INVENERGY THERMALPRE-FILED DIRECT TESTIMONY
STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
ENERGY FACILITY SITING BOARD

IN RE: INVENERGY THERMAL DEVELOPMENT LLC's APPLICATION TO CONSTRUCT THE CLEAR RIVER ENERGY CENTER IN BURRILLVILLE, RHODE ISLAND

DOCKET No. SB-2015-06

PRE-FILED DIRECT TESTIMONY OF RYAN HARDY

(JUNE 30, 2017)

SUMMARY

Ryan Hardy is a member of PA Consulting Group's Management Group and testifies regarding his analysis of the regional wholesale energy market, the economic impact of CREC, including but not limited to the need and cost-justification and anticipated ratepayer savings for Clear River Energy Center ("CREC"). Mr. Hardy discusses the need for CREC in the ISO-NE market, the ratepayer savings achieved because of CREC, the emissions reductions expected in the region that will result from CREC, the compliance with other state and regional carbon emissions programs and the positive economic impacts on the Rhode Island economy expected, due to the jobs and anticipated ratepayer savings that will be created if CREC is constructed. Mr. Hardy testifies regarding the Invenergy application as it relates to the data inputs used by PA Consulting Group and the analysis provided in the memoranda and information provided in the application or in response to data questions, created by PA Consulting Group working with Invenergy and its experts and consultants, including (as to economic benefit modeling) Professor Tebaldi. In addition, Mr. Hardy updated his previous testimony to include an analysis that incorporates the latest results for the recent Forward Capacity Auction and data released by the ISO/NE. Mr. Hardy, relying on his experience and expertise in analyzing energy markets, and the materials provided in support of the Application and the analysis he performed, along with PA Consulting Group's responses to data requests, opines that the CREC will meet the energy needs of the state, as justified by long-term state and/or regional energy need forecasts and that the energy produced will be at the least possible cost to the consumer. Mr. Hardy also opines that the Project complies with State and Regional Policies and Programs, such as the Regional Greenhouse Gas Initiative and the Resilient Rhode Island Act.

LIST OF EXHIBITS

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
ENERGY FACILITY SITING BOARD

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INVENERGY THERMAL DEVELOPMENT LLC'S PRE-FILED DIRECT TESTIMONY OF RYAN HARDY, PA CONSULTING GROUP, INC.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS TITLE AND BUSINESS ADDRESS.

A. Ryan Hardy, Member of PA Consulting Group, Inc.'s ("PA") Management Group, located at 10 Canal Park, Cambridge, Massachusetts.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. My testimony is on behalf of the applicant, Invenergy Thermal Development LLC ("Invenergy"), in support of its application for a license from the Rhode Island Energy Facility Siting Board ("EFSB" or "Board") to construct the Clear River Energy Center project in Burrillville, Rhode Island ("CREC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am employed by PA Consulting Group, Inc. ("PA"), and I am a Member of PA's Management Group. I have over seventeen (17) years of experience providing energy market advisory services in support of strategic planning, generation asset financings, power company restructurings and reorganizations and power and fuel contract litigation support. I have managed the valuation process for numerous power generation asset transactions, including both thermal and renewable resources. A detailed description of my educational background and experience is in my CV, filed with the EFSB on September 12, 2016.

Q. WHAT IS PA CONSULTING GROUP?

A. PA is a global consulting, technology and innovation firm. PA is an independent firm employing approximately 2,500 people from offices across the Americas, Europe, the Nordics, the Gulf and Asia Pacific. PA works across eight industries, including energy and utilities, consumer and manufacturing, defense and security, financial services, government, healthcare, life sciences and transport, travel and logistics.

Q. CAN YOU PLEASE DESCRIBE PA CONSULTING GROUP'S EXPERIENCE WITH POWER MARKETS?

A. PA's energy economics advisors are experts across the entire energy value chain, from fuels through to power. Our energy economics advisors have refined our approach to analyzing North American power markets over the last fifteen (15) years.

Over this time period, PA has developed a robust, well-developed and industry-tested fundamental power market modeling process, including our proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA's subject matter experts and populated with assumptions based on PA's research, analytics, and experience. The results of PA's market modeling have been vetted through multiple litigation proceedings including the restructuring of Calpine and Mirant, among others.

In the last five years alone, PA has analyzed over 275 GW of power generation across various engagements in North America and over 20 GW in New England alone.

Q. PLEASE DESCRIBE YOUR EXPERIENCE PROVIDING TESTIMONY TO REGULATORY COMMISSIONS, BOARDS, AGENCIES OR AS AN EXPERT.

A. I have conducted several appraisals of power plants (approximately 5 GW) under the Uniform Standards of Professional Appraisal Practice ("USPAP") appraisal standards in a litigation context. I have also submitted testimony to the Federal Energy Regulatory Commission

("FERC") related to the financial parameters supporting PJM ISO's capacity auction construct. In 2016, I testified before the Rhode Island Public Utilities Commission ("PUC") addressing the need and cost-justification for CREC.

Q. PLEASE DESCRIBE THE SECTIONS OF THE EFSB APPLICATION THAT YOU ASSISTED WITH AND CAN SPEAK ABOUT.

A. My analysis supports the following sections of the application:

- Section 7.0 titled "Assessment of Need, as updated, including the Reports prepared by PA";
- Section 7.1.1: Conformance with State Energy Goals and Plans;
- Section 10.0 titled "Study of Alternatives".

Q. DID YOU PROVIDE WRITTEN TESTIMONY TO THE PUC REGARDING CREC IN 2016, AND WHAT WERE THE FINDINGS?

A. Yes. In summary, based on the status of my analysis at that time, following FCA ("Forward Capacity Auction") 10 and before the results of FCA 11 were known, my 2016 testimony before the PUC demonstrated that: (1) CREC is needed in the ISO-NE market; (2) CREC would save Rhode Island ratepayers approximately $210 million over the first four years of the project's commercial operations; (3) CREC would lead to significant CO_2, NO_x and SO_2 emissions reductions in the region, and specifically annual average reduction of 1.01% for CO_2, 3.12% for NOx and 3.35% for SO_2 for the New England and New York region in the 2019-2022 timeframe; and (4) CREC would have several positive economic impacts on the Rhode Island economy including creating an average of more than 660 full-time jobs per year from 2017 to 2019 and 145 full-time jobs per year from 2020 to 2034 in Rhode Island due to the facility's construction and operation. The PUC's determination confirms my analysis. (See Section III below.)

Q. HAVE YOU UPDATED YOUR ANALYSIS SINCE YOUR JULY 20, 2016 TESTIMONY BEFORE THE PUC?

A. Yes. I have recently updated my analysis that I presented to the PUC in 2016, to reflect both changes with CREC since that time, as well as changes in the ISO-NE market assumptions over the last year, particularly following the results of FCA 11 and the latest information from ISO-NE.

Q. CAN YOU SUMMARIZE THE KEY UPDATES TO YOUR MOST RECENT ANALYSIS?

A. Over the last year, several pieces of new information have been released that impact assumptions within my modeling process. In particular, I updated my analysis to reflect CREC's most recent water plan, CREC's updated construction schedule, and changes to ISO-NE market assumptions. Key changes include: **(1) Most recent water plan:** I updated my analysis to incorporate the appropriate costs associated with the new water plan; **(2) Construction schedule**: I have updated my analysis to reflect the most recent construction schedule, which includes the commercial operation of CREC Unit 1 with a June 1, 2020 online date, and Unit 2 with a June 1, 2021 online date; **(3) Market assumptions:** I have updated my analysis to include new information from the 2017 ISO-NE Forecast Report of Capacity[1], Energy, Loads, and Transmission (i.e. the CELT Report), the results of FCA 11, the results of the Connecticut and New England Clean Energy RFPs, as well as changes to natural gas prices and RGGI prices, among other assumptions; and **(4) Market structure changes from FCA 10 to FCA 11:** I have updated my analysis to include new structural changes to the capacity market, which include a reduced the Net CONE value used to set the ISO-NE demand curve as well as a new demand curve shape.

Q. WHAT ARE THE CONCLUSIONS OF YOUR UPDATED ANALYSIS?

A. While the absolute numbers have changed, the findings and magnitude of those findings are substantially consistent with my initial analysis.

[1] Attached as **Exhibit RH-1**.

CREC is needed in the ISO-NE market. CREC Unit 1 obtained a Capacity Supply Obligation with ISO-NE, and CREC Unit 2 is expected to clear FCA 12. CREC is a dual fuel facility that will use natural gas as its primary fuel and fuel oil as a backup; the dual fuel capability improves the winter reliability of the ISO-NE system. As a flexible and efficient generator, CREC will help support the integration of renewable generation on the ISO-NE grid by providing an effective resource to balance the variable nature of wind and solar. As a flexible and efficient generator, CREC will replace the impending retirements of other generation resources in the ISO-NE region.

CREC will save Rhode Island ratepayers between $122 million and $429 million between 2019 and 2024, depending on future retirements. CREC will provide electricity at the least possible cost to the consumer. The economic risk for the facility is borne by Invenergy, and not the ratepayer.

CREC will lead to significant CO_2, NOx and SO_2 emissions reductions in the region, and specifically annual average reductions of 0.95% for CO_2, 0.99% for NOx and 2.88% for SO_2 in the New England and New York region in the 2020-2025 timeframe. Upon commercial operation, CREC will be the most efficient and cleanest natural gas combined cycle generator in New England, displacing generation from dirtier sources of energy. These emission reductions will help Rhode Island meet its emission targets under both the Resilient Rhode Island Act and RGGI.

CREC will have several positive economic impacts on the Rhode Island economy including creating at a minimum an average of 683 full-time jobs per year from 2018 to 2021 and 157 full-time jobs per year from 2022 to 2036 in Rhode Island due to the facility's construction and operation.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. My testimony addresses five topics: (1) I address the need for the CREC, which includes assessment on the reliability, ratepayer savings, emissions, and economic impacts due to the addition of CREC to the ISO-NE market (**Section II**); (2) I respond to a number of the Advisory Opinions issued on CREC, including highlighting that the PUC has determined that there is a need for CREC beyond clearing the FCA (**Section III**); (3) I address a number of misleading and inaccurate statements made by the Town of Burrillville's Witness Glenn Walker (**Section IV**); (4) I address a number of misleading and inaccurate statements in testimony filed on behalf of the Conservation Law Foundation (**Section V**); and (5) I address a number of flawed statements in Conservation Law Foundation's responses to the Town of Burrillville's 1st set of data requests (**Section VI**).

II. <u>NEED FOR CLEAR RIVER ENERGY CENTER</u>

Q. PLEASE PROVIDE A SUMMARY OF YOUR ASSESSMENT OF THE NEED FOR CLEAR RIVER.

A. My analysis confirms that CREC is needed to cost-effectively maintain reliability in ISO-NE, and to support the introduction of more renewable energy projects into the ISO-NE region. I base this conclusion on both the results of ISO-NE's capacity auctions, other information from ISO-NE, and my modeling of subsequent auctions. Furthermore, as I point out below, the PUC has agreed with my assessment that there is a need for CREC.

Q. CAN YOU PLEASE PROVIDE THE BOARD AN OVERVIEW OF THE ISO-NE MARKET THAT YOU USE FOR YOUR ASSESSMENT OF THE NEED FOR CREC?

A. Yes. It is important to recognize that ISO-NE is an independent, non-profit Regional Transmission Organization ("RTO") serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. Among other items, ISO-NE is tasked with system planning, operating the power system, and administering the region's FERC approved wholesale energy, ancillary and capacity markets for members operating within these states. Members of ISO-NE, such as Rhode Island load-serving entities, rely upon the ISO-NE Forward Capacity Market ("FCM") capacity procurement mechanism. In the FCM mechanism, which was developed by ISO-NE stakeholders and approved by FERC, ISO-NE seeks to procure sufficient capacity, on both a system-wide and localized basis, three-years in advance of a Delivery Year[2] in order to meet projected peak demand *plus* minimum target reserve margins. I have prepared a more detailed overview of ISO-NE in Section 7.1 of the CREC Application, titled "Standards for Determining Need for the Proposed Facility," pages 115-116.

Q. CAN YOU PLEASE PROVIDE THE BOARD WITH AN OVERVIEW OF THE ISO-NE CAPACITY MARKET?

A. ISO-NE's FCM capacity procurement mechanism is utilized by ISO-NE market participants as a means to ensure that the ISO-NE power system has sufficient resources to reliably meet the future demand for electricity. Under the FCM, FCAs are utilized as a market-based approach to determine both system-wide and localized needs for both existing and new generation capacity through a competitive auction process designed to select the portfolio of existing and new resources needed for system-wide and local reliability with the greatest social surplus.[3] In other words, resources that clear a FCA maximize social surplus in order to meet both system-wide and local reliability needs. I have prepared a more detailed overview of ISO-NE's FCM in the CREC Application in Section 7.1.2 titled "7.1.2 ISO-NE FCM Overview and Objectives," pages 115-116.

Q. IS THE FCM THE FREE MARKET MECHANISM THAT DETERMINES THE NEED FOR NEW GENERATING UNITS IN ISO-NE'S WHOLESALE MARKETS?

[2] Within ISO-NE, a Delivery Year runs from June 1 through May 31 of the following year.
[3] Social surplus, sometimes called social welfare, is the sum of consumer and supplier surplus, which is maximized when demand equals supply.

A. Yes. As defined by ISO-NE, the FCM is the "*long-term wholesale market that assures resource adequacy, locally and system-wide. The market is designed to promote economic investment in supply and demand resources* ***where they are needed most***."[4] (Emphasis added.) Note this is fully consistent with how Invenergy described the FCM in its application before the EFSB, which Conservation Law Foundation Witness Mr. Fagan erroneously criticizes. Invenergy stated that "*Forward Capacity Auctions ("FCA") are utilized as a market-based approach to determine both system-wide and localized needs for both existing and new generation capacity through a competitive auction process designed to select the portfolio of existing and new resources needed for system-wide and local reliability with the greatest social surplus*." (EFSB Application, Section 7.1.2).

Q. ARE THERE ANY ISO-NE MARKET RULES THAT EXPLAIN HOW ISO-NE VIEWS THE FCA PROCESS AS A MECHANISM TO DETERMINE THE NEED FOR A PROJECT?

A. Yes. According to ISO-NE Market Rule 1, Section III.13.6.1.1.1, "*a Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation* ***whenever the resource is physically available***." (Emphasis added.)[5] In other words, if a resource clears an auction it has taken on a commitment to provide capacity and energy, and ISO-NE relies on that commitment in order to maintain reliability.

Also, all units that clear an FCA face a binding commitment to provide capacity in New England to maintain reliability. By clearing this type of free market auction, the ISO-NE has determined a project to be needed. Moreover, ISO-NE explicitly notes that so-called "new

[4] In ISO-NE's Introduction to New England's Forward Capacity Market ISO, pg 5 (Attached as **Exhibit RH-2)**

[5] The complete ISO-NE Section III Market Rule 1, Standard Market Design is available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

resources" that clear are needed. For example, in its press release following the FCA 10 auction (where CREC Unit 1 cleared), ISO-NE affirmed that FCA 10 "*provided the incentives for developers to bring new—**and needed**—resources to the market*."[6] (Emphasis added.)

Q. PLEASE SUMMARIZE FOR THE BOARD THE RESULTS OF ISO-NE'S FCA 10?

A. On February 8, 2016, the ISO-NE's FCA 10 concluded with 1,459 MW of new generation clearing the auction, with a system-wide clearing price of $7.03/kW-mo. The new cleared capacity generation was primarily comprised of three facilities: (1) 485 MW of Invenergy's CREC (i.e. Unit 1); (2) PSEG's 484 MW Bridgeport Harbor 6 combined cycle generation facility proposed to be located in Bridgeport, Connecticut; and (3) NRG's 333 MW Canal 3 peaking facility proposed to be located in Sandwich, Massachusetts.

