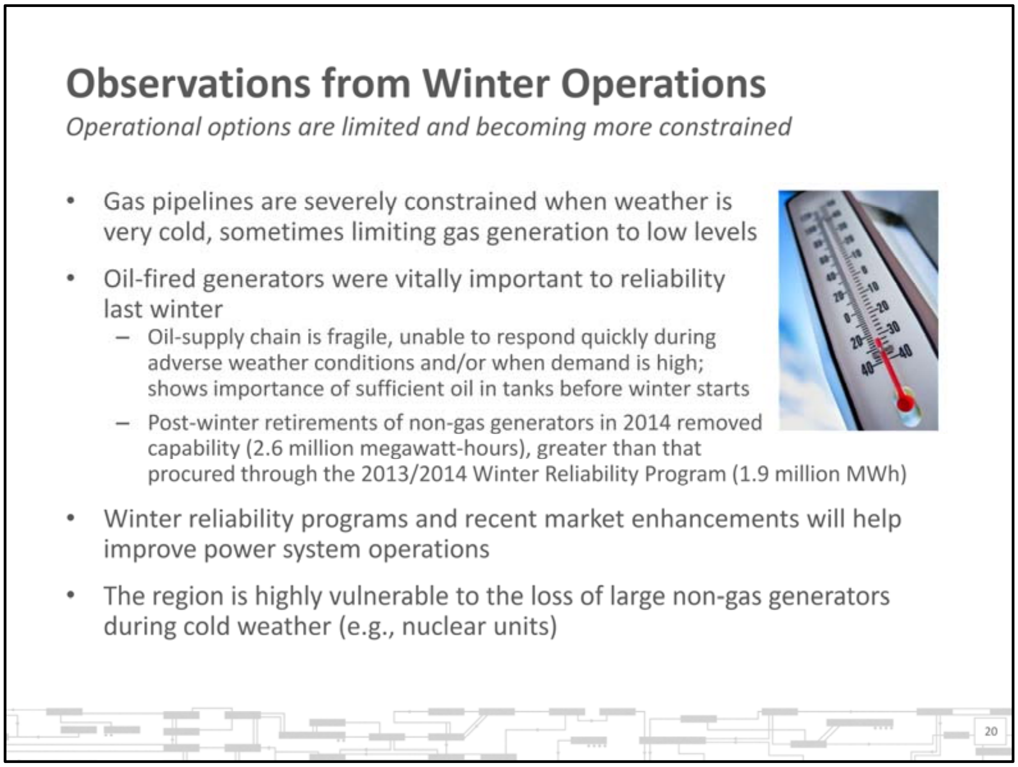
To summarize, the region's power grid has benefited from the billions of dollars invested in transmission upgrades for reliability and in new, more efficient power plants. Expanded natural gas production has lowered prices for most of the year, but has also resulted in increased demand for gas without commensurate expansion of natural gas pipelines.

As we rely more on natural gas for power generation, and extra space on the pipelines disappears in winter, we're frequently finding that natural gas generators can't get fuel when we need them. When that happens, our system operators turn to other types of power plants, such as coal and oil plants that typically store their fuel on-site. But in recent years, aging coal- and oil-fired generators that were seldom dispatched sometimes did not have fuel stockpiles sufficient for extended operation when needed; and they often experience mechanical problems when they try to start up after long dormant periods.

And now we're starting to see coal- and oil-fired power plants retire, removing them entirely from the suite of options for system operators.

Wind and solar resources are a small but growing part of the region's portfolio, but they are not always available when needed; for example, peak demand for power in winter typically occurs after the sun has set.

All these developments are converging to create serious reliability challenges, especially in winter.



The last two winters, of 2012/2013 and 2013/2014, have provided examples of the increasing challenges to maintaining system reliability.

For example, two years ago, during Winter Storm Nemo in February 2013, our system operators were calling pipeline operators at 1 a.m. in the morning, trying to ensure that a natural gas-fired generator that we badly needed would be able to get fuel. Reliability was maintained, but it was a close call.

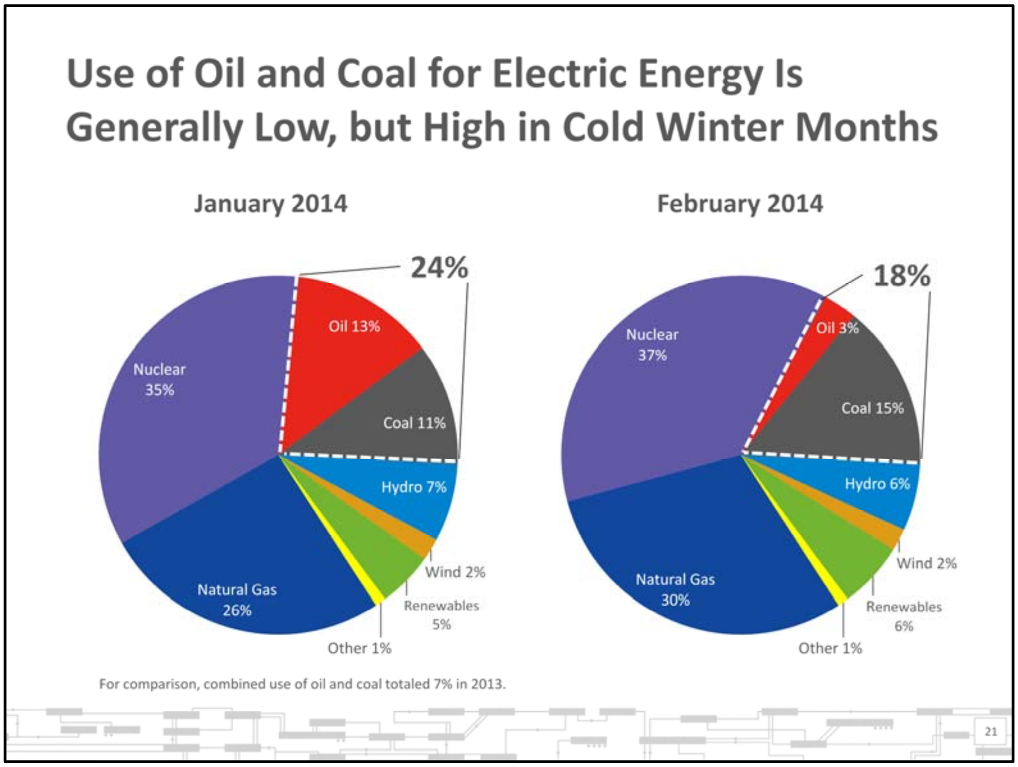
Then last winter, in early 2014, natural gas pipeline constraints pushed natural gas prices to record highs. As a result, oil-fired power plants were often more economical to run. Fortunately the oil-fired generators had enough fuel in their tanks to enable them to run during last winter's bitter cold weather, but it wasn't luck. After our experiences with fuel adequacy —including oil-fired generators running out of fuel during winter 2012/2013—we implemented a Winter Reliability Program for winter 2013/2014. That supplemental program provided financial incentives for oil-fired generators to store more oil than they otherwise would have, and it was critical in maintaining reliability last winter.

Last winter showed us that the natural gas pipelines were even more constrained than we had previously thought. That's significant, because frequently, there were relatively few natural gas-fired-generators online and using gas. The pipelines were mostly full with gas going to heating customers.