Q. IN CLEARING FCA 10 DID CREC UNIT 1 RECEIVE A CAPACITY SUPPLY OBLIGATION FOR ONLY ONE YEAR?

A. No. CREC Unit 1 received what is known as a 'seven year lock' from ISO-NE. This seven year lock amounts to a Capacity Supply Obligation for a seven year time period.

Q. DOES THE FACT THAT ISO-NE PROCURED CAPACITY ABOVE THE ISO-NE NET INSTALLED CAPACITY REQUIREMENT ("NICR") IN FCA 10 MEAN THAT CREC IS NOT NEEDED?

A. Absolutely not. As I explained above, all units that clear an FCA, such as FCA 10, including CREC Unit 1, face a binding commitment to provide capacity in New England to maintain reliability of the regions electricity markets. By clearing the auction, Clear River was determined by the free market to be needed. Moreover, ISO-NE explicitly stated after FCA 10 that the new resources that cleared FCA 10 are needed. In its press release following the auction, ISO-NE affirmed that FCA 10 "*provided the incentives for developers to bring new—**and needed**—*

[6] ISO-NE. Press Release: ISO-NE Capacity Auction Secures Sufficient Power System Resources, At a Lower Price, for Grid Reliability in 2019-2020. February 11, 2016. p 1, copy attached as **Exhibit RH-3**.

resources to the market."[7] (Emphasis added.) In its Advisory Opinion before the Board, the Rhode Island PUC agrees, stating plainly that "*Resources acquired above the Net Installed Capacity Requirement are needed*."

Q. WHY DID ISO-NE PROCURE CAPACITY ABOVE THE NICR?

A. The NICR is the minimum amount of capacity needed to meet ISO-NE's reliability target. However, meeting the NICR is only one component of need. ISO-NE's FCM is designed to determine need not just in terms of meeting the absolute minimum amount of capacity needed to maintain reliability, but also to maximize the overall value to the ratepayer. ISO-NE calls this maximization of value, maximizing social surplus.

Q. DOES THAT MEAN ISO-NE DETERMINED IN FCA 10 THAT THERE WAS A NEED FOR CAPACITY ABOVE THE NICR TO MAXIMIZE SOCIAL SURPLUS?

A. Yes. When the marginal supply offers in the auction do not perfectly correspond with the NICR, the FCA process evaluates every possible combination of supply offers in the auction to maximize social surplus. Ultimately, ISO-NE selects the most optimal economic solution that meets or exceeds the NICR. Removing a resource that is part of the most optimal economic solution by definition creates a less optimal economic outcome for the ratepayer and greater risk that the needed resources and value will not be delivered to the ratepayer. In other words, all cleared capacity in an FCA is needed by ISO-NE in order to maximize the value for the ratepayer in meeting its reliability target, and the ISO-NE specified that Invenergy cleared 485 MW in the FCA 10.

Q. IN SUMMARY, YOU ARE SAYING CLEAR RIVER'S CLEARED CAPACITY IS NEEDED BY ISO-NE TO ENSURE RELIABILITY AND MAXIMIZE SOCIAL SURPLUS FOR RATEPAYERS?

[7] ISO-NE. Press Release: ISO-NE Capacity Auction Secures Sufficient Power System Resources, At a Lower Price, for Grid Reliability in 2019-2020. February 11, 2016. p 1, copy attached as **Exhibit RH-3**.

A. Yes.

Q. PLEASE SUMMARIZE FOR THE BOARD THE RESULTS OF ISO-NE'S FCA 11?

A. On February 6, 2017, the ISO-NE's FCA 11 concluded with a system-wide clearing price of $5.30/kW-mo. There was an increase of 269 MW in cleared capacity relative to FCA 10 in the previous year. The majority of the increase was from Passive Demand Resources, or energy efficiency, which cleared 422 MW more than in FCA 10. Additionally, there was an increase of 7 MW of cleared wind and solar resources (11 MW of new wind and solar resources), and a decrease of 214 MW of cleared import capacity. The remainder of the difference in cleared capacity from FCA 10 is from uprates and de-rates[8] to existing generation resources as well as some minor retirements.

Q. IS IT YOUR ASSESSMENT THAT CREC IS NEEDED FOR RELIABILITY IN THE ISO-NE MARKET?

A. Yes. To begin, capacity that clears an FCA is by definition a very strong indication of need. It is undisputed that approximately half of CREC's capacity cleared FCA 10, which indicates that this capacity is needed to maintain reliability in ISO-NE.

Q. GIVEN THE FACT THAT CREC UNIT 2 DID NOT CLEAR FCA 11, IS THERE STILL A NEED FOR THIS ADDITIONAL CAPACITY IN YOUR ASSESSMENT?

A. Yes. There are several forms of need within ISO-NE and Rhode Island specifically. For example, ISO-NE needs additional efficient natural gas capacity that can start quickly, such as CREC, to maintain reliability (particularly in an import-constrained zone that Rhode Island is a part of), to support the further development of intermittent renewable energy resources, and also to replace additional retirements in the ISO-NE market. Within my testimony I highlight other

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[8] A capacity uprate is an increase in capacity at an existing unit, which typically occur due upgrades (i.e. the installation of new equipment at a facility or improved maintenance). In contrast, a capacity derate is a reduction in a facility's capacity, which often occur due to unexpected physical problems at a facility.

needs such as ratepayer savings, emission reductions, and economic benefits. The PUC in its Advisory Opinion agrees that there are a number of factors determining the need for the full CREC facility, which I discuss further in Section III.

Q. YOU STATED YOUR ASSESSMENT THAT THE CREC WOULD HELP SUPPORT THE FURTHER DEVELOPMENT OF RENEWABLE ENERGY RESOURCES IN THE ISO-NE REGION, INCLUDING RHODE ISLAND. PLEASE ELABORATE?

A. Yes. Flexible and efficient generation, such as CREC, broadly helps ensure reliability is maintained in a least-cost and efficient manner. However, flexible generation is also critically important in markets with the expansion of variable and intermittent renewable energy, such as wind and solar. For example, wind generation's intermittent and at times unpredictable nature (e.g., wind ramp-down events where wind stops blowing suddenly) requires flexible generation that can ramp up quickly to respond to changes in wind generation in order to maintain reliability. The same is true for other variable non-dispatchable generation such as solar. ISO-NE has recognized this system need. In the ISO's 2017 Regional Energy Outlook[9], ISO-NE states that New England's *"generation fleet will need to include fast, flexible power plants ready to jump in and balance the variable output from wind and solar resources; these will likely be natural gas-fired generators…because of their ability to turn on and off quickly"*(Page 18). As a new highly flexible resource, CREC will help ISO-NE be able to more reliably integrate renewable resources across the New England footprint, including in Rhode Island.

Q. WHAT GEOGRAPHIC AREA DID PA CONSIDER IN ITS UNDERLYING ANALYSIS AND MODELING IN SUPPORT OF THIS APPLICATION?

A. PA modeled the entire Eastern Interconnect, focusing in on the ISO-NE and New York ISO ("NYISO") regions.

[9] Attached as **Exhibit RH-4**.

Q. WHY DID PA SELECT TO REPORT ON THIS GEOGRAPHIC REGION INSTEAD OF RHODE ISLAND ONLY?

A. Rhode Island is part of the broader ISO-NE market, which is an integrated electric system that centrally dispatches electricity across the New England region (i.e., across ISO-NE). Due to this integrated nature, it would be inappropriate to report the impacts of CREC on just Rhode Island specifically. PA also considered NYISO because New York is a party to the RGGI, and due to the high degree of interconnectivity (approximately 2 GW of transfer capability) between ISO-NE and NYISO.

Q. DOES REPORTING THESE GEOGRAPHIES AMOUNT TO CHERRY PICKING?

A. Absolutely not. This is the most appropriate way to represent the electricity system and impacts on greenhouse gas emissions. The ISO-NE and NYISO footprints have a high degree of interconnectivity and seams agreements (i.e. agreements that coordinate how the two markets interact within one another) that help to facilitate the participation of a resource in either markets' wholesale energy and capacity markets. For example, on December 16, 2015, ISO-NE and NYISO went live on a new interregional market system to streamline energy exchanges between the two ISOs by utilizing Coordinated Transaction Scheduling ("CTS") which enables the more efficient use of interregional transmission lines and, therefore, better access to the lowest-cost source of power between the two regions. In other words, it is incorrect to look at the operation of ISO-NE as an "island" from an electricity market perspective, and one needs to consider surrounding impacts (including emissions impacts).

<u>II (a). RATEPAYER IMPACTS</u>

Q. WILL CREC LOWER WHOLESALE POWER COSTS TO RHODE ISLAND RATEPAYERS?

A. Yes, absolutely. Following FCA 10, PA determined that the presence of CREC was projected to save Rhode Island ratepayers approximately $210 million. As I describe in more detail below, following the FCA 11 results, our latest analysis shows that the presence of CREC is projected to save Rhode Island ratepayers between $122 million and $429 million.

Q. WHY DO YOU FORECAST RATEPAYER SAVINGS FOR CAPACITY AND ENERGY FROM 2019 TO 2024?

A. My updated analysis relied on the same modeling methodology that I used in my initial analysis, which focused on the first four years of CREC's operations (2019-2022). However, I would expect continued emissions and ratepayer energy costs savings over a much longer timeframe.

In my revised analysis as part of this Direct Testimony, I have focused on the 2019 to 2024 time period due to the projected online dates resulting from CREC having been delayed to June 2020 for CREC 1 and June 2021 for CREC 2. I have extended the tenor of my analysis to 5 years (2020 through 2024) to capture the first four years of operation of both units. I have also included the FCA 10 time period due to the impact CREC had on FCA 10 capacity prices in the 2019/20 ISO-NE delivery year.

Q. HOW ARE THESE MILLIONS OF DOLLARS IN SAVINGS TO THE RHODE ISLAND RATEPAYERS CALCULATED? FOR EXAMPLE, HOW DO THE SAVINGS BREAK DOWN BETWEEN CAPACITY AND ENERGY COST SAVINGS?

A. Cost savings to the ratepayer will accrue primarily through wholesale capacity and energy markets. The $122 to $429 million rage represents the difference in total capacity and energy costs to Rhode Island-only load resulting from the CREC capacity addition, as measured by comparing cost results from capacity and energy modeling cases (a) with CREC coming online in two stages: June 2020 (485 MW) and June 2021 (an additional 485 MW); and (b) without CREC. The differences between these two cases represent the savings to the ratepayers.

With CREC, capacity cost savings to Rhode Island ratepayers were calculated to be $72 million to $379 million from 2019-2024, or $12 million to $63 million annually on average. Also, energy cost savings to Rhode Island ratepayers were calculated to be $50 million for 2020-2024, or approximately $10 million annually.

Q. WHY WILL CREC RESULT IN CAPACITY MARKET SAVINGS TO THE RHODE ISLAND RATEPAYER?

A. ISO-NE's FCM capacity procurement mechanism is utilized by ISO-NE market participants as a means to ensure that the ISO-NE power system has sufficient resources to reliably meet the future demand for electricity. Resources that clear an FCA are the resources that maximize social surplus in order to meet both system-wide and local reliability needs. Stated simply, as supply gets tighter (i.e., reserve margins decline), capacity prices will increase, all else being equal. When new generation capacity enters the market it increases the reserve margin, which, all else equal, results in lower capacity prices, thereby saving ratepayers money.

Q. WHY WILL CREC RESULT IN ENERGY MARKET SAVINGS TO THE RHODE ISLAND RATEPAYER?

A. CREC will be a very efficient combined cycle facility. It will generate low-cost energy that will displace higher cost generation, including output from coal-, oil-, and less efficient natural gas-fired facilities (a list that would include almost all existing natural gas-fired generation in New England). Stated simply, CREC will reduce system energy costs and save ratepayers money, and we know from my analysis that the energy cost savings to Rhode Island ratepayers will be significant.

Q. DID THE ANALYSIS CONDUCTED BY PA CONSIDER ALL RELEVANT COMPLIANCE COSTS ASSOCIATED WITH EMISSIONS PROGRAMS INCLUDING RGGI, CLIMATE CHANGE (RESILIENT RHODE ISLAND ACT) AND OTHER EMISSIONS PROGRAMS?

A. Yes, PA's analysis included all compliance costs associated with existing emissions programs, for both CREC and all other generating facilities located within the geographic footprint analyzed by PA. For example, PA's analysis includes compliance costs for the RGGI program, and compliance costs associated with the EPA's Cross State Air Pollution Rule ("CSAPR") for SO_2 and NOx emissions.[10] Given that there are no explicit compliance programs related to the Resilient Rhode Island Act that have been proposed and/or promulgated, PA has not included any specific compliance costs associated with this law.

Q. CAN YOU EXPLAIN CREC'S IMPACT ON RATEPAYERS COSTS PRIOR TO 2020?

A. Yes. While CREC is not projected to be online until June 1, 2020 (for the 2020/21 Delivery Year), the fact that CREC Unit 1 cleared in FCA 10 (for the 2019/20 Delivery Year) depressed the overall capacity price in FCA 10. In other words, FCA 10 cleared at a lower price than it would have without CREC Unit 1 providing Rhode Island customers with approximately $39 million of capacity cost savings for the 2019/20 Delivery Year.

Q. WHY HAVE YOU PROVIDED A RANGE OF SAVINGS IN THIS ANALYSIS?

A. There is significant uncertainty related to ISO-NE's capacity supply. In particular, there is a significant amount of capacity at risk for retirement. Due to the relatively small size of ISO-NE's market, relatively small changes in supply can have a material impact on capacity prices.

Q. FOR THE LOW END OF YOUR RANGE, WHAT ASSUMPTIONS DID YOU MAKE REGARDING PENDING RETIREMENTS IN YOUR UPDATED ANALYSIS?

A. I did not assume any additional firm retirements of existing units beyond those that have already been announced with firm retirement dates. The units with firm retirement dates include:

[10] Note that the CSAPR program does not directly impact the ISO-NE footprint (or generators located therein) due to the fact that the rule's coverage area does not extend north of New York.

New Boston CT (16 MW in 2017), Brayton Point 1-4 & IC (1,544 MW in 2017), Pilgrim (683 MW in 2019), and Bridgeport Harbor 3 (383 MW in 2021). My analysis did not assume the retirement of any of the 5,500 MW of capacity at risk for retirement that ISO-NE identifies in the 2017 Regional Energy Outlook[11], nor the 1,280 MW of static delist bids submitted in FCA 11 that did not exit the market, nor the possibility for 1,044 MW of Public Service of New Hampshire ("PSNH") units to retire if Eversource Energy is ultimately unable to sell them.

Q. YOU JUST REFERENCED THE TERMS "STATIC DELIST BID". PLEASE EXPLAIN TO THE BOARD WHAT THAT MEANS AND WHY IT IS IMPORTANT TO YOUR ANALYSIS.

A. ISO-NE's market rules limit how power plants that have previously cleared a FCA may participate in future FCAs. One of these limitations is knowns as the 'dynamic delist bid threshold.' Within any FCA, unless granted an exemption, existing resources that have previously cleared an auction are not allowed to exit the market at prices above the dynamic delist bid threshold. It is assumed that power plants that receive capacity prices at or above the dynamic delist bid threshold are able to recover fixed costs at this level of pricing. Once the dynamic delist bid threshold is reached, any existing resource is able to exit the market. However, for some power plants, the dynamic delist bid threshold is actually below the amount of revenue necessary to meet the plant's fixed costs. ISO-NE allows generators in this situation to apply for special permission to exit the market at higher capacity prices. Those power plants are required to undergo a rigorous cost justification process before ISO-NE's independent market monitor to validate a higher exit price. This higher exit price is what is known as a 'static delist bid.' In short, a static delist bid is a unit specific price at which a specific power plant is allowed to exit the market.