Generators using fuels other than natural gas are especially important to maintain reliability in winter, but many of those units are retiring. Last winter, Vermont Yankee and Salem Harbor were online and available. With their retirements, their combined capacity of 1,200 megawatts of non-natural-gas-fired generation is no longer available to system operators.

The Winter Reliability Program is a form of insurance for fuel adequacy, and we've taken other steps to help improve resource performance during times of system stress, but if a major generator that doesn't use natural gas trips offline at a time when natural gas generators can't get gas, our options are increasingly limited.

So far, this winter has been relatively mild compared to the past two. Mild December weather lowered demand for power, and for natural gas, and pipeline constraints were less prevalent. Wholesale prices also dropped. But this is New England. Winter's not over yet, and a mild winter or two doesn't guarantee we won't have extremely cold winters again.



These pie charts show how much we've had to rely on coal- and oil-fired power plants in winter. They contributed 6 percent of all the energy produced in New England last year, but when demand is peaking—and when natural gas-fired generators can't get fuel—they are crucial for reliability. During last winter's extreme cold weather, they contributed 24% of the energy in January and 18% in February.

While they were critically important to maintaining reliability, there's a downside: greater use of oil- and coal-fired power plants contributes to higher air emissions.

So far this winter, coal and oil use has been low compared to last winter, but the mild weather is driving lower natural gas prices, so natural gas generators are likely to be dispatched first to meet demand, before oil and coal plants.

ISO Developed a New Reliability Program for Winter 2014/2015

- **Key Drivers**:
  - Generators' difficulty in replenishing oil supplies mid-winter
  - Gas pipelines have been more constrained than anticipated
  - Retirement of a significant amount of non-gas generation
- **Objective**: Augment scarce pipeline gas and improve the region's overall fuel adequacy
- **Solution**:
  - Create an incentive for generators to secure fuel supply and delivery arrangements going into the winter
  - Offset costs for generators to commission dual-fuel capability
  - Offset part of the carrying costs of firm fuel purchased by generators (fuel oil and LNG) that is unused at the end of the winter season
  - Compensation for new demand-response services

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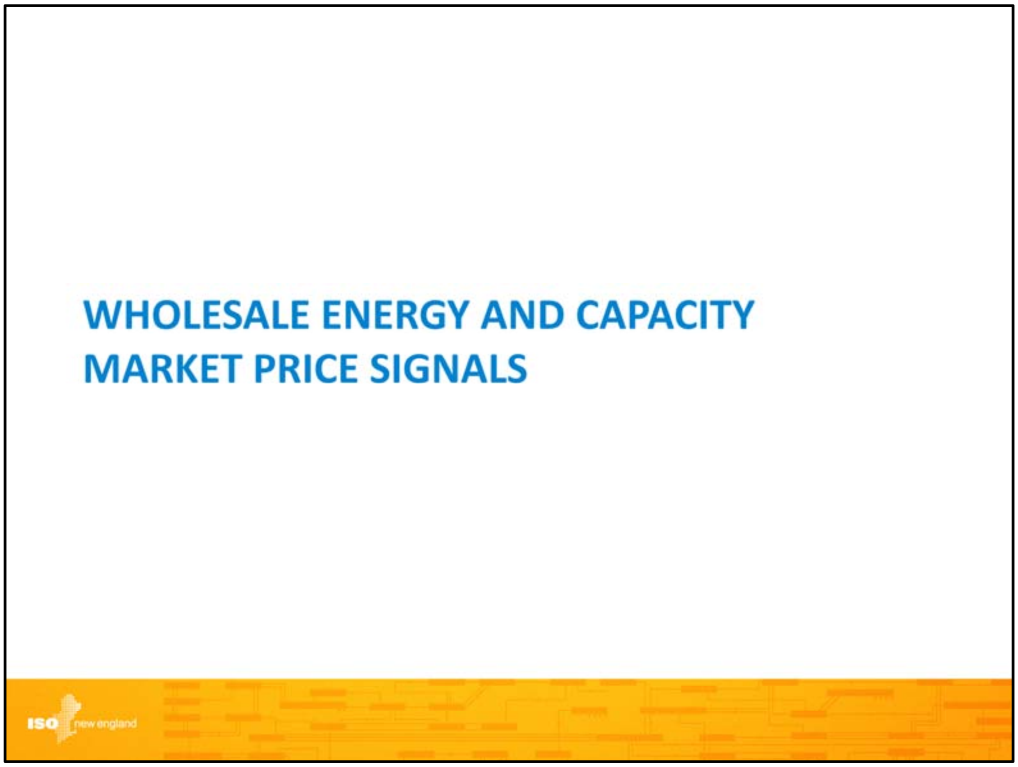
Our system operators faced extreme challenges during winter 2012/2013. Based on that experience, we developed a reliability program to ensure fuel adequacy through winter 2013/2014. That program turned out to be critical to maintaining reliability last winter. Even with that program, last winter exposed new and continuing challenges. For instance, oil-fired power plants started the winter with adequate fuel in storage, but used it up quickly during January's extreme cold and had difficulties replacing it. The knowledge that two large non-natural gas-fired generators would retire before this winter also heightened concern, so we developed a second Winter Reliability Program to ensure fuel adequacy for the current winter.

This year's program has drawn robust participation from oil-fired and dual-fuel generators that stocked oil and contracted for LNG. We also got some new demand-response resources. Most significantly for long-term fuel security, six units representing about 1,700 megawatts have decided to take advantage of new incentives for generators to add dual-fuel capability. With that capability, if a dual-fuel generator can't get gas or the price of gas is higher than oil, it can instead use oil stored in a tank on-site.

However, using oil instead of natural gas increases emissions of pollutants into the air, which is counter to the states' environmental goals. Resource owners seeking to add the ability to burn oil as a secondary fuel may run into permitting obstacles or restrictions on how often they can run. While some of these new dual-fuel capabilities have been permitted, we're not sure how much more will be allowed.



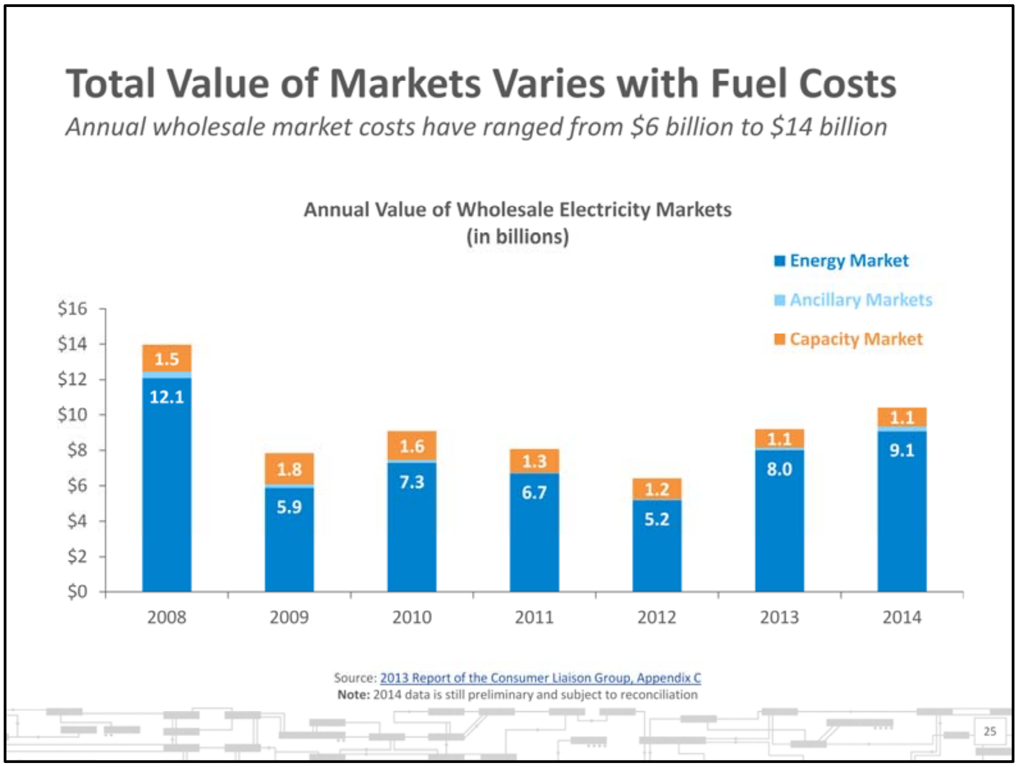
I want to talk briefly about the competitive markets, because the price signals emerging from these markets inform investors' decisions to build power plants or add DR resources, or retire resources, or make other types of investments in their facilities to ensure they can operate when needed.