[11] Attached as **Exhibit RH-4.**

While there were 1,522 MW[12] of static delist bids submitted as part of FCA 11, not all of that capacity ultimately exited the market. There was approximately 1,280 MW of static delist bids submitted in FCA 11 that ultimately stayed in the market during FCA 11. This capacity is likely highly vulnerable for future retirement.

Q. HOW WOULD YOUR RESULTS CHANGE IF SOME OF THE "AT RISK" UNITS IN THE ISO-NE REGION WERE TO RETIRE?

A. To be clear, and I cannot overstate this, if additional units were to retire before 2021, the capacity prices savings due to CREC would be materially higher. I use FCA 12 as an example to demonstrate how CREC would provide material savings for Rhode Island ratepayers. If the NRG unit Montville (approximately 500 MW), which submitted a delist bid in FCA 11, were to retire, the potential increase in pricing if CREC did not enter would be $2.08/kw-mo. This capacity price impact would translate to $61 million in incremental ratepayer savings in FCA 12 alone. If the PSNH units (1,044 MW), which are supposed to retire if Eversource Energy is unable to sell them, were to retire, the potential increase in pricing if CREC did not enter would be $2.82/kw-mo. This would translate to $80 million in incremental ratepayer savings in FCA 12 alone. If the PSNH units and Montville (approximately 1,500 MW in total) were to retire, the potential increase in pricing if CREC did not enter would be $3.50/kw-mo. This would translate to $96 million in incremental ratepayer savings in FCA 12 alone.

In other words, there would be material additional ratepayer savings due to CREC if as little as 500 MW were to retire from the ISO-NE market, and there are over 5,500 MW of capacity that ISO-NE identifies as currently at risk for retirement, according to ISO-NE's 2017 Regional Electricity Outlook[13].

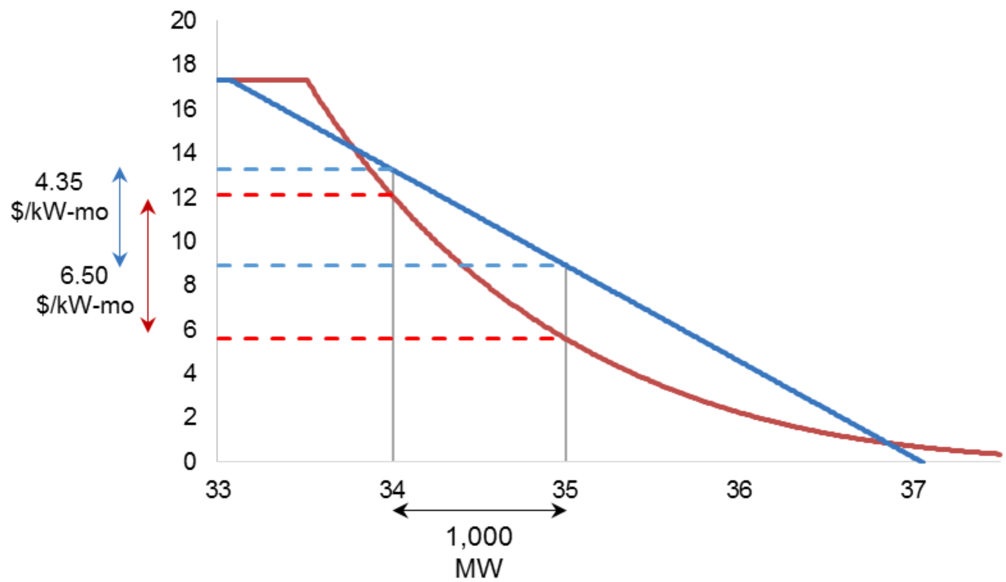
[12] A total of 1,622 MW of delist bids were submitted, which includes 100 MW of export delist bids
[13] Attached as **Exhibit RH-4**.

Q. WHY IS THE LOW END OF YOUR RANGE BELOW THE VALUE IN YOUR PREVIOUS ANALYSIS?

A. There are a number of contributing factors for the difference between my analyses, but the majority of the reduction in ratepayer savings is attributable to structural changes in the capacity market. In particular, ISO-NE reduced the Net CONE value used to set the ISO-NE demand curve by approximately 30%, from $11.64/kW-mo in FCA 11 to $8.04/kW-mo in FCA 12. The Net CONE value is used by the ISO to set the demand curve, and it is the theoretical value required by a new entrant. All else equal, a reduction in the Net CONE lowers the expected capacity price resulting from the FCA. The low end of my ratepayer savings would be significantly higher if ISO-NE did not make this change.

The primary reason that the low end of my range would be higher than my previous analysis (if ISO-NE did not reduce the Net CONE) is due to the steeper slope of the demand curve under the convex structure. With this change, in general there is greater savings to ratepayers for each additional MW of capacity, as demonstrated in Figure 1. For example, based on FCA 10 demand curves that were published by ISO-NE, a 1,000 MW shift in cleared capacity would have a larger impact on the clearing price under the new convex shape of the demand curve than the old linear shape. The 1,000 MW shift equates to a drop in price of $6.50/kW-mo under the new convex demand curve, but only a $4.35/kW-mo drop in price under the old linear demand curve. ISO-NE made this change to better reflect the true reliability value of capacity, which is higher than what the previous linear demand curve implied.

Figure 1: Indicative FCA 10 Demand Curves



Note that in my analysis, I expect capacity prices to stay at or above ISO-NE's view of what an old, inefficient steam gas unit needs from the capacity market to cover its fixed costs net of energy margins. I believe this to be a conservative assumption when calculating ratepayer savings. If I did not assume this, capacity prices would drop even further in the case with CREC.

Q. FOR THE UPPER END OF YOUR RANGE, WHAT ASSUMPTIONS DID YOU MAKE REGARDING PENDING RETIREMENTS IN YOUR UPDATED ANALYSIS?

A. In addition to the retirement assumptions made in my analysis of the low end of my range, I also assumed the 1,044 MW of PSNH units would retire.

Q. WHY DID YOU SELECT THESE UNITS FOR RETIREMENT?

A. There are significant economic pressures on older generation units within ISO-NE. These include, but are not necessarily limited to, the 5,500 MW of capacity identified by ISO-NE in its 2017 Regional Energy Outlook. We have already seen 1,280 MW of static delist bids submitted in FCA 11, which is an indicator that these units could exit the market.

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I selected the PSNH units due to (i) the mandate that these units must retire if they are not sold through an auction process approved by the NH PUC, and (ii) that the 1,044 MW of the PSNH units is a lower capacity value than the 1,280 MW of static delist bids in FCA 11—this provides a conservative view of potential retirements. Overall, the important takeaway to understand here is that the capacity price savings can increase significantly with any number of retirements playing out in the market. Stated another way, without the addition of CREC, electric rates could increase substantially for Rhode Island and ISO-NE customers.

Q. WHAT IS THE STATUS OF THE SALE PROCESS FOR THE PSNH UNITS?

A. The PSNH units are being sold as part of an auction process. Currently, bids have been received and a decision is expected by late summer 2017. If there are no successful bidders and Eversource Energy is ultimately unable to sell them through a subsequent auction process, they will retire per order of the New Hampshire PUC. However, if these units do not retire, it is still highly reasonable to assume that a subset of the 5,500 MW at risk units within ISO-NE may retire, as all of the 5,500 MW is vulnerable for retirement.

II (b). EMISSIONS IMPACTS

Q. WILL CREC LOWER CO2 EMISSIONS?

A. Yes, absolutely. My previous analysis projected CREC would lead to annual average emissions reductions from 2019-2022 of 1.01% for CO_2, 3.12% for NOx and 3.35% for SO_2 for the New England and New York region. My most recent analysis shows that CREC will lead to an annual average emission reductions reduction of 0.95% for CO2, 0.99% for NOx and 2.88% for SO_2 for the New England and New York region.

Q. WHAT METHODOLOGY DID YOU USE TO CALCULATE THESE VALUES?

A. My emissions analysis relied on the same modeling that I conducted for my ratepayer savings analysis, which primarily focused on the first 5 years of CREC's operations (2020-2024).

To be consistent, I used the same time period for emissions reductions. However, I would expect continued emissions and ratepayer energy costs savings over a much longer timeframe.

Q. HOW DOES THE ADDITION OF A HIGHLY EFFICIENT NATURAL GAS COMBINED CYCLE FACILITY LOWER ENVIRONMENTAL EMISSIONS?

A. The net system-wide decrease is largely driven by highly efficient natural gas-fired combined cycle generators, such as CREC, requiring less fuel per unit of energy generated than less efficient competing generators. This results in both emissions and economic advantages relative to existing generators. As such, CREC will displace less efficient (and less environmentally-friendly) resources that are currently dispatched on the power system.

Q. WHAT IS THE REGIONAL GREENHOUSE GAS INITIATIVE "RGGI"?

A. RGGI is the first market-based regulatory program in the United States explicitly directed at reducing greenhouse gas emissions from the power sector. It is a cooperative cap-and-trade program among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont. RGGI recognizes that greenhouse gas emissions are a global issue, and not a localized emissions issue.

Q. IS RHODE ISLAND PARTY TO RGGI?

A. Yes. Rhode Island was a leader by participating in the initial negotiations that informed the original memorandum of understanding that formed RGGI in 2005, and officially signed on to RGGI with the General Assembly's passage and Governor's signature of The Implementation of the Regional Greenhouse Gas Initiative Act of 2007.

Q. DOES THE IMPLEMENTATION OF RHODE ISLAND'S REGIONAL GREENHOUSE GAS INITIATIVE ACT REQUIRE RHODE ISLAND'S PARTICIPATION IN RGGI?

A. Yes.

Q. WHAT IS THE LEGISLATIVE INTENT OF THE IMPLEMENTATION OF THE REGIONAL GREENHOUSE GAS INITIATIVE ACT?

A. According to the Legislative Findings under § 23-82-2 of the Act, "*Rhode Island's implementation of the Regional Greenhouse Gas Initiative, (hereinafter referred to as "RGGI"), should be managed to maximize the state's contribution to lowering carbon emissions while minimizing impacts on electric system reliability and costs to Rhode Island power consumers over the long term*." Additionally, the legislative findings include that "*it is the intent of the General Assembly in enacting this chapter that the state of Rhode Island shall fulfill the mutual understandings and commitments of the regional greenhouse gas initiative so that the state may fully participate in that initiative and all sales or auctions and other proceedings as may be established under that initiative*."

Q. DOES THE ADDITION OF CREC HELP RHODE ISLAND LOWER REGIONAL CARBON EMISSIONS WHILE MINIMIZING IMPACTS ON ELECTRIC SYSTEM RELIABILITY?

A. Yes. As I demonstrated above, the addition of CREC is necessary for system reliability, and will also help lower regional carbon emissions.

Q. WILL THE ADDITION OF CREC NEGATIVELY IMPACT THE ABILITY OF RHODE ISLAND OR NEW ENGLAND TO MEET BINDING CO2 EMISSION REDUCTION TARGETS?

A. No. As a participant in the RGGI, all thermal generators greater than 25 MW located within Rhode Island are subject to RGGI program CO_2 emissions caps. As such, the addition of CREC will not impact the overall emissions reduction goals of RGGI given its emissions are also accounted for under the RGGI cap. Moreover, given the likelihood that the addition of CREC will actually lead to an overall decrease in regional CO_2 emissions given the high efficiency of the unit, it may lead to an overall less costly compliance trajectory for the region under the RGGI program. In other words, the addition of CREC could help save Rhode Island ratepayers costs associated with the state's participation in the RGGI program.

Q. WILL THE CREC PROJECT HELP RHODE ISLAND MEET ITS GOALS SET FORTH IN THE RESILIENT RHODE ISLAND ACT?

A. Yes. The CO_2 emission reductions will help Rhode Island meet its emission targets under the Resilient Rhode Island Act. I describe this in more detail in Section V below.

II (c). ECONOMIC IMPACTS

Q. DID YOU ANALYZE THE ECONOMIC IMPACT OF CLEAR RIVER ENERGY CENTER?

A. Yes, PA was retained to evaluate the economic development impacts resulting from the construction and ongoing operation of CREC.

Q. IN COMPLETING THIS ECONOMIC ANALYSIS, DID YOU COLLABORATE WITH ANY RHODE ISLAND EXPERTS ON THE TOPIC? IF SO, WHO?

A. Yes, PA collaborated with Professor Edinaldo Tebaldi. Dr. Tebaldi is an associate professor of economics at Bryant University. He also serves as the Rhode Island forecast manager for the New England Economic Partnership ("NEEP"). He is an applied econometrician with research interests in economic growth, development and labor market outcomes. Dr. Tebaldi has published several articles in refereed journals and co-authored a number of economic impact assessment studies and reports analyzing economic conditions across New England States.

Q. PLEASE DESCRIBE THE METHODOLOGY EMPLOYED TO ESTIMATE THE ECONOMIC IMPACTS?

A. To estimate the magnitude of the resulting economic impacts, the study uses input-output ("I-O") analysis. I-O analysis accounts for inter-industry relationships within a city, state or expanded area, and employs the resulting economic activity multipliers to estimate how the local economy will be affected by a given investment (in this case, the construction and ongoing operation of the CREC facility).

Multiplier analysis is based on the notion of feedback through I-O linkages among firms and households who interact in regional markets. Firms buy and sell goods and services to other firms and pay wages to households. In turn, households buy goods from firms within the economic region. Thus, the economic impact of CREC spreads to other local businesses through direct purchases from them as well as from purchases of locally produced goods and services that are made using the income derived by the employment that has been created. Further impacts occur because of feedback effects – where other local firms require more labor and inputs to meet rising demand for their output, which has been stimulated by CREC's construction and operation.

The economic impact of CREC's construction and operation can be categorized as follows: **(1) Direct Effects** – Jobs, income, output and fiscal benefits that are created directly by the construction and ongoing operations of CREC. The jobs (and other benefits) that are created may be short-term, as in the case of construction jobs, or long-term, such as the operations and maintenance positions that exist throughout the life of the generation facility; **(2) Indirect Effects** – Jobs, income, output and fiscal benefits that are created throughout the supply chain and that are spawned by the direct investment to build and operate the facility. Indirect jobs include the jobs created to provide the materials, goods, and services required by the construction and operation of CREC, as well as the jobs created to provide the goods and services paid for with the wages from the direct jobs; **and (3) Induced Effects** – Jobs, earnings, output and fiscal benefits created by household spending of income earned either directly from CREC or indirectly from businesses that are impacted by CREC.

Q. WAS THE ANALYSIS COMPLETED USING ANY MODELS OR SOFTWARE DESIGNED FOR THIS TYPE OF ECONOMIC ANALYSIS?

A. Yes, the job creation, earnings and overall economic impact of CREC on Rhode Island were analyzed using project cost specifics and two I-O models: IMPLAN[14] and the National Renewable Energy Lab's Jobs and Economic Development Impact model ("JEDI").

IMPLAN is an economic analysis tool that takes data from multiple government sources and employs an estimation method based on industry accounts or I-O Matrix that allows, using multipliers, to make estimations of how changes in income and spending impact the local economy. IMPLAN estimates are generated by interacting the direct economic impact of CREC with the Regional Input-Output Modeling System (RIMS II) multipliers for Rhode Island. The United States Bureau of Economic Analysis ("BEA") provides these multipliers.

The JEDI model estimates the economic impact of constructing and operating power generation plants at the state level. The JEDI model also uses an I-O methodology and relies on economic multipliers derived from IMPLAN. The JEDI model allows estimating of the economic impact of power generation investment in a state including local labor, services, materials, other components, fuel and other inputs. The model also allows adjusting the portion of project investment that occurs locally.

Q. WILL THE PROJECT HAVE A POSITIVE ECONOMIC IMPACT ON THE STATE OF RHODE ISLAND? WHAT IS THE SOURCE OF THESE ECONOMIC IMPACTS?