New England's Wholesale Markets at a Glance

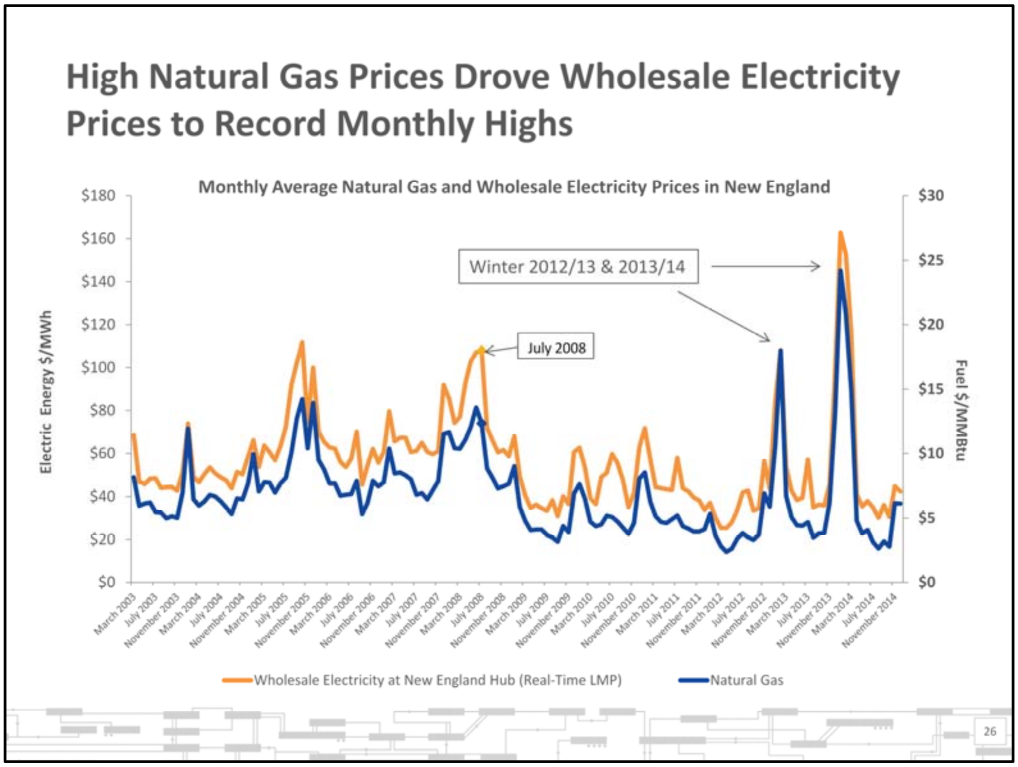
- More than **400** buyers and sellers in the markets
- **$10.4 billion** traded in wholesale electricity markets in 2014*
  - **$9.1 billion** in energy markets
  - **$1.3 billion** in capacity and ancillary services markets
- Forward and spot markets
- Prices vary by time and location, and by changes in demand and available resources

* **Note:** 2014 wholesale electricity market data is still preliminary and subject to reconciliation

First, an overview of the markets: New England's energy, capacity and ancillary services markets trade billions of dollars every year. Preliminary data indicates the New England markets traded a total of $10.4 billion in 2014. That's more than $1 billion higher than the 2013 value. While the energy market value hit record-high power prices in the first two months of last year, the remainder of 2014 saw milder weather and lower natural gas prices, which has moderated the total value.



You can see that the highest energy market value occurred in 2008, at $12.1 billion, when natural gas prices were high, while the lowest market value was $5.2 billion in 2012, when gas prices were at record lows. The energy market total varies from year to year as a direct result of changing fuel costs. The largest portion of wholesale energy costs is fuel; since natural gas is the predominant fuel used in New England to generate electricity, wholesale energy prices follow the price of natural gas. This linkage is illustrated on the next slide.

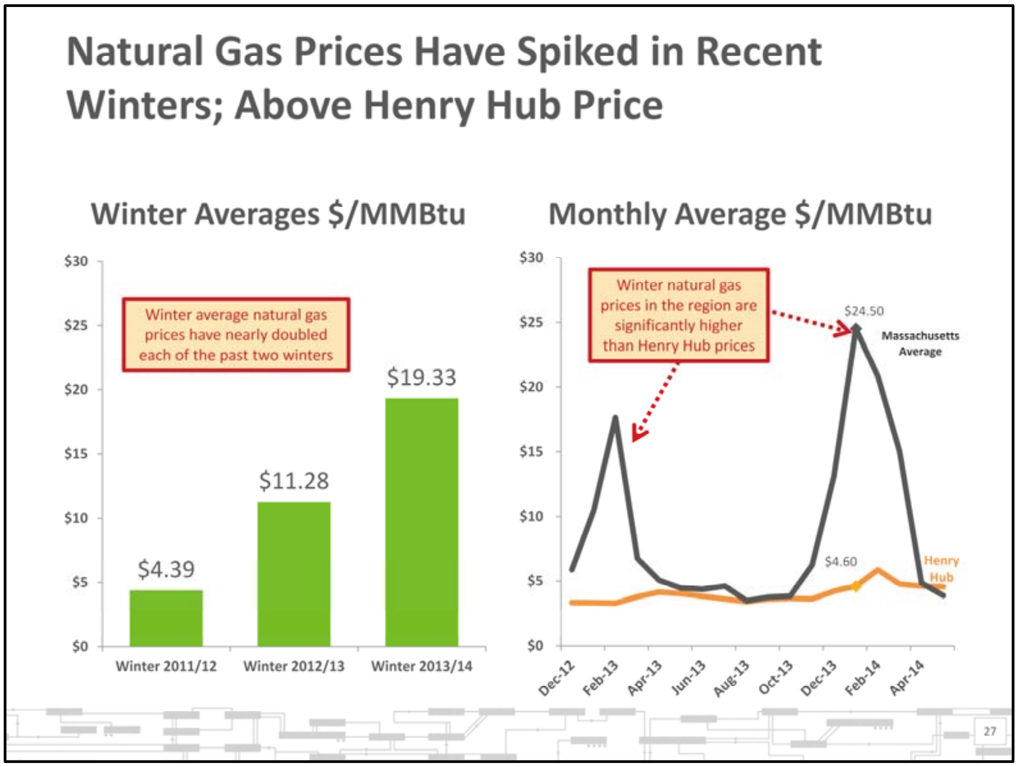


This chart shows the average monthly price for natural gas and wholesale electricity, and how wholesale power prices track natural gas prices. Clearly, when natural gas prices drop, wholesale power prices follow suit; when natural gas prices rise, power prices rise also.