A. Yes. As is typical of generation facilities like CREC, the project will create a significant number of jobs and income for Rhode Island workers and will have a very positive impact on the Rhode Island economy. These economic development impacts will result from the following three areas:

[14] IMPLAN Group LLC, IMPLAN System (data and software), 16905 Northcross Dr., Suite 120, Huntersville, NC 28078 www.IMPLAN.com.

1. Construction of the facility – Equipment, materials and labor employed during construction as well as state sales tax, permitting fees and other activities.
2. Ongoing operation of the facility – Fixed and variable costs associated with the materials and labor needed to operate the facility as well as annual property taxes.
3. Power market cost savings to Rhode Island ratepayers – The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices, thereby driving significant savings to Rhode Island ratepayers. In addition to direct cost savings, PA has evaluated the induced economic effects on the Rhode Island economy associated with these electricity customer cost savings.

Q. WHAT WAS THE SOURCE OF THE LABOR AND COST INPUTS?

A. Cost and labor inputs related to the construction and ongoing operation of the facility were provided by Invenergy. Wholesale power markets savings – the reinjection of ratepayer savings into the economy resulting in induced impacts to the Rhode Island economy – were calculated using PA's projected energy and capacity market prices.

Q. WHAT ARE THE ESTIMATED ECONOMIC IMPACTS OF THE CONSTRUCTION AND OPERATION OF THE CREC ON THE STATE OF RHODE ISLAND?

A. The construction and ongoing operation of CREC will create hundreds of jobs and drive well over $1 billion in economic development in Rhode Island from 2018-2036. The direct economic impacts themselves will be significant, realized in the form of jobs, income, output and benefits created directly by the construction and ongoing operations of CREC. In addition, CREC will generate significant economic activity in Rhode Island through I-O linkages among firms and households who are affected by its construction and operations. Ongoing facility operations will create an additional 23 onsite (direct) jobs and approximately $2 million in earnings annually from 2022 through 2036. Note that these figures do not include the jobs and earnings associated with the many professionals who will be employed throughout the diverse supply chain that will support the facility's operation and maintenance.

The total impact of CREC on the Rhode Island economy, including all direct, indirect and induced economic activity, will be considerably larger. In summary, the job creation, earnings, and overall economic impact of the project on the state of Rhode Island are anticipated to be extremely beneficial both to individuals and to the economy.

My updated analysis is consistent with my previous analysis (provided in the Application at Section 5.0) that CREC will have several positive impacts to the Rhode Island economy. My updated analysis shows the following projections:

Rhode Island jobs. From 2018-2021, which includes the construction period, the first 1.5 years of operation of CREC Unit 1, and the first partial year of operation of CREC Unit 2, CREC will support the creation of 683 full-time jobs per year, on average. The construction and operation of CREC alone – i.e., not including the electricity cost savings to the customer – will create an average of more than 605 full-time jobs per year from 2018-2021 and 129 full-time jobs per year from 2022 to 2036 in Rhode Island.

Rhode Island earnings. From 2018-2021, CREC will support the creation of nearly $310 million in earnings to Rhode Island workers, or more than $75 million per year, on average. Earnings to Rhode Island employees as a result of CREC will total more than $520 million from 2018-2036.[15]

Rhode Island economic output. From 2018-2021, the total economic impact on Rhode Island is projected to be more than $530 million, or approximately $133 million per year. The

[15] The analysis assumes 41 months of construction and a June 2020 commercial online date for Unit 1 and a June 2021 online date for Unit 2.

overall impact of CREC on the Rhode Island economy will total more than $1 billion from 2018-2036, or an average of over $60 million annually.

The conclusions of my original analysis have been supported by Planning in its original Advisory Opinion. Planning enlisted the support of the Office of Management and Budget ("OMB") to conduct additional analysis, including multipliers, to estimate the economic impact of CREC. Based on OMB's projections from its own analysis, Planning concludes (Page 13), "*that the magnitude of the employment, earnings, and economic output benefits described by Invenergy are reasonable, or even low, and consistent with a finding of positive economic impact for the state*." Since my updated analysis is consistent with the analysis reviewed by OMB, I would expect their conclusions to remain unchanged.

It is important to note that the most significant economic impacts will be realized in the early years of the project: the construction of CREC will bring significant investment and construction activity to Rhode Island from 2018 to 2021.

Q. HAVE THE DESIGN SPECIFICATIONS AND CONSTRUCTION SCHEDULE ASSUMED CHANGED SINCE YOUR ORIGINAL ECONOMIC ANALYSIS WAS COMPLETED?

A. Yes. The facility as currently planned is substantially very similar to the facility envisioned at the time of the economic analysis, but there have been changes to the planned capacity and the construction schedule, and subsequently to the total projected savings to Rhode Island ratepayers that warrant noting and that I have included in my most recent analysis.

- **Planned capacity** – The original economic impact analysis was completed assuming a 1,000 MW combined cycle facility, while the facility is now expected to be approximately 970 MW.

- **Construction schedule** – The original economic impact analysis was completed assuming that the plant would be constructed in a single 30-month timeframe and commence commercial operation in June 2019. However, the plant is now expected to be built in two stages over 41 months – 485 MW, in a 1x1x1 configuration, is projected to come online in June 2020, and an additional 485 MW will come online in June 2021, when the plant is expanded to a 2x2x2 configuration.
- **Savings to ratepayer** – The current economic impact analysis assumes that CREC results in $122 million in savings to the Rhode Island ratepayers from 2019-2024, which is based off of the lower end of my ratepayer savings range discussed earlier in my testimony. Given CREC's updated construction schedule, it is important to emphasize that we would still expect the impact of CREC on total economic output in Rhode Island to be well over $1 billion from 2018-2036.

III. RESPONSES TO CREC ADVISORY OPINIONS

Q. HAVE YOU REVIEWED THE ADVISORY OPINIONS SUBMITTED BY THE OFFICE OF ENERGY RESOURCES, RHODE ISLAND DIVISION OF PLANNING AND PUBLIC UTLITIES COMMISSION?

A. Yes, I have reviewed the Advisory Opinions submitted by the OER, Division of Planning, and PUC that were submitted to the Board in the Fall of 2016. I have not yet reviewed any updated Advisory Opinions.

Q. DO YOU HAVE AN OPINION REGARDING THE OFFICE OF ENERGY RESOURCES' ADVISORY OPINION?

A. Yes. The OER's three major findings in its Advisory Opinion are consistent with my analysis and findings in Invenergy's Application before the EFSB, my April 2016 Pre-Filed Direct Testimony before the PUC, my July 2016 Pre-Filed Rebuttal Testimony before the PUC and this Pre-Filed Direct Testimony. The three major OER findings are (Pages 34-35):

- "*The Facility [CREC] will contribute to reducing CO_2 emissions associated with electricity used in Rhode Island .... In the long term, over the life of the Project, CREC will not cause CO_2 emissions across the region to increase*."
- "*Development and operation of the Project [CREC] is consistent with State energy policies, and will not hinder Rhode Island from meeting its GHG [greenhouse gas] reduction targets under the Resilient Rhode Island Act*."
- "*Development and operation of the Project [CREC] will not be detrimental to implementing Rhode Island's policies and statutory initiatives to increase energy efficiency and the expansion of renewable sources of electricity*."

In addition, OER found with regard to the state achieving the emissions standards outlined in the Resilient Rhode Island Act that *"[b]y lowering the system average CO_2 emission rate, the Project will contribute to lowering the consumption-based annual CO_2 emissions for Rhode Island within the electric generation sector*" (Page 19) and that *"[t]his [consumption-based] approach is consistent with a unanimous endorsement by the EC4 [the Rhode Island Executive Climate Change Coordinating Council] on May 11, 2016 to adopt a consumption-based methodology for measuring GHG in the electric sector*" (Page 9).

Q. DO YOU HAVE AN OPINION REGARDING THE RHODE ISLAND DIVISION OF PLANNING ADVISORY OPINION?

A. Yes. The Division of Planning's major findings in its Advisory Opinion that address the areas of focus for my testimony are also consistent with my analysis and findings in Invenergy's Application before the EFSB, my June 2016 Pre-Filed Direct Testimony before the PUC, my July 2016 Pre-Filed Rebuttal Testimony before the PUC and this Pre-Filed Direct Testimony. Planning's major findings in the area of my testimony are that CREC (Page 46):

- "*will reduce regional wholesale capacity and energy prices and that the Project [CREC] will lower electricity costs for Rhode Island consumers*;"
- "*will have a positive impact on the state's businesses*;"
- "*will result in positive revenue benefits to the State*;" and
- "*will have a positive impact on the Town of Burrillville's municipal revenue*."

Q. DO YOU HAVE AN OPINION REGARDING THE PUBLIC UTILITIES COMMISSION OPINION?

A. Yes. The PUC's three major findings in its Advisory Opinion are consistent with my analysis and findings in Invenergy's Application before the EFSB, my June 2016 Pre-Filed Direct Testimony before the PUC, my July 2016 Pre-Filed Rebuttal Testimony before the PUC and this Pre-Filed Direct Testimony. The three major PUC findings are (Page 22):

- "*the entire CREC facility is needed in order to meet the electric generation reliability needs of Southeastern New England and Rhode Island consumers*."
- "*the facility will provide meaningful savings in the capacity market for a period up to four years, and generate savings to wholesale energy prices in New England for many years, the effects of which should benefit Rhode Island consumers*."
- "*energy efficiency, conservation opportunities, and renewable energy supply cannot, at this time, reliably meet the need for which the Invenergy plant will be built and that they therefore do not provide an appropriate alternative to CREC*."

Q. ARE THERE OTHER ASPECTS OF THE PUBLIC UTILITIES COMMISSION OPINION THAT FURTHER CONFIRM THE NEED FOR CREC?

A. Yes. The PUC highlighted a few of the key reasons why CREC is needed. At the most basic level, the PUC agrees (page 8) that "*because CREC Unit 1 cleared the Forward Capacity Auction 10 in accordance with the wholesale market rules and has a Capacity Supply Obligation,* *CREC Unit 1 is needed for system reliability*." However, the PUC further explained that the full CREC facility is needed for a variety of other reasons beyond obtaining a Capacity Supply Obligation. In particular, the PUC made a determination for the need for CREC based on that fact that:

- "*Clear River Energy Center is Needed in Light of Announced and At Risk Plant Retirements of Fossil Fuel Generating Units*" (Page 8). The PUC highlighted that ISO-NE has identified approximately 10 GW of capacity that have either recently retired or are at-risk for closing, and that due to this retirement risk "*the entire CREC facility is needed for continued reliability in the region*" (Page 10).
- "*CREC is Needed in Rhode Island – An Import Constrained Zone, Designated as SENE by ISO-NE*" (Page 11). The PUC identified that ISO-NE has determined Rhode Island to be an import constrained zone, and found that since Rhode Island will continue to need electric imports with the addition of CREC "*it can only benefit the region and the State of Rhode Island consumers to have CREC located within the SENE zone. Therefore, CREC is needed within the SENE zone*" (Page 12).
- "*Resources Acquired Above the Net Installed Capacity Requirement are Needed*" (Page 12). The PUC found that "*there is no assurance that any of the new resources [in the FCA] will be built*" nor that "*all of the existing resources will deliver*" (Page 14). The PUC found that if a resource clears the FCA it is needed for reliability and to provide the greatest economic benefit to the region.

Q. DO YOU AGREE WITH THE PUBLIC UTILITIES COMMISSION'S EXPANDED ASSESSMENT THAT THE FULL CREC FACILITY IS NEEDED?

A. Yes. I agree with the PUC that there is both a discrete reliability need for CREC due to achieving a Capacity Supply Obligation through the FCA, and a broader need for the fully CREC facility based on other factors within the region that include, but are not limited to, reliability risks associated with possible retirements, support required for renewable energy generation, Rhode Island's import constrained zone, and the possibility that new generation that has cleared the auction may not be built.

IV. RESPONSES TO TOWN OF BURRILLVILLE'S WITNESS GLENN WALKER

Q. HAVE YOU REVIEWED THE TESTIMONY OF THE TOWN OF BURRILLVILLE'S WITNESS GLENN WALKER?

A. Yes.

Q. DO YOU DISAGREE WITH HIS PRE-FILED DIRECT TESTIMONY?

A. Yes. My greatest concern with Mr. Walker's pre-filed direct testimony is his incorrect and unsubstantiated statement that "*In light of recent developments, the September 12, 2016 Advisory Opinion from the RI PUC on these issues has been proven to be inaccurate*." (Page 3)

As I describe in the previous section, the RI PUC's Advisory Opinion takes a multifaceted approach to determining the need for the CREC. None of the recent developments Mr. Walker purports to identify invalidates the RI PUC's findings on need for the entire facility, which are identified within the RI PUC's Advisory Opinion in the four subheadings within the "Need" section of the Advisory Opinion. The four findings of need by the RI PUC are that (i) CREC Unit 1 cleared an FCA and has a 7 year obligation to provide capacity to ISO-NE, (ii) that there is a significant amount of capacity at risk for retirement in ISO-NE, (iii) that Rhode Island is an import constrained zone as identified by ISO-NE, and (iv) that resources above the Net Installed Capacity Requirement are needed.

The only one of these four topics that Mr. Walker addresses is the amount of capacity at risk for retirement, and this critique is due to Mr. Walker's gross misinterpretation of ISO-NE's 2015 Regional Energy Outlook and not due to any new information invalidating the PUC's Advisory Opinion. I describe Mr. Walker's misinterpretation in the answer to my next question.

Q. DO YOU AGREE WITH MR. WALKER'S ASSESSMENT OF POTENTIAL RETIREMENTS?

A. No. I disagree with Mr. Walker's choice to rely on the 2015 ISO-NE Regional Energy Outlook for a view on capacity that is at risk for retirement, which was two years out of date when he filed his testimony on March 2, 2017. This is in contrast to the 2017 ISO-NE Regional Energy Outlook, which was publically available and directly referenced on Page 10 of his testimony. Apart from other shortcomings discussed below, this alone results in an unrealistic and distorted assessment.

Nevertheless, it appears that Mr. Walker has misinterpreted the 2015 Regional Energy Outlook. Mr. Walker claims that in the 2015 Regional Energy Outlook "*most of the units at risk for retirement appear to have retired prior to FCA 11*" (Walker Page 7). This is simply not true. None of the 6,000 MW identified by ISO-NE as at risk for retirement in the 2015 Regional Energy Outlook have retired to date. On Page 22 of the 2015 Regional Energy Outlook, ISO-NE outlines that there is 3,500 MW of capacity slated to retire by 2018, and an additional 6,000 MW of capacity at risk of retiring by 2020. In other words, 9,500 MW in total. This is fully consistent with the RI PUC's finding that CREC is needed to address the substantial amount of capacity that is at risk for retirement.

Q. ARE THERE ANY KEY DIFFERENCES BETWEEN THE 2017 ISO-NE REGIONAL ENERGY OUTLOOK AND THE 2015 ISO-NE REGIONAL ENERGY OUTLOOK?

A. Yes, and this is further reason to question Mr. Walker's use of the 2015 document. The 2017 ISO-NE Regional Energy Outlook identified additional capacity that is slated for retirement that was not even identified as at risk in the 2015 ISO-NE Regional Energy Outlook. In particular, the 2017 ISO-NE Regional Energy Outlook identifies the pending retirement of the 683 MW Pilgrim Nuclear Power Station in 2019, which was not included in the 2015 Regional Energy

Outlook as capacity at risk for retirement by 2020. This highlights the fact that facilities that are not identified as at risk by ISO-NE may still retire, which increases the importance of new capacity entry.