As average monthly natural gas prices started dipping in mid-2008, monthly wholesale power prices also dipped. The natural gas price spikes of the last two winters are echoed in wholesale power prices. As painful as higher prices can be, they show that markets are working—just as the lower prices of 2009 through 2012 were an indication of markets working.

Efficient and competitive markets react to an imbalance between supply and demand. When shale gas is abundant and available in New England, the low market price reflects that the supply is available to meet demand. Now, the record-high prices of the last two winters are revealing the pipeline constraints that are limiting the supply of natural gas for both heating and power generation in New England.

Low natural gas prices so far this winter have helped keep wholesale power prices low. But as this chart demonstrates, natural gas prices can be volatile, especially in New England.

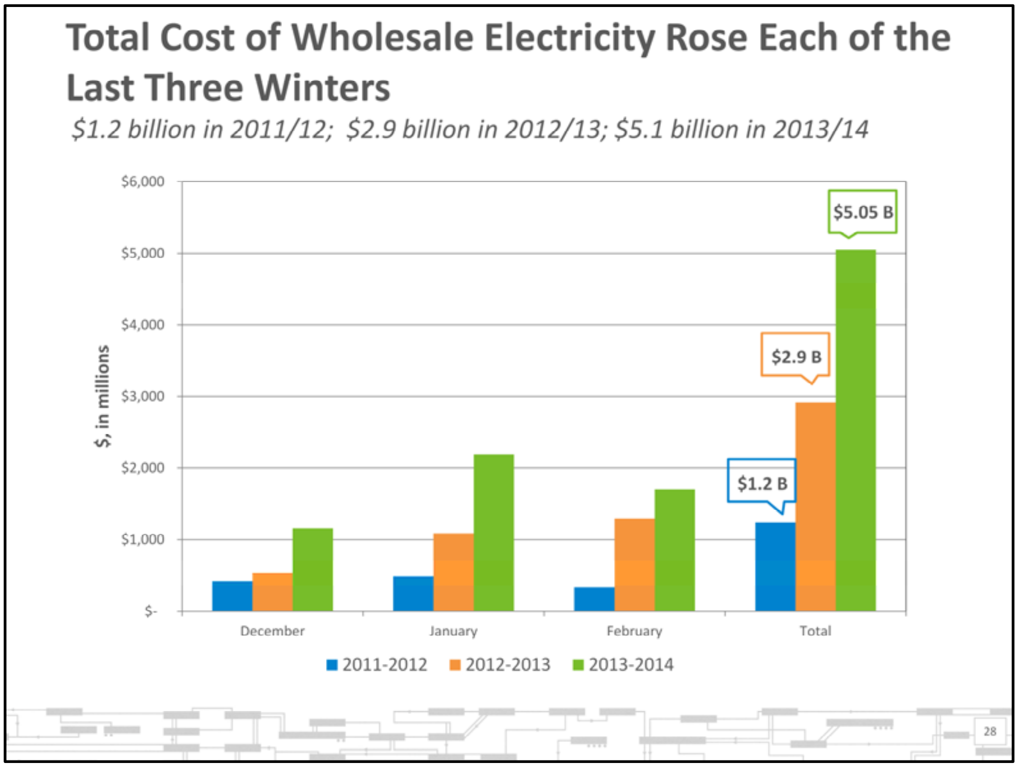


For each of the last three winters, natural gas prices have risen steeply, showing the effects of increasing pipeline constraints.

The graphic on the right illustrates the steep price premium for natural gas in New England, compared to the Henry Hub price, a standard pricing point for natural gas trades in the US.

On January first, 2014, the spot price for natural gas in New England was nearly $20 higher than the price paid in most of the country.

The US Energy Information Administration attributes the higher New England prices to natural gas pipeline constraints. If you want to take a look at some of these reports, a slide in the Appendix provides links.



The supply-and-demand imbalance caused by pipeline constraints in New England has had a dramatic impact. The premium paid by the region has translated into record-high power prices and soaring energy market costs. The total value of the energy market for the three months of winter 2013/2014 was nearly $5.1 billion; that compares to $5.2 billion for all 12 months of 2012, when New England consumers benefited from record-low natural gas prices.

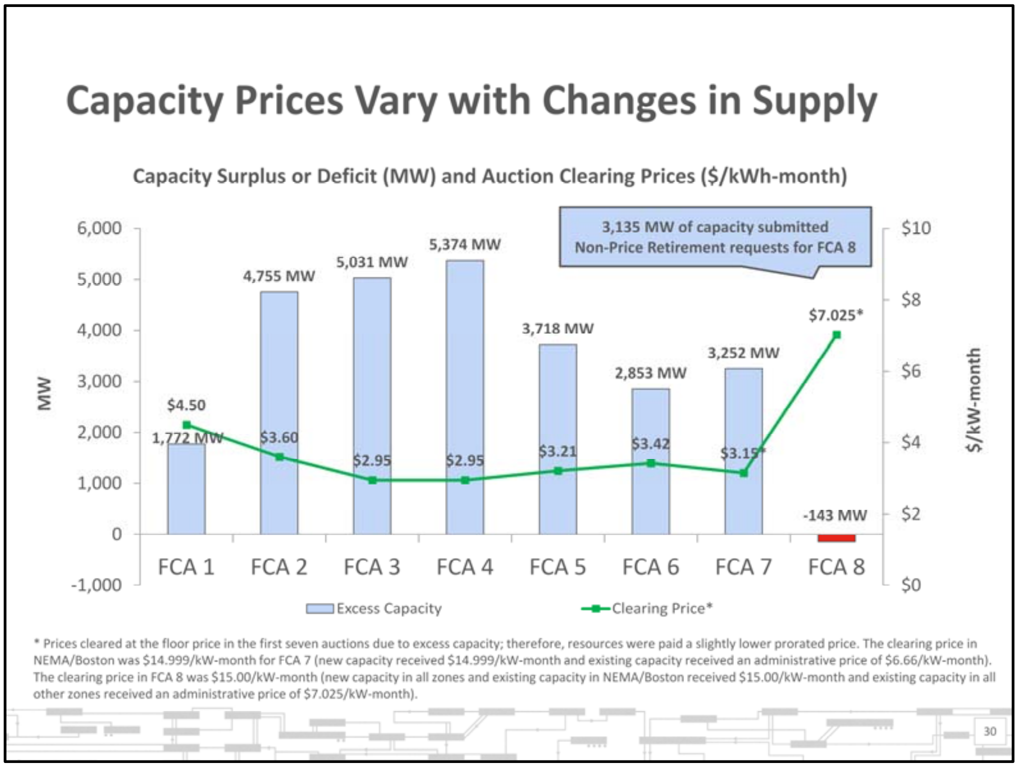
As demand for gas rises and pipeline constraints grow tighter, the total winter bill for natural gas and power in New England seems likely to go higher. When we post this presentation to our website later today, you can find a slide in the appendix that shows the forward natural gas and power prices that FERC found back in October for New England. They were not only the highest forward prices in the US, at the time they were the highest on the planet.

These high forward prices, coupled with the economic incentives in our Winter Reliability Program, ensured that generators had a robust oil and LNG inventory this winter. Since then, the combination of fewer pipeline constraints and high levels of fuel supply and relatively mild weather, which dampened demand for natural gas for heating, have lowered the price for natural gas and, by extension, the price for wholesale power.

The supply and demand imbalance is evident in the region's Forward Capacity Market as well. That market is separate from the energy market, where electricity is bought and sold. The capacity market provides a forward payment to generators to produce electricity in three years' time. They only get this money if they actually produce electricity when needed. Before restructuring, utilities recouped the capital costs of the resources they built through cost-of-service rates, irrespective of whether the unit was able to run on the day it was called.

With restructuring, utilities in most New England states were required to sell their generation assets to private investors. The capacity market is designed to provide a contribution toward fixed costs that previously were recovered through rates when the power plants were owned by the state-regulated utilities. The capacity market ensures the region has sufficient resources to meet peak demand, with an annual auction to procure the level of resources we project will be needed in three years' time.

Until the generator retirements announced in late 2013, the region had been enjoying a capacity surplus and low capacity prices.

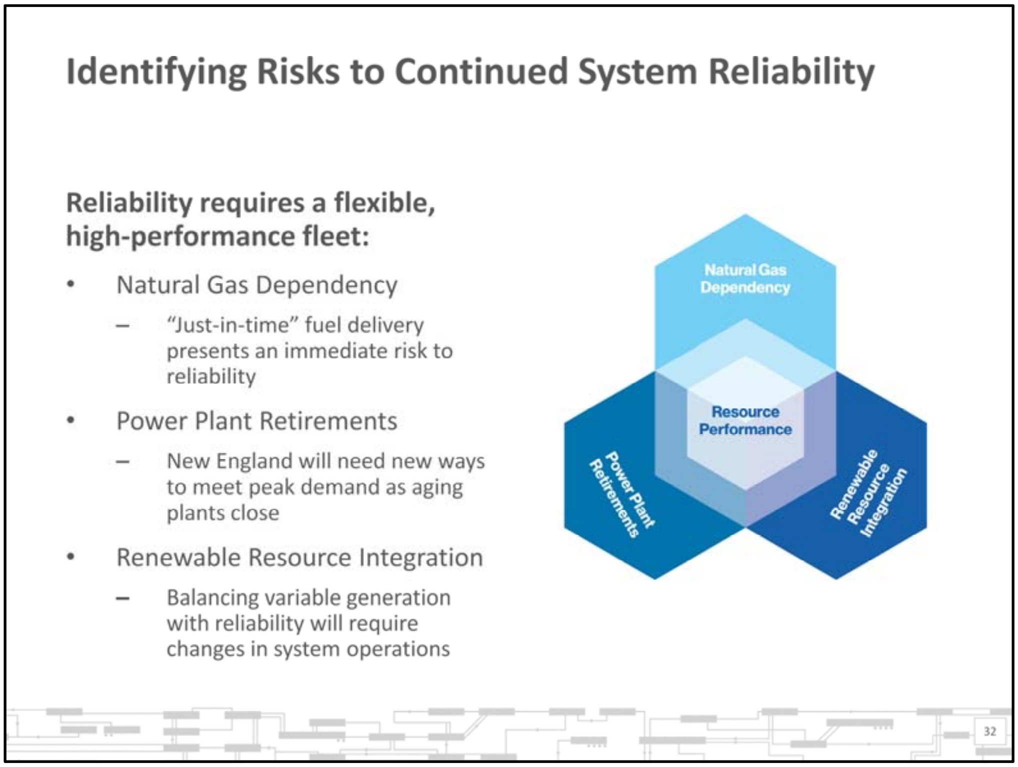


This chart shows the surplus capacity coming out of each capacity auction, until the shortfall in the Forward Capacity Market Auction #8, and the associated auction clearing price.

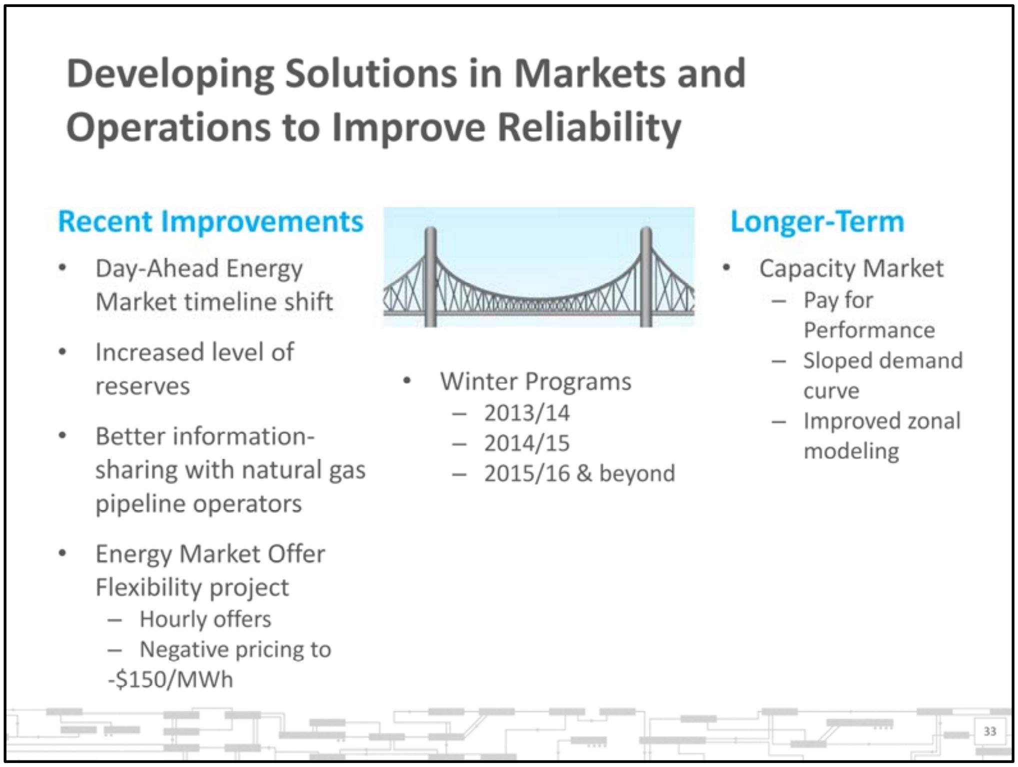
When the region had surplus capacity, capacity prices were generally low. For some generators, these prices were insufficient to cover their operating costs and capital investments. In many cases, environmental regulations were also requiring plant owners to make additional capital investments. Those are the primary forces behind the growing number of resource retirements.

The resource retirements have erased the surplus and led to the slight shortfall in capacity in the last Forward Capacity Market auction. The supply-and-demand dynamic kicks in again: A shortage of capacity results in higher capacity prices. The higher prices are sending a signal to the market that more resources are needed; in fact, that signal may be working—the applications to build generation jumped from about 6,100 megawatts last March to 9,500 megawatts in January.