Q. DOES THE 2017 ISO-NE REGIONAL ENERGY OUTLOOK PROVIDE ANY ADDITIONAL NOTABLE COMMENTARY ON RETIREMENTS?

A. Yes. The 2017 ISO-NE Regional Energy Outlook states that, beyond the capacity identified as at risk for retirement, "*uncertainty surrounds the future of…the region's remaining nuclear plants*" (2017 Regional Energy Outlook Page 27[16]). The remaining nuclear capacity (excluding Pilgrim) is nearly 3,300 MW of additional capacity that may be facing economic pressure to continue operations. This includes the 2,088 MW Millstone nuclear power plant which Dominion has indicated it is now assessing for retirement after the Connecticut legislature failed to pass legislation to subsidize the facility in connection with its purported zero emissions benefits.

Q. WAS THE 2017 ISO-NE REGIONAL ENERGY OUTLOOK PUBLISHED BEFORE OR AFTER FCA 11?

A. The 2017 ISO-NE Regional Energy Outlook was published after FCA 11, indicating that ISO-NE still views this capacity as at risk for retirement.

Q. DO YOU DISAGREE WITH OTHER ASPECTS OF MR. WALKER'S TESTIMONY?

A. Yes. In particular, I am concerned that Mr. Walker makes several unsupported statements based on the results of FCA 11 without conducting any quantitative analysis to justify his position beyond that timeframe. However, these unsupported claims by Mr. Walker do not impact the RI PUC's determination of need in its Advisory Opinion.

Examples of Mr. Walker's unsupported (and incorrect) statements include, but are not limited to, the following: (1) he claims that CREC Unit 2 will not clear in the next several auctions,

[16] Attached as E**xhibit RH-4**.

but fails to conduct any analysis of the future supply and demand in the market; (2) he makes statements about future of renewable generation and energy efficiency growth without any analysis behind the cost-effectiveness of these technologies or what the growth trajectory of these technologies will look like; and (3) he states that capacity above the NICR is not needed, despite the fact that ISO-NE and the RI PUC have both determined that capacity above the NICR is needed.

V. RESPONSES TO TESTIMONY FILED ON BEHALF OF THE CONSERVATION LAW FOUNDATION

Q. HAVE YOU REVIEWED THE TESTIMONY OF CLF WITNESS PROFESSOR ROBERTS?

A. Yes.

Q. DO YOU DISAGREE WITH HIS PRE-FILED TESTIMONY?

A. Yes. My two greatest concerns with Professor Roberts' pre-filed direct testimony is that he (1) fails to analyze CREC's emissions impact on a regional basis, and (2) that he incorrectly believes the Resilient Rhode Island Act should be implemented on a generation-based accounting methodology. On page 21 of his testimony, he states that he "*performed no analysis on the overall effect on carbon emissions for the seven state area* ...." In contrast, I conducted the regional analysis, as I described in my Pre-Filed PUC Direct Testimony. This regional approach is consistent with the regional goals that are set forth in the RGGI, as well as the Resilient Rhode Island Act. The regional approach is also consistent with the regional nature of the electric generation market managed by ISO-NE. As stated herein, my updated analysis continues to show that CREC is consistent with the regional goals set forth in both RGGI and the Resilient Rhode Island Act by lowering total regional emissions, with the region defined as ISO-NE and NYISO. Moreover, as I describe in more detail below, the Rhode Island Executive Climate Change Coordinated Council ("EC4"), indicated that a consumption-based methodology (versus generation-based methodology) for accounting for CO_2 is most appropriate for Rhode Island. The EC4 is the governing council created by the Resilient Rhode Island Act charged with developing an emission reduction plan under the Act.

Q. WHY IS IT INCORRECT TO ANALYZE CREC'S EMISSIONS WITHOUT LOOKING AT THE REGIONAL IMPACT?

A. A significant component of CO_2 emissions triggered by Rhode Island electric demand would be missed by stopping an analysis at the state's border, given that Rhode Island's electricity load is served by power imported from other portions of ISO-NE (much of which is carbon emitting fossil-fueled power). Within a CO_2 accounting context, such a point of view would result in emissions "leakage"—not properly accounting for the impacts of emissions "outside" of a specified area even though emissions in the region "outside" of the specified area are impacted by activities "inside" the specified area.

If one were to take such a "Rhode Island-only" point of view to its logical (and extremely unrealistic) conclusion, analyzing Rhode Island as an electrical and emissions island thereby necessitates a world view that Rhode Island, in the future, will generate all of its energy needs within the state. It does not require in depth analysis to recognize that, in this near-sighted world view, Rhode Island's CO2 emissions and ratepayer costs would almost certainly go up, given the need for more baseload and quick-start generation to be constructed in the state (even if a portion of those in-state needs were eventually met with renewable generation, given the need to balance the intermittency of this generation).

Q. DOES THE CONSTRUCTION AND OPERATION OF CREC RUN COUNTER TO OBJECTIVES LAID OUT IN THE RESILIENT RHODE ISLAND ACT, AS SOME OBJECTORS TO THE PROJECT CLAIM?

A. Absolutely not. The Resilient Rhode Island Act was enacted to help reduce overall *global* emissions regarding the *global* issue of climate change. In particular, as described in Professor

Roberts' pre-filed testimony before the EFSB, on Page 10 Line 18, the carbon-emission-reduction goals in the Resilient Rhode Island Act are based on an overarching goal to see the "*reduction of **worldwide carbon emissions** by 80% below 1990 levels by 2050* [emphasis added]." This is the target set by the Resilient Rhode Island Act at R.I. Gen. Laws § 42-6-2.2.

Moreover, the Resilient Rhode Island Act states that, among the goals of the Rhode Island Executive Climate Change Coordinating Council is to "*work with other New England states to explore areas of mutual interest to achieve common goals*" (R.I. Gen. Laws § 42-6-2.2(a)(8)). The common goal here is regional CO_2 reduction, in support of the overarching goal of **worldwide carbon emissions** reductions, and CREC advances that objective as noted in my prior responses with regard to the RGGI program.

Q. IS YOUR ASSESSMENT STILL THE SAME NOW THAT THE EC4 HAS ISSUED ITS STRATEGIC PLANNING DOCUMENT IN LATE 2016?

A. Yes, my assessment is the same. The December 2016 Rhode Island Greenhouse Gas Emissions Reduction Plan[17], published by EC4, indicated that a consumption-based methodology is most appropriate. This plan, which outlines strategies to meet the targets for greenhouse gas emission reductions under the Resilient Rhode Island Act states "*The EC4 formally adopted the use of a consumption-based emission accounting because this method more realistically comports with the regional nature of New England's electric grid and is consistent with the approaches taken by neighboring states. It can also be a more informative metric for state-level policymaking because many policy instruments available to states have more influence on electricity consumption than electricity generation*" (2016 Rhode Island Greenhouse Gas Emissions Reduction Plan Page 7).

[17] Available at http://www.planning.ri.gov/documents/climate/EC4%20GHG%20Emissions%20Reduction%20Plan%20Final%20Draft%202016%2012%2029%20clean.pdf.

Q. DOES ISO-NE PROVIDE ANY ADDITIONAL INSIGHT REGARDING WHETHER A CONSUMPTION-BASED OR GENERATION-BASED ACCOUNT APPROACH IS MOST RELEVANT?

A. Yes. On February 20, 2017, ISO-NE submitted comments to the Massachusetts Department of Environmental Protection's ("MA DEP") on Massachusetts' proposed rule change from a consumption-based approach to a generation-based approach under the Massachusetts' Global Warming Solutions Act. Moving from a consumption-based approach to a generation-based will require that electricity produced in Massachusetts to be shifted to other states. ISO-NE found (Page 1) that while improving carbon emissions within Massachusetts, such a policy could "*increase regional emissions and raise wholesale electricity costs….because electricity production is shifted from Massachusetts to less efficient plants and likely higher emitting fuel sources in the region*."[18] Such an approach is antithetical to the goal of reducing overall carbon emissions.

VI. <u>RESPONSE TO CONSERVATION LAW FOUNDATION'S RESPONSES TO THE TOWN OF BURRILLILLE'S 1st SET OF DATA REQUESTS</u>

Q. IN RESPONSE NO. 1-1, SECTION A, CLF QUOTES YOUR APRIL 22, 2016 PRE-FILED PUC TESTIMONY, PAGE 16, AND STATES THAT YOUR CARBON EMISSIONS "ANALYSIS IS SERIOUSLY FLAWED FOR SEVERAL REASONS." DO YOU AGREE WITH THAT STATEMENT?

A. I do not. All three of CLF's criticisms are severely flawed or misleading.

Q. CAN YOU PLEASE EXPLAIN WHY CLF'S FIRST STATEMENT IS FLAWED?

A. CLF claimed that my analysis only shows a reduction in emissions for the first three years of operation and implied that these reductions would not occur in the future.

My previous analysis that CLF criticized addressed a four year timeframe (2019-2022), and it shows that the addition of CREC will lead to an annual average emission reductions

[18] Attached as **Exhibit RH-5**.

reduction within the New England and New York region of 1.01% for CO_2, 3.12% for NOx and 3.35% for SO_2. After this time period, as I describe in the next question, CREC will continue to displace older, less efficient and dirtier resources well beyond 2022.

Q. WHY IN YOUR PREVIOUS TESTIMONY DID YOU ONLY REPORT VALUES FROM 2019 THROUGH 2022 (AND FROM 2020 THROUGH 2024 IN YOUR CURRENT TESTIMONY), IF YOU WOULD EXPECT EMISSIONS REDUCTIONS OVER A LONGER TIMEFRAME?

A. My emissions analysis relied on the same modeling that I conducted for my ratepayer savings analysis, which primarily focused on the first 4 years of CREC's operations (2019-2022). To be consistent, I used the same time period for emissions reductions. However, I would expect continued emissions and ratepayer energy costs savings over a much longer timeframe.

I note that Seth Parker of Levitan and Associates, the expert witness for DPUC and OER, agreed that conducting this analysis over the first four years of the facility's operations (from 2019 through 2022) was a reasonable approach (Page 32). He also agreed with my assessment over the longer term stating, "*I would expect that CREC will displace higher cost and less efficient generation resources for many years due to its high efficiency relative to other power plants in the ISO-NE system*"[19]. Additionally, the OER's Advisory Opinion dated September 9, 2016 also agrees with this assessment, stating "*We expect that beyond the reported forecast period (post-2025), the Project will continue to displace less efficient and higher-emitting resources*" (Page 20).

In my updated analysis, primarily because the CREC online dates have been delayed to June 2020 for CREC 1 and June 2021 for CREC 2, I have extended the tenor of my analysis to 5 years (2020 through 2024).

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[19] *See* PUC testimony of Seth Parker in PUC Docket No. 4609, at pg 36.

Q. DOES YOUR UPDATED ANALYSIS CONTINUE TO SHOW MATERIAL EMISSIONS SAVINGS?

A. Yes. My updated analysis continues to show material emissions savings. The updated analysis address a five year timeframe (2020-2024), and it shows that the addition of CREC will lead to an annual average emission reductions reduction of 0.95% for CO_2, 0.99% for NOx and 2.88% for SO_2 for the New England and New York region. Moreover, similar to my previous analysis, I would expect CREC to continue to displace older, less efficient and dirtier resources beyond 2024.

Q. CAN YOU PLEASE EXPLAIN WHY CLF'S SECOND STATEMENT IS FLAWED?

A. CLF claimed that since CREC's emission rate is above the 2015 ISO-NE average emission rate, it is not possible for CREC to reduce overall emissions. This statement by CLF demonstrates a poor understanding of power market operations. It is not as simple as calculating a straight average emissions rate across all New England generators (with and without CREC's emissions rate) to evaluate emissions impacts. The key factor that CLF ignores is that CREC will displace higher emitting resources when it comes online. This analysis can only be conducted by actually forecasting the operations with and without CREC. This is something that I have done, as described in the updated confidential spreadsheet analysis that was filed in Invenergy's Supplemental Response to the Division of Planning's March Data Request, filed with the Board on June 23, 2017.

My methodology relies on a robust, industry standard dispatch simulation model, which I used to assess the impacts of CREC. DPUC expert witness Seth Parker agreed in his Pre-Filed Direct PUC Testimony that my model is "*reliable*" and that he is "*satisfied that the key assumptions*" in my analysis "*are reasonable*" (Page 38). Note that my updated analysis in this Pre-Filed testimony uses the same modeling methodology and incorporates updated market assumptions. Moreover, the OER Advisory Opinion agreed stating that my "*model supports a reasonable forecast of the Project's impact on CO_2 emissions in the region*" (Page 34). In other words, using a chronological dispatch simulation model will accurately assess the fact that a highly efficient natural gas combined cycle facility would displace higher emitting resources, thus lowering overall emissions.

In contrast, CLF merely compared two numbers: CREC's CO_2 emissions rate of 760 lb/MMBtu with the 2014 ISO-NE annual system average of 724 lb/MMBtu published in ISO-NE's 2014 ISO New England Air Emissions Report. Trying to compare these numbers to imply that CREC will increase the system average demonstrates a fundamental lack of understanding of the ISO-NE power market. CREC will likely be the most efficient natural gas power generation unit in New England when the facility comes online. Since the facility has a lower emissions rate than much higher polluting resources, displacing higher polluting resources will reduce the overall system emissions average.

Q. CAN YOU PLEASE EXPLAIN WHY CLF'S THIRD STATEMENT IS FLAWED?

A. CLF implies that CREC will be detrimental to both Rhode Island and U.S. environmental goals. I have already discussed how CREC will benefit regional environmental goals by reducing overall emissions and CREC will also enhance Rhode Island's ability to meet the Resilient Rhode Island Act. CLF came to their flawed conclusion by relying on an inappropriate methodology to account for GHG emissions.

Q. CAN YOU EXPLAIN WHAT IS THE GHG EMISSIONS ACCOUNTING METHODOLOGY?

A. Yes. Again, as with my criticism of Professor Roberts's testimony, this comes down to discussion of Generation-Based Accounting and Consumption-Based Accounting of CO_2 emissions. Generation-Based Accounting measures GHG emissions based on emissions produced within a state, which I believe is a flawed approach. In contrast, Consumption-Based Accounting measures GHG emissions based on electricity used within a state. Since ISO-NE operates as a regional electricity grid that shares electricity on a system-wide basis, these two values are typically not the same. For example, if a Rhode Island entity signs a renewable contract with an out-of-state renewable generator for use within Rhode Island that generation would not count as a GHG reduction using Generation-Based Accounting (since it is located out-of-state), whereas it would count as a GHG reduction using Consumption-Based Accounting.

As stated in the OER's Advisory Opinion, a Consumption-Based Accounting approach is most appropriate for GHG emissions accounting under the Resilient Rhode Island Act. Among the OER's rationale (Page 9), a Consumption-Based Accounting approach is most appropriate due to the regional nature of the ISO-NE power grid, the fact that Rhode Island does not control dispatch decisions within ISO-NE, the fact that some renewable resource contracts with Rhode Island utilities are located out-of-state, and the fact that the approach is consistent with the design of RGGI.

Q. USING THE CONSUMPTION-BASED ACCOUNTING APPROACH, CAN YOU STATE THAT CO2 EMISSIONS IN RHODE ISLAND WILL DECREASE DUE TO CREC?

A. Yes. Using Consumption-Based Accounting, resources such as CREC that lower the carbon intensity of the overall ISO-NE system will reduce the carbon intensity of energy consumed by Rhode Island customers. This will help Rhode Island meet its goals under the Resilient Rhode Island Act. As stated in the OER Advisory Opinion, the "*project is consistent with State energy policies, and will not hinder Rhode Island from meeting its GHG reduction targets under the Resilient Rhode Island Act*" (Page 35).

Q. IN RESPONSE NO. 1-1, SECTION B, CLF ADMITS THAT CREC WILL CAUSE SHORT-TERM RATEPAYER BENEFITS, BUT STATES THAT "THERE

WOULD ALSO BE LARGE AND CERTAIN RATEPAYER HARMS." DO YOU AGREE WITH THAT STATEMENT?