IDENTIFYING RISKS, DEVELOPING SOLUTIONS



Several years ago, ISO New England identified the key challenges to maintaining power system reliability, with natural gas dependency the foremost risk to power system operations and resource retirements a close second.
The states' goals for clean energy are supporting the growing importance of renewable resources in the region's energy mix, and we've been preparing for integration of renewables for several years.



We identified these major risks, then rolled up our sleeves and worked with our stakeholders to evaluate an array of possible solutions that could be implemented in those areas where we have jurisdiction—that is, power system operations and wholesale electricity markets.

We looked for solutions that would address the root causes of the resource performance issues we were seeing. Our goal was to make changes that would keep markets competitive and the playing field level for all types of resources, while making sure generators could recoup the costs of investments needed to ensure they could perform when needed.

This slide contains a very short list of the many changes we've made.

Our coordination with the natural gas pipeline industry, formally initiated in 2004, has only gotten better.

We've increased the level of reserves we carry each day to be able to recover from unexpected outages or a shortfall of resources that can't make it online.

We shifted the deadlines for resource offers in the day-ahead market to more closely align with the natural gas trading schedule, so generators would have an easier time of securing gas for the following day.

We just completed a massive project to revise almost every software program at the ISO, allowing generators to revise their offers to provide power as frequently as every hour, as their fuel costs change. At the same time, we changed the minimum offer price to minus $150 per megawatt-hour.

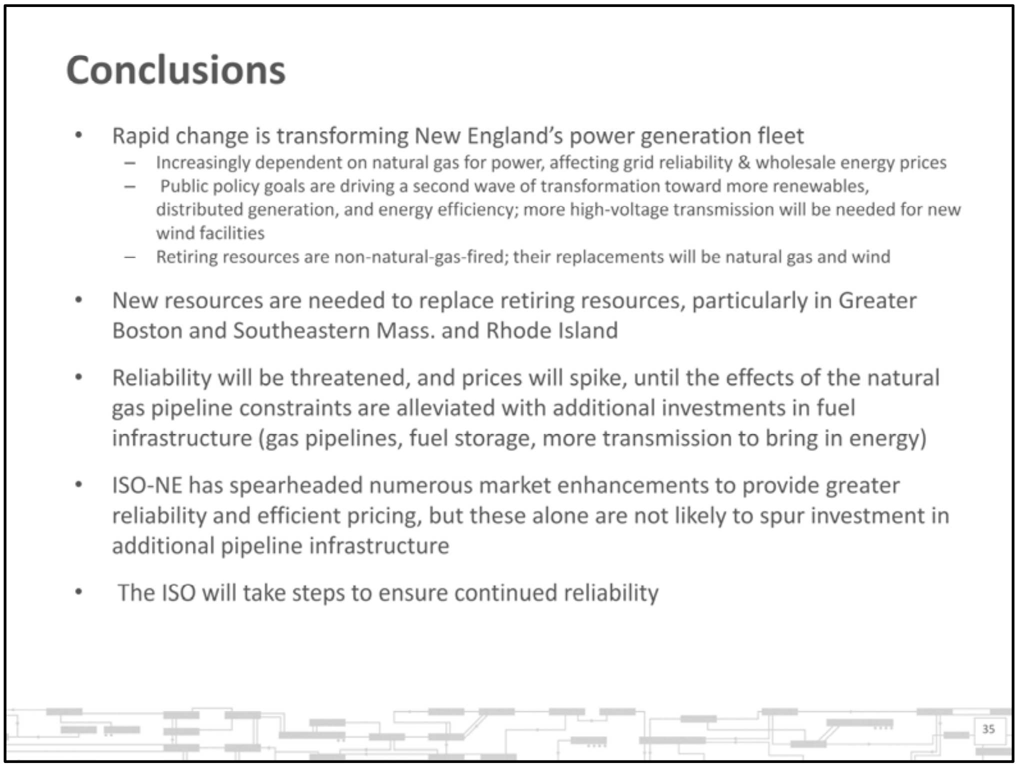
Pay for Performance, a fundamental reform to the capacity market, will significantly boost incentives for resources to make the investments needed to ensure they can perform when we need them. Resources that overperform during times of system stress will receive more money, to be paid out by resources that underperform. That will go into effect in 2018-2019, for resources that clear in the upcoming capacity market auction.

There are several slides in the appendix that explain some of these projects more fully.

The ISO has extensively studied the region's natural gas dependency for power generation, assessed the growing demand for natural gas, and concluded that more energy infrastructure is needed—more pipeline, or more storage for liquefied natural gas and oil, or more alternative sources of energy—or, more likely, all of the above.

These study results are not unique—every study to date, including the recently issued Massachusetts study, has concluded that more energy infrastructure is needed.

Now the question is, where will the investment come from to address the need for additional energy infrastructure? As the previous slide illustrates, the ISO and power industry stakeholders have made extensive changes to the wholesale electricity markets and operations to address these ongoing reliability risks, but these changes alone may not be enough.



The region has made many of the transmission upgrades needed to bolster New England's high-voltage power system, though more is needed; and the competitive markets have successfully helped signal the need for new resources.

But the region's growing dependence on natural gas for power generation, combined with increased demand for natural gas for heating, has resulted in pipeline constraints and reliability risks that are only expected to grow.

The market forces that have brought increased natural gas-fired generation are squeezing other types of power plants out of the market, and these retirements are creating resource adequacy concerns and worsening the risks due to inadequate fuel arrangements.

Renewables, distributed generation such as solar, and energy-efficiency measures are a growing part of the resource mix, but they are not being added fast enough and at a scale large enough to fill the growing gaps.

To ensure power system reliability, additional energy infrastructure is needed. That could include more natural gas pipelines, more transmission lines to bring in energy, or more storage for LNG and oil—but it's likely to require a combination of all of the above.

The region faces a conundrum: who will be the customer to ensure new gas infrastructure is built? Will it be end-use electricity consumers or electricity producers (that is, generators)? Thus far, electric generators have not signed up for additional gas infrastructure and as a result, the New England states have been considering making an investment in additional gas infrastructure on behalf of consumers.

Until more infrastructure is added, consumers can expect volatile pricing for both natural gas and wholesale power, with price spikes when either the pipeline or power system is operating under stressed conditions.

Addressing the region's fuel adequacy and resource adequacy issues will not be easy or inexpensive. Until they are resolved, the ISO will take the steps needed to keep the lights on.

Questions

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APPENDIX

Appendix Contents

- For More Information….
- Links to EIA Reports Regarding New England Prices & Pipeline Constraints
- New England's Energy Use at a Glance
- New England's Electricity Use Varies by Season
- Transmission Projects to Maintain Reliability Have Progressed in Each State
- ISO Continuously Studies Transmission System Needs to Maintain Reliability
- On- and Off-shore Merchant Transmission Proposals Vie to Move Renewable Energy to New England Load Centers
- Greater Boston Area Needs Resources and Transmission
- Southeastern Mass and Rhode Island Areas Need Resources and Transmission
- FERC's Winter Market Assessment Found NE had Highest Winter Power and Natural Gas Futures
- Energy Market Offer Flexibility Enhancements
- Reserve Constraint Penalty Factor Changes
- Problems with Existing Capacity Market Design
- Pay for Performance

For More Information…

- Subscribe to the ***ISO Newswire***
  - *ISO Newswire* is your source for regular news about ISO New England and the wholesale electricity industry within the six-state region
- Log on to **ISO Express**
  - ISO Express provides real-time data on New England's wholesale electricity markets and power system operations
- Follow the ISO on **Twitter**
  - @isonewengland
- Download the **ISO to Go App**
  - ISO to Go is a free mobile application that puts real-time wholesale electricity pricing and power grid information in the palm of your hand

GET IT ON Google play

Download on the App Store

Links to EIA* Reports Regarding New England Prices & Pipeline Constraints

- 1/20/2015 – EIA, NERC assessment examines winter power system reliability, fuel diversity http://www.eia.gov/todayinenergy/detail.cfm?id=19631#
- 1/12/2015 – EIA, Wholesale power prices increase across the country in 2014 http://www.eia.gov/todayinenergy/detail.cfm?id=19531#tabs_SpotPriceSlider-2
- 11/24/2014 – EIA, Boston, New York City winter natural gas prices expected to remain high; http://www.eia.gov/todayinenergy/detail.cfm?id=18931
- 8/11/2014 – EIA, Northeast natural gas spot prices particularly sensitive to temperature swings; http://www.eia.gov/todayinenergy/detail.cfm?id=17491
- 2/21/2014 – EIA, New England spot natural gas prices hit record levels this winter; http://www.eia.gov/todayinenergy/detail.cfm?id=15111
- 1/21/2014 – EIA, Northeast and Mid-Atlantic power prices react to winter freeze and natural gas constraints; http://www.eia.gov/todayinenergy/detail.cfm?id=14671
- 1/9/2014 – EIA, Energy Market Alert: Northeastern Winter Natural Gas and Electricity Issues http://www.eia.gov/special/alert/east_coast/

US Energy Information Administration: www.eia.gov

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Links to EIA Reports, continued

- 1/7/2014 – EIA, Energy Market Alert: Northeastern Winter Natural Gas and Electricity Issues; http://www.eia.gov/special/alert/east_coast/pdf/energy_market_alert_Jan_7_2014.pdf
- 12/6/2013 – EIA, December natural gas prices spike in Boston http://www.eia.gov/todayinenergy/detail.cfm?id=14071
- 4/12/2013 – EIA, Winter natural gas price spikes in New England spur generation from other fuels http://www.eia.gov/todayinenergy/detail.cfm?id=10791
- 3/25/2013 – EIA, Over half of US natural gas pipeline projects in 2012 were in the Northeast (New England remains isolated); http://www.eia.gov/todayinenergy/detail.cfm?id=10511
- 1/18/2013 – EIA, Constraints in New England likely to affect regional energy prices this winter http://www.eia.gov/forecasts/steo/special/pdf/2013_sp_01.pdf
- 1/23/2012 – EIA, Spot natural gas prices at Marcellus trading point reflect pipeline constraints http://www.eia.gov/todayinenergy/detail.cfm?id=7210
- 9/29/2011 – EIA, Markets indicate possible natural gas pipeline constraints in the Northeast this winter http://www.eia.gov/todayinenergy/detail.cfm?id=3290
- 2/17/2011 – EIA, Pipeline constraints raise average spot natural gas prices in the Northeast this winter http://www.eia.gov/todayinenergy/detail.cfm?id=170

New England's Energy Use at a Glance

- **6.5 million** households and businesses; **14 million** population
- **28,130 MW** all-time summer peak demand set on August 2, 2006
- **22,818 MW** all-time winter peak demand set on January 15, 2004
- Region's *peak* demand forecasted to grow **1.3%** annually
- Region's *overall* electricity demand forecasted to grow **1.0%** annually
- Energy efficiency slows growth in peak demand and flattens overall electricity demand

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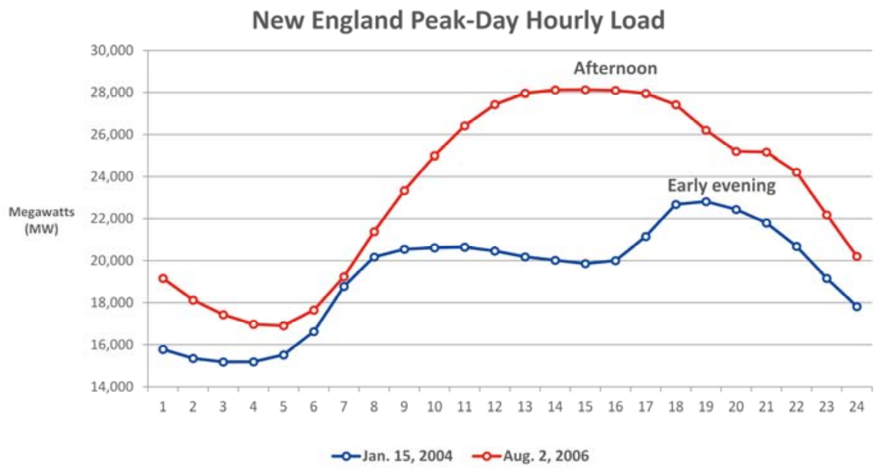
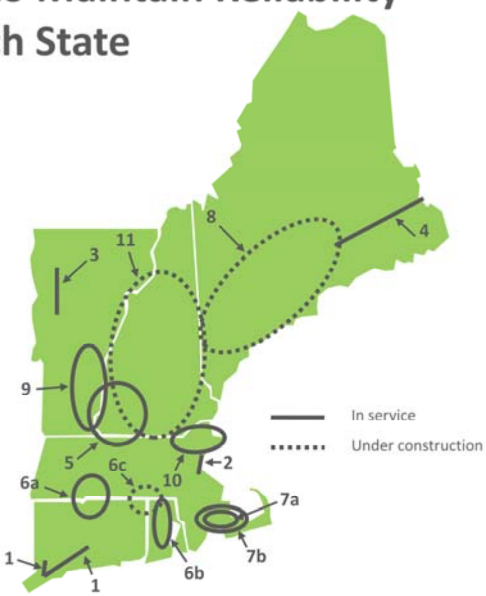
New England's Electricity Use Varies by Season

Air-conditioning and lighting loads drive seasonal peaks



Transmission Projects to Maintain Reliability Have Progressed in Each State

1. Southwest CT Phases I & II
2. Boston NSTAR 345 kV Project, Phases I & II
3. Northwest Vermont
4. Northeast Reliability Interconnect
5. Monadnock Area
6. New England East-West Solution
   a. Greater Springfield Reliability Project
   b. Rhode Island Reliability Project
   c. Interstate Reliability Project
7. Southeast Massachusetts
   a. Short-term upgrades
   b. Long-term Lower SEMA Project
8. Maine Power Reliability Program
9. Vermont Southern Loop
10. Merrimack Valley/North Shore Reliability
11. New Hampshire/Vermont Upgrades



Source: RSP Transmission Project Listing, October 2014; (does not include "concept" projects)