A. No, I do not agree. CLF provides no analysis to support its claim that there would be "*large and certain ratepayer harms*," nor does CLF quantify or otherwise demonstrate what these harms actually are for the ratepayer. In fact, as outlined in the PUC Advisory Opinion, to the extent CREC was not needed in the market, "*all of the costs and risks relative to the plant [CREC] would be borne by the Applicant [Invenergy], and not by the ratepayers*" (Pages 2-3).

Q. IN RESPONSE NO. 1-2, CLF CLAIMS THAT SUBSIDIES AND THE SOCIAL COST OF CARBON SHOW THAT RENEWABLES ARE MORE "COST EFFICIENT" TO CONSUMERS THAN CREC. DO YOU AGREE WITH THAT STATEMENT?

A. No, I do not. CLF does not provide any quantitative evidence to support its assertion nor does CLF identify any specific project that is a direct alternative to CREC.

ISO-NE's FCA determines the most optimal economic solution in terms of the composition of resources to meet reliability. Similar to CREC, renewable resources are able to participate in the FCA. Typically, new resources that bid into the auction are subject to the Minimum Price Offer Rule ("MOPR") that governs the lowest price that a new resource is able to bid into the market. However, renewable resources currently have the added benefit that the first 200 MW bid into the FCA each year are exempt from this rule. As discussed by DPUC witness Seth Parker in his pre-filed testimony before the PUC, this exemption allows new renewable resources to be "*virtually guaranteed to c1ear, with or without CREC*" (Page 46) However, only 73 MW of new solar and wind resources cleared in FCA 10, which is 127 MW below the 200 MW MOPR exemption threshold. Similarly, in FCA 11, only 11 MW of new solar and wind resources cleared, which is 189 MW below the 200 MW MOPR exemption threshold. This demonstrates that there is a lack of cost effective alternatives to CREC currently available to the market.

VII. <u>CONCLUSIONS</u>

Q. DO YOU HAVE AN OPINION, TO A REASONABLE DEGREE OF SCIENTIFIC CERTAINTY, WHETHER CREC IS NEEDED TO MEET THE ENERGY NEEDS OF THE STATE AND/OR REGION?

A. Yes. Per my analysis, CREC is needed to meet the energy needs of both Rhode Island and the broader New England region.

Q. DO YOU HAVE AN OPINION, TO A REASONABLE DEGREE OF SCIENTIFIC CERTAINTY, WHETHER CREC IS COST-JUSTIFIED AND CAN BE EXPECTED TO PRODUCE ENERGY AT THE LOWEST REASONABLE COST TO THE CONSUMER?

A. Yes. Per my analysis, the expected rate payer savings, the fact that CREC will not involve rate payer funding and the fact CREC cleared FCA 10, CREC is cost justified and can be expected to produce energy at the lowest reasonable cost to the consumer. Upon commercial operation, CREC will be one of the most—if not the most—efficient, low-cost and cleanest natural gas power generation facility in New England.

Q. DO YOU HAVE AN OPINION, TO A REASONABLE DEGREE OF SCIENTIFIC CERTAINTY, WHETHER CREC WILL ENHANCE THE SOCIOECONOMIC FABRIC OF THE STATE?

A. Yes. As my analysis indicates, CREC will create hundreds of new jobs through both the construction and operation of the facility.

Q. DO YOU HAVE AN OPINION, TO A REASONABLE DEGREE OF SCIENTIFIC CERTAINTY, WHETHER CREC WILL ALLOW THE STATE TO MEET ITS EMISSIONS OBJECTIVES UNDER THE RESILIENT RHODE ISLAND ACT AND RGGI?

A. Yes. As my analysis indicates, CREC will allow the State to meet its Resilient Rhode Island Act and RGGI emissions targets utilizing the recommended Consumption-Based Approach and can help the State facilitate the introduction of incremental renewable resources on the grid (furthering the ability of the State to meet emissions objectives).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT RH-1

MAY 1, 2017

ISO new england

CELT Report

2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission

System Planning

Introduction

2017 ISO New England (ISO-NE) Reliability Coordinator Area Forecast[(1)]

The "2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission" (CELT Report) is a source of assumptions for use in electric planning and operations reliability studies. This report provides assumptions for the ISO New England Reliability Coordinator area.

In Section 1, the ISO New England Reliability Coordinator area reference load forecast may be characterized as having a fifty percent chance of being exceeded. The load forecast distributions for the years 2017 through 2026 are included in Section 1.6 of this report. Additional information on the load forecast, including the forecast bandwidths, is available on the ISO New England web site (see links below).

The capacity values in Section 1 are based on the Capacity Supply Obligations (CSO) for the Forward Capacity Market's (FCM) 2016-2017, 2017-2018, 2018-2019, 2019-2020 and 2020-2021 Capacity Commitment Periods as of March 18, 2017. These include new and existing generating resources, demand resources, and imports.

The CSOs for each of the commitment periods are based on the following FCM auction results:

2016-2017	Annual Reconfiguration Auction 3
2017-2018	Annual Reconfiguration Auction 3
2018-2019	Annual Reconfiguration Auction 1
2019-2020	Forward Capacity Auction
2020-2021	Forward Capacity Auction

The generating resource and demand resource CSO totals for the 2020-2021 Capacity Commitment Period are assumed to remain in place for the remainder of the CELT reporting period. Imports beyond the 2020-2021 Capacity Commitment Period reflect only known, long-term contracts.

The annual generating capacity totals based on Seasonal Claimed Capability (SCC)[2] are included as a line item in Sections 1.1 and 1.2. Those values are based on the SCCs of existing assets plus the expected capability of future FCM and non-FCM resources. The non-FCM resources are those that do not have FCM obligations, but are part of the ISO New England Generator Interconnection Queue[3] and are expected to become commercial in 2017 or 2018.

Section 2.1 of the CELT Report lists details for all generating assets in-service as of April 1, 2017. It also includes SCC values for generating assets as of January 1, 2017 and the winter 2016/17 peak, which occurred on December 15, 2016, as well as projected summer SCC values for July 1, 2017.

Section 3.1 consists of total state-by-state solar PV forecasts based on nameplate rating, as well as the estimated summer seasonal peak load reductions and estimated energy production from behind-the-meter (BTM) PV. The forecast methodology and assumptions are available at http://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast.

Introduction

Section 4 summarizes data from the Forward Capacity Market. Section 4.1 summarizes the results of the 2016-2017, 2017-2018, 2018-2019, 2019-2020, and 2020-2021 Forward Capacity Market Capacity Supply Obligations (CSOs) by Load Zone as of March 18, 2017. In the case of 2016-2017, monthly auction results are not taken into consideration; the results shown are for the third Annual Reconfiguration Auction (ARA3). Section 4.2 contains the Renewable Technology Resource (RTR) Allotments. Section 4.3 lists the Qualified and Cleared Capacity for all Resources that qualified to participate in the eleventh Forward Capacity Auction (FCA 11).

The October 31, 2008 Forward Capacity Market (FCM)/Queue Amendments filing (FERC Docket ER09237 http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2008/oct/er09_237_000_10_8_31_fcm_queue.pdf) established the Network Resource Capability (NRC) and Capacity Network Resource Capability (CNRC) values for each generating resource. Section 5.1 lists the NRC & CNRC values calculated consistent with Schedules 22 and 23 of the Open Access Transmission Tariff (the Large and Small Generator Interconnection Procedures).

Section 6.1 lists links associated with transmission related documents available on the ISO New England website at: http://www.iso-ne.com.

The appendices in the report are as follows:

- Appendix A defines the commonly used terms and abbreviations used in this report;
- Appendix B provides a list of the Federal Information Processing Standard (FIPS) Codes and the list of Regional System Plan (RSP) Subareas;
- Appendix C is the most recent update of the New England geographic transmission map.

CELT Reports and related documents are available on the ISO New England website at:

http://www.iso-ne.com/system-planning/system-plans-studies/celt
http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seasonal-claimed-capability
http://www.iso-ne.com/system-planning/system-plans-studies/rsp
http://www.iso-ne.com/participate/applications-status-changes/new-modified-interconnections
http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue

Please do not hesitate to contact ISO New England at custserv@iso-ne.com with any questions or comments regarding the information contained herein.

FOOTNOTES:

(1) ISO New England is the Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP) for New England. Throughout this document, the ISO is referred to as the RC since the RC has responsibility for overseeing the other two functions.

(2) For more information on generating assets, refer to the Seasonal Claimed Capability Report at: http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seasonal-claimed-capability.

(3) The Generator Interconnection Queue is posted on the ISO New England website at http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

Preface

This 2017 edition of the "Forecast Report of Capacity, Energy, Loads, and Transmission" (CELT) reflects a load forecast based upon demographic, economic, and market information available through winter 2016-17 for publication in May 2017. Accordingly, this CELT edition supersedes prior CELT publications.

This report presents the ISO-NE Reliability Coordinator area 2017-2026 forecast of:

- Electric energy demand and peak load;
- Existing ISO-NE Control Area electrical capacity and proposed changes;
- Scheduled and proposed transmission changes; with listings and summaries of existing and proposed generation projects

Generating asset details are represented in Section 2.1 of this report for three different periods: a snapshot of January 1, 2017, a snapshot of the winter peak on December 15, 2016, and a projection for the summer of 2017.

This report represents the efforts of Market Participants' staffs, jointly with ISO-NE, under the review of the Load Forecasting and Reliability Committees.

Additional information regarding the documentation of the electric energy demand and peak load forecasts presented in this report may be found on ISO-NE's web site at:

http://www.iso-ne.com/system-planning/system-plans-studies/celt

Table of Contents

1.1 Summer Peak Capabilities and Load Forecast (MW)

ISO-NE RELIABILITY COORDINATOR AREA	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1. LOAD (1, 2, 3)											
1.1 REFERENCE - Without reductions	28815	29146	29454	29753	30039	30327	30623	30923	31223	31521	31820
1.1.1 Behind-the-Meter (BTM) PV (4)	439	575	690	783	848	891	929	963	992	1014	1035
1.2 REFERENCE - With reduction for BTM PV	28376	28571	28764	28970	29191	29436	29694	29960	30231	30507	30785
1.2.1 Passive DR (PDR) used in System Planning (5)	1839	2089	2306	2561	2893	3223	3527	3805	4055	4278	4475
1.3 REFERENCE - With reduction for BTM PV and PDR	26537	26482	26458	26409	26298	26213	26167	26155	26176	26228	26310
2. CAPACITY BASED ON FCM OBLIGATIONS											
2.1 GENERATING RESOURCES (6)	29888	29627	30607	31326	31359	31359	31359	31359	31359	31359	31359
2.2 DEMAND RESOURCES (6, 7)	2441	2691	2696	2734	3211	3211	3211	3211	3211	3211	3211
2.2.1 ACTIVE DR	556	382	546	367	420	420	420	420	420	420	420
2.2.2 PASSIVE DR	1885	2309	2150	2367	2791	2791	2791	2791	2791	2791	2791
2.3 IMPORTS (8)	1162	1376	1479	1480	1265	89	89	89	89	89	89
2.4 TOTAL (9)	**33492**	**33693**	**34782**	**35540**	**35835**	**34659**	**34659**	**34659**	**34659**	**34659**	**34659**
3. CAPACITY BASED ON SEASONAL CLAIMED CAPABILITY (SCC) (10, 11)											
3.1 GENERATION CLAIMED FOR CAPABILITY	30581	29174	30933	31621	31712	31730	31747	31762	31773	31779	31784
4. RESERVES - Based on Reference Load with reduction for Passive DR											
4.1 INSTALLED RESERVES - Based on CSOs of Generating Resources (line 2.1), Active DR (line 2.2.1), and Imports (line 2.3)											
4.1.1 MW	5070	4903	6175	6763	6746	5656	5702	5713	5692	5640	5559
4.1.2 % OF LOAD	19	19	23	26	26	22	22	22	22	22	21
4.2 INSTALLED RESERVES - Based on Generation SCC (line 3.1), Active DR (line 2.2.1), Imports (line 2.3), and Exports (see footnote 12)											
4.2.1 MW	5663	4350	6400	6959	7099	6027	6090	6116	6106	6060	5984
4.2.2 % OF LOAD	21	16	24	26	27	23	23	23	23	23	23

KEY:

4.1.1 = 2.1 + 2.2.1 + 2.3 – 1.3
4.1.2 = (4.1.1 / 1.3) x 100
4.2.1 = (3.1 + 2.2.1 + 2.3) – 1.3
4.2.2 = (4.2.1 / 1.3) x 100
2.4 = 2.1 + 2.2 + 2.3

FOOTNOTES:

See Section 1.1 Footnotes on following sheet

1.1 Footnotes

(1) Represents MW load level associated with a reference forecast having a 50% chance of being exceeded. More information on the April 2017 CELT forecast, including the high and low bandwidths, is available on the ISO-NE Website located at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

(2) Three versions of the seasonal peak load forecast are shown. The first forecast does not reflect the peak and energy savings of Passive Demand Resources (PDR) or Behind-the-Meter (BTM) PV. The second forecast shown reflects a reduction for BTM PV. The third forecast shown reflects the reductions of BTM PV and PDR. Detailed forecast documentation on the ISO-NE website includes all three versions of the forecast.

(3) The 2016 summer peak load shown reflects weather normalization. Prior to weather normalization, the actual metered 2016 summer peak of 25,596 MW occurred on August 12, 2016 at hour ending 15:00. See Section 1.5 for actual and estimated peaks and energies. The reconstituted peak was 28,504 MW, which includes reconstitution for the load reducing action of FCM Passive Demand Resources and estimated peak load reduction resulting from behind-the-meter PV at the time of the peak.

(4) Line 1.1.1 consists of Behind-the-Meter PV estimated summer peak load reductions as of July 1 of that year, including an 8% transmission and distribution loss gross up. Refer to Section 3.1 for more details on these values.

(5) The passive DR shown on line 1.2.1 consists of the Qualified Capacity (QC) of existing resources and primary auction (FCA) results for new resources. These values are used by ISO-NE System Planning in their long-term Needs Assessments and Solutions Studies (see Sec. 5.2 of this report for a breakdown by Load Zone and DR type), and are different from the Capacity Supply Obligations shown on line 2.2.2. Beginning in 2021-2022, passive DR includes an ISO-NE forecast of incremental EE beyond the FCM.

(6) The 2017 through 2020 capacity for generating and demand resources consists of the current Forward Capacity Market CSOs as of March 18, 2017, and the 2016 CSOs are based on the 2016-2017 ARA 3 results. The 2020 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 435 MW of Static and Dynamic De-List Bids that were cleared to leave the 2020-2021 Forward Capacity Auction will remain de-listed through the reporting period. The Citizens Block Load CSO is treated as an import rather than a generating resource.

(7) The demand resource values are based on DR with FCM CSOs, including an 8% transmission and distribution loss gross-up. A passive DR forecast is included with the QC-based DR values on line 1.2.1, beginning in 2021.

(8) The 2016 through 2020 imports are based on FCM import CSOs. An Administrative Export De-List of 100 MW is taken into account in the generation capability values from 2016 through 2019. That 100 MW export will remain as an Export De-List Bid in 2020. The imports beyond the 2020-2021 Capacity Commitment Period reflect only known, long-term contracts.

(9) May not equal sum due to rounding.

(10) The generating capability based on SCC values includes all existing ISO New England generating assets as well as projected additions and retirements. Future generating assets consist of non-FCM resources that are expected to go commercial in 2017 or 2018, and all new resources with FCM CSOs. The capabilities of the FCM resources are based on their Qualified Capacity. Also included is a forecast of non-FCM PV capacity, which is based on the nameplate PV forecast shown in Section 3.1.1, together with the assumed percentage of annual growth (37% in service by July 1), and estimated summer seasonal peak load reduction (in % of nameplate) for each year, as shown in Section 3.2.2.

(11) The 2017 SCC value of 29,174 MW is consistent with the total capacity projected for July 1 in the Section 2.1 Generator List.

(12) Exports consist of a 100 MW Export De-List through 2020.

1.2 Winter Peak Capabilities and Load Forecast (MW)

ISO-NE RELIABILITY COORDINATOR AREA	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
1. LOAD (1, 2, 3)											
1.1 REFERENCE - Without reductions	22992	23029	23180	23318	23436	23556	23691	23830	23970	24106	24244
1.1.1 Behind-the-Meter (BTM) PV (4)	0	0	0	0	0	0	0	0	0	0	0
1.2 REFERENCE - With reduction for BTM PV	22992	23029	23180	23318	23436	23556	23691	23830	23970	24106	24244
1.2.1 Passive DR (PDR) used in System Planning (5)	1652	1832	2171	2371	2788	3105	3398	3666	3907	4122	4312.056
1.3 REFERENCE - With reduction for BTM PV and PDR	21340	21197	21009	20947	20648	20451	20293	20164	20063	19984	19931.94
2. CAPACITY BASED ON FCM OBLIGATIONS											
2.1 GENERATING RESOURCES (6)	30178	29995	31322	31975	31633	31633	31633	31633	31633	31633	31633
2.2 DEMAND RESOURCES (6, 7)	2427	2703	2699	2738	3198	3198	3198	3198	3198	3198	3198
2.2.1 ACTIVE DR	543	388	549	371	414	414	414	414	414	414	414
2.2.2 PASSIVE DR	1884	2315	2150	2367	2783	2783	2783	2783	2783	2783	2783
2.3 IMPORTS (8)	1137	1332	1017	1069	1265	91	91	91	91	91	91
2.4 TOTAL (9)	**33742**	**34029**	**35038**	**35782**	**36096**	**34921**	**34921**	**34921**	**34921**	**34921**	**34921**
3. CAPACITY BASED ON SEASONAL CLAIMED CAPABILITY (SCC) (10)											
3.1 GENERATION CLAIMED FOR CAPABILITY	33045	32331	33418	34204	34323	34323	34323	34323	34323	34323	34323
4. RESERVES - Based on Reference Load with reduction for Passive DR											
4.1 INSTALLED RESERVES - Based on CSOs of Generating Resources (line 2.1), Active DR (line 2.2.1), and Imports (line 2.3)											
4.1.1 MW	10518	10518	11879	12468	12664	11687	11845	11974	12075	12154	12206
4.1.2 % OF LOAD	49	50	57	60	61	57	58	59	60	61	61
4.2 INSTALLED RESERVES - Based on Generation SCC (line 3.1), Active DR (line 2.2.1), Imports (line 2.3), and Exports (see footnote 11)											
4.2.1 MW	13285	12754	13875	14597	15354	14378	14536	14664	14766	14845	14897
4.2.2 % OF LOAD	62	60	66	70	74	70	72	73	74	74	75

KEY:

4.1.1 = 2.1 + 2.2.1 + 2.3 – 1.3
4.1.2 = (4.1.1 / 1.3) x 100
4.2.1 = (3.1 + 2.2.1 + 2.3) – 1.3
4.2.2 = (4.2.1 / 1.3) x 100
2.4 = 2.1 + 2.2 + 2.3

FOOTNOTES:

See Section 1.2 Footnotes on following sheet

1.2 Footnotes

(1) Represents MW load level associated with a reference forecast having a 50% chance of being exceeded. More information on the April 2017 CELT forecast, including the high and low bandwidths, is available on the ISO-NE Website located at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

(2) Two versions of the seasonal peak load forecast are shown. The first forecast does not reflect the peak and energy savings of the passive demand resources. The second forecast shown reflects a reduction for that passive DR. Detailed forecast documentation on the ISO-NE website includes both the original CELT forecast and the forecast minus passive demand resources.

(3) The 2016/17 winter peak load shown reflects weather normalization. Prior to weather normalization, the actual metered 2016/17 winter peak of 19,581 MW occurred on December 15, 2016 at hour ending 18:00. See Section 1.5 for actual and estimated peaks and energies. The reconstituted (for the load reducing action of FCM Passive Demand Resources) peak of 22,185 MW occurred on December 15, 2016 at hour ending 18:00.

(4) Behind-the-Meter PV is assumed to be zero during the winter peak.

(5) The passive DR shown on line 1.2.1 consists of the Qualified Capacity (QC) of existing resources and primary auction (FCA) results for new resources. These values are used by ISO-NE System Planning in their long-term Needs Assessments and Solutions Studies (see Sec. 5.2 of this report for a breakdown by Load Zone and DR type), and are different from the Capacity Supply Obligations shown on line 2.2.2. Beginning in 2021/22, passive DR includes an ISO-NE forecast of incremental EE beyond the FCM.

(6) The 2017/18 through 2020/21 capacity for generating and demand resources consists of the Forward Capacity Market CSOs current as of March 18, 2017, and the 2016/17 CSOs are based on the ARA 3 results. The 2020/21 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 435 MW of Static and Dynamic De-List Bids that were cleared to leave the 2020-2021 Forward Capacity Auction will remain de-listed through the reporting period. The Citizens Block Load CSO is treated as an import rather than a generating resource.

(7) The demand resource values are based on DR with FCM CSOs, including an 8% transmission and distribution loss gross-up. A passive DR forecast is included with the QC-based DR values on line 1.2.1, beginning in 2020/21.

(8) The 2016/17 through 2020/21 imports are based on FCM import CSOs. An Administrative Export De-List of 100 MW is taken into account in the generation capability values from 2016/17 through 2019/20. That 100 MW export will remain as an Export De-List Bid in 2020/21. The imports beyond the 2020/21 Capacity Commitment Period reflect only known, long-term contracts.

(9) May not equal sum due to rounding.

(10) The generating capability based on SCC values includes all existing ISO New England generating assets as well as projected additions and retirements. Future generating assets consist of non-FCM resources that are expected to go commercial in 2017 or 2018, and all new resources with FCM CSOs. The capabilities of the FCM resources are based on their Qualified Capacity.

(11) Exports consist of a 100 MW Export De-List through 2020/21.

1.3 - Summary Summer Capability by Fuel/Unit Type (MW) (1)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NUCLEAR STEAM	4010	4008	4024	3347	3344	3344	3344	3344	3344	3344	3344
HYDRO (DAILY CYCLE - PONDAGE)	338	340	339	340	340	340	340	340	340	340	340
HYDRO (DAILY CYCLE - RUN OF RIVER)	261	252	277	239	248	248	248	248	248	248	248
HYDRO (WEEKLY CYCLE)	868	876	875	872	867	867	867	867	867	867	867
HYDRO (PUMPED STORAGE)	1677	1682	1670	1665	1667	1667	1667	1667	1667	1667	1667
GAS COMBINED CYCLE	8283	8806	9554	10092	10202	10202	10202	10202	10202	10202	10202
GAS/OIL COMBINED CYCLE	3957	4333	4306	4275	4416	4416	4416	4416	4416	4416	4416
GAS COMBUSTION (GAS) TURBINE	219	227	517	1335	1335	1335	1335	1335	1335	1335	1335
GAS/OIL COMBUSTION (GAS) TURBINE	542	556	552	549	546	546	546	546	546	546	546
OIL COMBUSTION (GAS) TURBINE	1695	1692	1697	1710	1696	1696	1696	1696	1696	1696	1696
COAL STEAM	1947	927	922	917	917	917	917	917	917	917	917
GAS/OIL STEAM	2831	2485	2497	2490	2490	2490	2490	2490	2490	2490	2490
OIL STEAM	2128	2216	2198	2192	2041	2041	2041	2041	2041	2041	2041
GAS INTERNAL COMBUSTION	5	5	5	5	5	5	5	5	5	5	5
GAS/OIL INTERNAL COMBUSTION	9	9	9	9	9	9	9	9	9	9	9
OIL INTERNAL COMBUSTION	116	116	112	110	105	105	105	105	105	105	105
BIO/REFUSE	897	948	902	962	905	905	905	905	905	905	905
WIND TURBINE	79	122	116	135	137	137	137	137	137	137	137
GAS FUEL CELL	21	20	16	21	23	23	23	23	23	23	23
PHOTOVOLTAIC	5	5	20	62	66	66	66	66	66	66	66
SUBTOTAL ISO-NE RELIABILITY COORDINATOR AREA CAPACITY (2, 4)	**29888**	**29627**	**30607**	**31326**	**31359**	**31359**	**31359**	**31359**	**31359**	**31359**	**31359**
DEMAND RESOURCES (2)	2441	2691	2696	2734	3211	3211	3211	3211	3211	3211	3211
IMPORTS (3)	1162	1376	1479	1480	1265	89	89	89	89	89	89
TOTAL ISO-NE RELIABILITY COORDINATOR AREA CAPACITY (4)	**33492**	**33693**	**34782**	**35540**	**35835**	**34659**	**34659**	**34659**	**34659**	**34659**	**34659**

FOOTNOTES:

(1) Gas/oil units are not necessarily fully operable on both fuels.

(2) The 2016 through 2020 capacity values consist of the Forward Capacity Market CSOs current as of March 18, 2017. The 2020 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 435 MW of Static and Dynamic De-List Bids that were cleared to leave the 2020/21 Forward Capacity Auction will remain de-listed through the reporting period.

(3) Imports are from entities outside the ISO-NE Reliability Coordinator area boundary. The 2016 through 2020 imports are based on FCM import CSOs. An Export De-List of 100 MW is taken into account in the generation capability values through 2020. The imports beyond the 2019/20 Capacity Commitment Period reflect only known, long-term contracts.

(4) May not equal sum due to rounding.

1.4 - Summary Winter Capability by Fuel/Unit Type (MW) [1]

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
NUCLEAR STEAM	4010	4008	4024	3347	3344	3344	3344	3344	3344	3344	3344
HYDRO (DAILY CYCLE - PONDAGE)	339	341	340	340	340	340	340	340	340	340	340
HYDRO (DAILY CYCLE - RUN OF RIVER)	384	418	438	411	396	396	396	396	396	396	396
HYDRO (WEEKLY CYCLE)	860	875	873	854	867	867	867	867	867	867	867
HYDRO (PUMPED STORAGE)	1677	1660	1670	1655	1667	1667	1667	1667	1667	1667	1667
GAS COMBINED CYCLE	8285	8873	9971	10369	10220	10220	10220	10220	10220	10220	10220
GAS/OIL COMBINED CYCLE	3983	4335	4313	4360	4416	4416	4416	4416	4416	4416	4416
GAS COMBUSTION (GAS) TURBINE	221	234	523	1335	1335	1335	1335	1335	1335	1335	1335
GAS/OIL COMBUSTION (GAS) TURBINE	542	556	552	549	546	546	546	546	546	546	546
OIL COMBUSTION (GAS) TURBINE	1719	1714	1739	1770	1707	1707	1707	1707	1707	1707	1707
COAL STEAM	1947	927	922	917	917	917	917	917	917	917	917
GAS/OIL STEAM	2831	2485	2481	2479	2479	2479	2479	2479	2479	2479	2479
OIL STEAM	2128	2216	2198	2192	2041	2041	2041	2041	2041	2041	2041
GAS INTERNAL COMBUSTION	5	5	5	5	5	5	5	5	5	5	5
GAS/OIL INTERNAL COMBUSTION	9	9	9	9	9	9	9	9	9	9	9
OIL INTERNAL COMBUSTION	116	116	112	110	105	105	105	105	105	105	105
BIO/REFUSE	902	958	913	973	915	915	915	915	915	915	915
WIND TURBINE	200	246	224	280	301	301	301	301	301	301	301
GAS FUEL CELL	21	20	16	21	23	23	23	23	23	23	23
PHOTOVOLTAIC	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL ISO-NE RELIABILITY COORDINATOR AREA CAPACITY [2, 4]	**30178**	**29995**	**31322**	**31975**	**31633**	**31633**	**31633**	**31633**	**31633**	**31633**	**31633**
DEMAND RESOURCES [2]	2427	2703	2699	2738	3198	3198	3198	3198	3198	3198	3198
IMPORTS [3]	1137	1332	1017	1069	1265	91	91	91	91	91	91
TOTAL ISO-NE RELIABILITY COORDINATOR AREA CAPACITY [4]	**33742**	**34029**	**35038**	**35782**	**36096**	**34921**	**34921**	**34921**	**34921**	**34921**	**34921**

FOOTNOTES:

(1) Gas/oil units are not necessarily fully operable on both fuels.

(2) The 2016/17 through 2020/21 capacity values consist of the Forward Capacity Market CSOs as of March 18, 2017. The 2020/21 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 435 MW of Static and Dynamic De-List Bids that were cleared to leave the 2020/21 Forward Capacity Auction will remain de-listed through the reporting period.

(3) Imports are from entities outside the ISO-NE Reliability Coordinator Area boundary. The 2016/17 through 2020/21 imports are based on FCM import CSOs. An Export De-List of 100 MW is taken into account in the generation capability values through 2020/21. The imports beyond the 2020/21 Capacity Commitment Period reflect only known, long-term contracts.

(4) May not equal sum due to rounding.

1.5.1 - Actual and Forecasted Peak Loads [(1)]

2016 ACTUAL

MONTHLY PEAK LOAD - MW	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	21866	21963	19730	19139	21567	22611	27102	28504	25701	18488	19712	22185
Reduced for BTM PV [(2)]	21866	21955	19730	19133	21253	22133	26596	27787	25320	18488	19712	22185
Reduced for BTM PV and PDR	19451	19561	17341	16963	19029	19966	24416	25596	23142	16298	17517	19581

2017 FORECAST

MONTHLY PEAK LOAD - MW	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	22165 A	20753 A	20082 A	17884	20291	25360	29146	29146	23790	18570	20117	23029
Reduced for BTM PV [(2)]	22165 A	20753 A	20082 A	17884	19734	24795	28571	28559	23192	18570	20117	23029
Reduced for BTM PV and PDR	19570 A	18130 A	17453 A	15795	17645	22706	26482	26470	21103	16481	18028	21197

2018 FORECAST

MONTHLY PEAK LOAD - MW	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	23029	22167	21391	17995	20465	25625	29454	29454	24028	18655	20227	23180
Reduced for BTM PV [(2)]	23029	22167	21391	17995	19790	24943	28764	28754	23319	18655	20227	23180
Reduced for BTM PV and PDR	21197	20335	19559	15689	17484	22637	26458	26448	21013	16349	17921	21009

ANNUAL

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	CAGR [(3)] 2017 to 2026
SUMMER PEAK - MW												
Without reductions	28504 A	29146	29454	29753	30039	30327	30623	30923	31223	31521	31820	0.98
Reduced for BTM PV	27787 A	28571	28764	28970	29191	29436	29694	29960	30231	30507	30785	0.83
Reduced for BTM PV and PDR	25596 A	26482	26458	26409	26298	26213	26167	26155	26176	26228	26310	-0.07
WINTER PEAK - MW [(4)]												
Without reductions	22185 A	23029	23180	23318	23436	23556	23691	23830	23970	24106	24244	0.93
Reduced for BTM PV	22185 A	23029	23180	23318	23436	23556	23691	23830	23970	24106	24244	0.93
Reduced for BTM PV and PDR	19581 A	21197	21009	20947	20648	20451	20293	20164	20063	19984	19932	0.23

FOOTNOTES:

A = ACTUAL

(1) Recognizing that the seasonal peaks usually occur within a few months of the year, the forecasted monthly peaks of July and August have been replaced by the summer peak, and December and January have been replaced by the winter peak.