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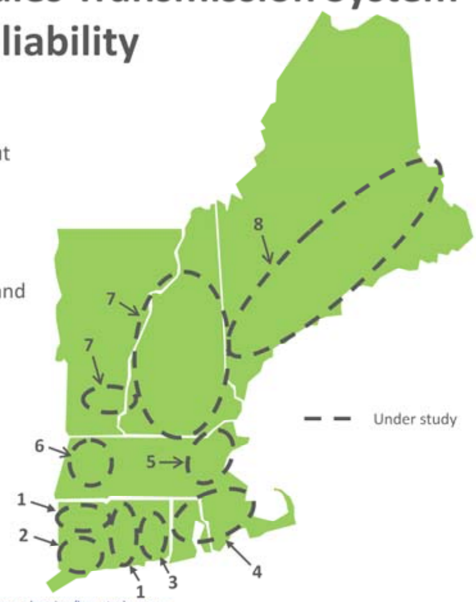
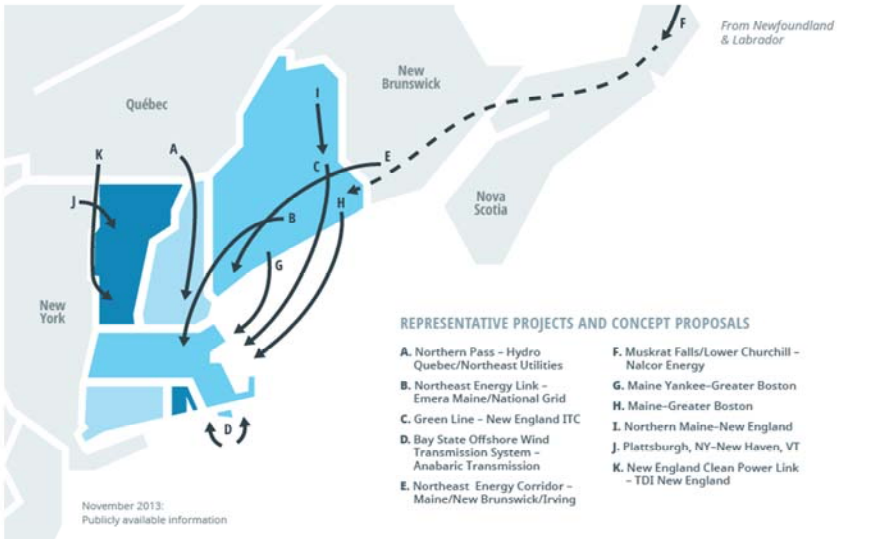
ISO Continuously Studies Transmission System Needs to Maintain Reliability

1. Greater Hartford and Central Connecticut
2. Southwest Connecticut
3. Eastern Connecticut
4. Southeast Massachusetts and Rhode Island
5. Greater Boston
6. Pittsfield and Greenfield
7. New Hampshire and Vermont
8. Maine



Source: ISO New England Key Study Areas at http://www.iso-ne.com/system-planning/key-study-areas

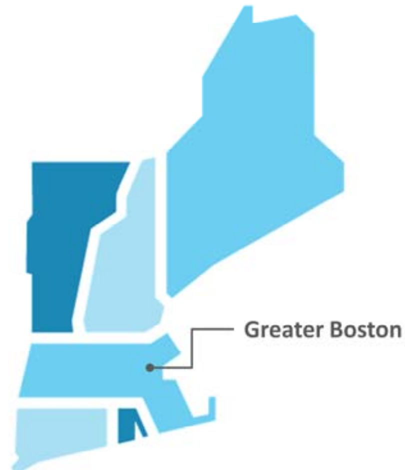
On- and Off-shore Merchant Transmission Proposals Vie to Move Renewable Energy to New England Load Centers



Note: These projects are NOT reliability projects, but ISO New England' s role is to ensure the reliable interconnection of these types of projects.

Greater Boston Area Needs Resources and Transmission

- Electricity demand is rising, while at the same time internal resources and transmission supplying the area are limited
- Generator retirements and delays to new generation projects add to challenges
- System operators are challenged given the limited transmission import capability
- Long-term transmission solutions (scheduled to be in service by the 2017–2018 timeframe) are long overdue



Greater Boston includes Boston and the North Shore

Southeastern Mass and Rhode Island Areas Need Resources and Transmission

- A SEMA/RI area study, led by the ISO, shows overloads of transmission facilities following contingencies
- Brayton Point retirement led ISO to restudy the area, and potential new FCM resources, if realized, could prompt further restudy
- ISO and stakeholders are reviewing needs and potential market resource alternatives

SEMA/RI is the area south of Boston, plus Cape Cod, and Rhode Island

FERC's Winter Market Assessment Found NE had Highest Winter Power and Natural Gas Futures

Futures Prices Elevated

	Location	2015^	2014*
Gas	Algonquin (New England)	$21.45	$11.76
Gas	Transco Zone 6 non-NY (Mid-Atlantic)	$9.09	$4.78
Gas	Dominion South (Marcellus)	$2.85	$3.66
Gas	Southern California Border	$4.30	$3.95
Gas	Henry Hub	$4.08	$3.87
Power	Massachussets Hub	$183.88	$99.88
Power	PJM Western Hub	$72.60	$44.90
Power	Northwest (Mid-C)	$37.73	$35.75
Power	Southern California (SP-15)	$46.13	$42.25

Source: Derived from ICE and Nymex data.

^January and February 2015 as of October 1 2014

*January and February 2014 as of October 1 2013

*SP-15 2014 prices from October 31 2013

*Power Note: Prices in $/MWh . Peak financial swap prices.

*Gas Note: Prices in $/MMBtu. Regional futures natural gas prices are the sum of the Henry Hub futures contract price plus the regional basis futures.

Source: FERC's Winter 2014-2015 Energy Market Assessment, October 16, 2014

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Energy Market Offer Flexibility Enhancements

- ISO and NEPOOL developed enhancements to the energy market to provide greater ***flexibility*** for market participants to adjust their supply offers in the *day-ahead* and *real-time* markets.
  - Offers may now be changed in **real time** (during the operating day)
  - Offers are now **hourly** (versus an offer for all hours of the day)
  - Offers may be **negative** (as low as -$150/MWh)
- Offers should now reflect near real-time price of fuel, improving dispatch efficiency, price formation, and incentives to follow dispatch instructions
- Enhancements went into effect on December 3, 2014

Reserve Constraint Penalty Factor Changes

- When reserves are scarce (below required amounts), real-time reserve prices are set at the Reserve Constraint Penalty Factor rates
  - The real-time reserve clearing price *is reflected in the energy price*
- Per FERC order, the Reserve Constraint Penalty Factor rates were increased
  - 30-Minute Operating Reserves from $500/MWh to $1,000/MWh
  - 10-Minute Non-Spinning Reserves from $850/MWh to $1,500/MWh
- This is also expected to enhance incentives to perform in the near-term until larger capacity market reforms take effect
- Enhancements went into effect on December 3, 2014

Problems with Existing Capacity Market Design

- *Currently*, capacity payments are linked to resource *availability* and poorly linked to resource *performance*
  - Performance means actual delivery of energy or reserves
- Consequently, supply offers do not include the value of performance
- The market doesn't distinguish between resources based on performance, hence there is little incentive for resource owners to make investments to improve performance

ISO New England's pay-for-performance proposal is a comprehensive solution

Pay for Performance

- Capacity payments will be closely tied to performance during system deficiencies—the amount of energy and/or reserves provided
- Provides strong incentives for resources to make investments that improve performance
  - Examples: more secure fuel arrangements, capital improvements, improved maintenance and staffing, etc.
- Market participants have the *flexibility* to select the best, least-cost investments to ensure performance
- Goes into effect in 2018-2019 for resources that clear in FCA #9