(2) Actual BTM PV output is typically zero at the time of the peak during winter months, since these peaks typically occur after sunset. Forecast values for BTM PV are therefore assumed to be zero for all months other than May-September

(3) Compound Annual Growth Rate (%).

(4) Winter beginning in December of the year shown.

1.5.2 - Actual and Forecasted Energy

						2016 ACTUAL						
MONTHLY NET ENERGY - GWH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	12434	11484	11312	10417	10720	11387	13666	13937	11245	10734	10665	12340
Reduced for BTM PV	12371	11408	11181	10259	10559	11194	13473	13749	11098	10618	10580	12270
Reduced for BTM PV and PDR	11015	10126	9819	9020	9433	10176	12387	12642	10164	9356	9403	10840

						2017 FORECAST						
MONTHLY NET ENERGY - GWH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	12721 A	10786 A	11878 A	10267	10724	11578	13973	13362	11370	10642	10828	12044
Reduced for BTM PV	12164 A	10786 A	11878 A	10070	10520	11363	13748	13135	11178	10498	10715	11972
Reduced for BTM PV and PDR	10689 A	9404 A	10386 A	9088	9634	10549	12855	12216	10399	9463	9775	10730

						2018 FORECAST						
MONTHLY NET ENERGY - GWH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Without reductions	12857	11609	11711	10376	10838	11702	14121	13505	11491	10755	10943	12172
Reduced for BTM PV	12758	11506	11522	10126	10580	11431	13841	13222	11253	10578	10804	12084
Reduced for BTM PV and PDR	11483	10282	10214	9030	9592	10522	12844	12196	10385	9423	9756	10699

						ANNUAL						CAGR [3]
NET ANNUAL ENERGY - GWH [1, 2]	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017 to 2026
Without reductions	140341 A	140583	142078	143447	144611	145799	147127	148507	149884	151233	152593	0.92
Reduced for BTM PV	138761 A	138689	139705	140647	141478	142418	143518	144677	145857	147048	148255	0.74
Reduced for BTM PV and PDR	124382 A	126786	126426	125736	124440	122977	121859	120994	120349	119911	119680	-0.64

FOOTNOTES:

A = ACTUAL

(1) May not equal sum due to rounding.

(2) The Net Annual Energy does not include a reduction for Passive DR. With a reduction for PDR, the CAGR would be -0.2%. Refer to the ISO website for the full forecast details: http://www.iso-ne.com/system-planning/system-plans-studies/celt

(3) Compound Annual Growth Rate (%).

1.6 - Seasonal Peak Load Forecast Distributions (Forecast is Reference with reduction for BTM PV)

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2017	27148	27409	27748	28146	28571	29037	29511	30177	30954	31641
	2018	27319	27584	27928	28332	28764	29237	29718	30395	31183	31880
	2019	27503	27773	28122	28532	28970	29450	29938	30626	31426	32134
	2020	27702	27976	28330	28746	29191	29678	30174	30871	31683	32401
	2021	27925	28203	28562	28984	29436	29930	30432	31140	31964	32693
	2022	28162	28444	28808	29236	29694	30196	30705	31423	32259	32998
	2023	28406	28692	29062	29496	29960	30469	30986	31714	32562	33311
	2024	28655	28945	29320	29760	30231	30747	31271	32009	32869	33629
	2025	28910	29203	29584	30030	30507	31030	31562	32310	33182	33952
	2026	29166	29463	29849	30301	30785	31315	31854	32612	33496	34277
WTHI (1)		**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
Dry-Bulb Temperature (2)		**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
Probability of Forecast Being Exceeded		**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2017/18	22589	22712	22809	22874	23029	23185	23360	23466	23727	24107
	2018/19	22740	22863	22960	23025	23180	23337	23511	23617	23878	24258
	2019/20	22878	23002	23099	23164	23318	23475	23650	23756	24017	24397
	2020/21	22996	23120	23217	23281	23436	23593	23767	23874	24135	24514
	2021/22	23116	23240	23337	23402	23556	23713	23888	23994	24255	24635
	2022/23	23251	23374	23471	23536	23691	23848	24022	24128	24389	24769
	2023/24	23390	23514	23611	23676	23830	23987	24162	24268	24529	24909
	2024/25	23530	23653	23750	23815	23970	24127	24301	24407	24668	25048
	2025/26	23666	23790	23887	23952	24106	24263	24437	24544	24805	25185
	2026/27	23804	23927	24024	24089	24244	24401	24575	24681	24942	25322
Dry-Bulb Temperature (3)		**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

FOOTNOTES:

(1) WTHI - a three-day weighted temperature-humidity index for eight New England weather stations. It is the weather variable used in producing the summer peak load forecast. For more information on the weather variables see *http://www.iso-ne.com/system-planning/system-plans-studies/celt*.

(2) Dry-bulb temperature (in degrees Fahrenheit) shown in the summer season is for informational purposes only.

(3) Dry-bulb temperature (in degrees Fahrenheit) shown in the winter season is a weighted value from eight New England weather stations.

EXHIBIT RH-2

Introduction to New England's Forward Capacity Market

ISO 101

ISO new england

Disclaimer for Customer Training

ISO New England (ISO) provides training to enhance participant and stakeholder understanding.

Because not all issues and requirements are addressed by the training, participants and other stakeholders should not rely solely on this training for information but should consult the effective Transmission, Markets and Services Tariff (“Tariff”) and the relevant Market Manuals, Operating Procedures and Planning Procedures (“Procedures”).

In case of a discrepancy between training provided by ISO and the Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Introduction to New England's Forward Capacity Market

Table of Contents

Excerpt from:

Overview of New England's Wholesale Electricity Markets and Market Oversight

ISO New England Inc.

Internal Market Monitor

May 6, 2014

Forward Capacity Market

The Forward Capacity Market is a long-term wholesale market that assures resource adequacy, locally and systemwide. The market is designed to promote economic investment in supply and demand resources where they are needed most. Capacity resources may be new or existing resources and include supply from power plants, import capacity, or the decreased use of electricity through demand resources. To purchase enough qualified resources to satisfy the region's future needs and allow enough time to construct new capacity resources, Forward Capacity Auctions (FCAs) are held each year approximately three years in advance of when the capacity resources must provide service. Capacity resources compete in the annual FCA to obtain a commitment to supply capacity in exchange for a market-priced capacity payment.

This section describes the design of the Forward Capacity Market and FCAs as well as the financial-assurance mechanisms and oversight procedures in place for this market.

Capacity Requirements

The capacity needed to satisfy the region's systemwide future load and reliability requirements is called the *Installed Capacity Requirement* (ICR).[1] The *net Installed Capacity Requirement* (NICR) value is the ICR for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs).[2] Other key FCM inputs include locational capacity needs. These ensure that local areas secure sufficient capacity during the auction to maintain reliability when transmission constraints prevent the system from delivering the needed electric energy to the area. The transmission system constraints are based on the existing system network topology and transmission system upgrades certified by transmissions owners to be *in service* by the first day for the relevant capacity commitment period (CCP).[3] Transmission projects projected to go in service during the year are not included in the FCM auction assumption.

The locational information is provided for specific *capacity zones* (i.e., geographic subregions of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained). Import-constrained areas are assigned a *local sourcing requirement* (LSR) (i.e., the minimum amount of capacity that must be electrically located within these areas to meet the ICR). Export-constrained areas are assigned a *maximum capacity limit* (MCL)—the maximum amount of capacity that can be procured in these areas to meet the ICR.

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[1] The ICR is the minimum amount of resources (level of capacity) a balancing authority needs in a particular year to meet its resource adequacy planning criterion, according to the Northeast Power Coordination Council (NPCC) Regional Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year. The ICR is calculated in accordance with *Market Rule 1*, Section III.12 and is filed with FERC before each auction. For additional information on the loss-of-load-expectation criterion, refer to ISO New England's Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Bulk Power Supply System* (March 1, 2013), http://www.iso-ne.com/rules_proceds/isone_plan/pp03/index.html, and NPCC criteria, https://www.npcc.org/Standards/default.aspx and https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

[2] As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

[3] *In service* is when a unit or transmission line is available for use. A *capacity commitment period*, also known as a *capability year*, runs from June 1 through May 31 of the following year.

During each FCA, existing capacity resources are limited to a service period of one capacity commitment period, while new resources may commit to as many as seven[4] such periods at the FCA price. Performance penalties for delivery shortfalls during the service period ensure that resources purchased through the auction will be available when needed.

Resource Qualification

Because only resources with a capacity supply obligation (CSO) are required to offer into the Day-Ahead Energy Market, and because only the ICR amount is procured in the auction, it is critical for each FCA to procure only those capacity resources that will be commercial and available at the beginning of each capability year.[5] Although generating, demand, and import resources all may participate in the FCA to receive a CSO, the FCA treats new and existing capacity resources differently. Each type of resource has a distinctive qualification process designed to determine the amount of qualified capacity a particular resource can supply and to certify that each resource reasonably can be expected to be available during the relevant commitment period (approximately three years after the auction).

Existing Capacity Resource Qualification

The qualification process for existing capacity resources begins with the ISO's determination of each resource's *summer* and *winter qualified capacity*.[6] For generating capacity resources, the qualified capacity value relies on a resource's demonstrated performance over the previous five years. The summer and winter qualified capacity values for demand resources are calculated based on the sum of the previous qualified existing capacity and any incremental capacity that clears in the prior FCA.

At least two weeks before the existing capacity qualification deadline, the ISO notifies existing resources of their qualified capacity to allow time for participants to verify that their qualified capacity is correct or to seek redress by demonstrating that a different capacity quantity is appropriate. All existing resources are automatically entered into the capacity auction at their qualified value and assume a capacity supply obligation for the relevant commitment period, unless they submit a "delist bid" that subsequently clears in the auction.

Delist Bids

An existing resource can submit a *delist bid* for opting out of the capacity market for one year or permanently if the auction were to fall below a certain price. Several types of delist bids exist:

- *Static delist bids* are submitted for a resource before the existing capacity qualification deadline, which occurs approximately eight months before an FCA. These delist bids are for resources opting to remove all or part of their total capacity from the market for a single commitment period at a price greater than or equal to $1.00/kW-month. They may reflect either the cost of the resource or a reduction in ratings resulting from ambient air conditions.[7] The ISO may be required to submit a static delist bid on behalf of a resource if the resource, or combination of resources using an offer composed of separate resources, will not be able to supply its awarded

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[4] Changed from five to seven periods on May 30, 2014

[5] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement acquired through an FCA, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all or part of its CSO to another entity.

[6] The methodology for qualifying existing capacity resources is contained in *Market Rule 1*, Section III.13, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_13-14.pdf.

[7] "Ambient air" delist bids are those made to reflect a thermal generator's difference in capacity rating at 90 degrees Fahrenheit (°F) and at 100°F.

capacity during the entire commitment period. A lead participant may withdraw a static delist bid during a defined window, which occurs approximately four months before an FCA.

- *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids are only offered below $1.00/kW-month, and the Internal Market Monitor does not oversee these bids (see below).
- *Permanent delist bids* represent a binding request to remove the resource's capacity from the capacity market permanently at a certain price. Capacity associated with a permanent delist bid may only reenter the capacity market if they qualify for, and clear, as a new resource in a subsequent FCA. Permanent delist bids are submitted for a resource before the existing capacity qualification deadline.
- *Nonprice retirement requests*, which are irrevocable requests to retire all or a portion of a resource, supersede any other delist bids submitted. Nonprice retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue to operate it until the reliability need has been met. Once the reliability need has been met, the resource must retire.
- *Export delist bids* are bids to exit the New England capacity market and sell capacity to a neighboring area. The cost of an export delist bid may include an opportunity-cost component of selling capacity to a neighboring market.
- *Administrative export delist bids* are submitted for capacity exports associated with multiyear contracts and are initiated using the same requirements as for export delist bids.

To provide market transparency to potential new capacity suppliers, all delist bids submitted during the qualification process are posted in advance of the FCA, with the exception of dynamic delist bids, which are submitted during the auction. The ISO reviews all delist bids for reliability purposes. Except for permanent delist bids and nonprice retirement requests, all delist bids are effective for the relevant commitment period only.

Internal Market Monitor Oversight

To address market power concerns, during the qualification process, the IMM reviews certain delist bids to determine whether bid prices are consistent with a resource's net risk-adjusted going-forward costs and opportunity costs as specified in the rules. All delist bids, except dynamic delist bids, must include sufficient documentation for the Internal Market Monitor to make these determinations; the Internal Market Monitor may reject delist bids that have insufficient supporting documentation for the delist price. Static delist bids, export delist bids, and permanent delist bids above $1.00/kW-month are subject to Internal Market Monitor review. Delist bids submitted below $1.00/kW-month are presumed to be competitive.

The IMM does not review ambient air delist bids or administrative export delist bids. The IMM also does not review dynamic delist bids submitted during the auction at prices below 1.00/kW-month.

No later than 127 days before the auction, the ISO must notify participants regarding whether their delist bids are qualified to participate in the FCA. All accepted delist bids are entered into the auction. For delist bids excluded from the auction as a result of the Internal Market Monitor's review, the ISO will explain in the notification correspondence the specific reasons for not accepting the bid and the Internal Market Monitor's derivation of an alternate delist price. The participant may opt to use this alternate price, subject to applicable market rules and by informing the Federal Energy Regulatory Commission (FERC).

No later than 7 days after the ISO notifies participants whether or not the Internal Market Monitor accepted their delist bids, participants with a static delist bid may elect to withdraw the bid entirely or submit revised prices for the resource's bid. The revised prices for the static delist bids must be equal to or less than the highest price indicated in the initial bid, as approved by the Internal Market Monitor and greater than $1.00/kW-month.

Qualification Process for New Capacity Resources

Like existing resources, new supply-side and demand-side resources must undergo a qualification process to be able to participate in the FCM. Additionally, some resources previously counted as existing capacity (including deactivated or retired resources) and incremental capacity from existing resources may opt to be treated as new capacity resources in the FCA, subject to certain requirements.

To keep barriers to entry low and increase competition, the financial assurance required from new capacity suppliers is relatively low. A minimal level of credit enables more competitors to enter the market because they are not required to assume a relatively large financial guaranty during the project's development. However, because new commitments can be backed by a relatively low amount of financial security, they must undergo a rigorous qualification process and demonstrate that they can provide the capacity they plan to offer in the auction. This process ensures that any new project that clears in an auction can be interconnected before the delivery period and that the participant can back all capacity obligations with tangible assets to build the project.

New Supply-Side Resources

For new power plant proposals, the ISO conducts several studies to ensure that a generator can connect to the power grid electrically without having a negative impact on reliability or violating safety standards. The qualification review also assesses the project's feasibility (i.e., whether it realistically can be built and commercialized before the beginning of the relevant capability year). The ISO also must evaluate each new supply-side resource to ensure that it will be able to provide effective incremental capacity to the system. An overlapping impact analysis for each new supply-side resource assesses whether the resource can provide useful capacity and electric energy without negatively affecting the ability of other capacity resources to provide these services also.

The first step to qualify a new capacity resource is for project sponsors to submit a new capacity show-of-interest (SOI) form. The SOI form is a short application that requests a minimum amount of information (e.g., interconnection point, equipment configuration, megawatt capacity). The next step is for the project sponsors to submit a completed qualification package for the project by the new capacity qualification deadline (approximately 8 months before the FCA). This package must include all the data required for the ISO to evaluate the interconnection of the project and its feasibility. Also at this time, new import-capacity resources must provide documentation indicating the interface from which the capacity will be imported, the source of the capacity (from an external generating resource or from an adjacent balancing authority area), and the import's summer and winter capability ratings.

New Demand-Side Resources

Demand-reduction resource proposals undergo a feasibility review, during which the ISO ensures that the plans and methods for reducing electricity use meet industry standards. This is the primary mechanism for assessing demand-response project criteria because these projects have no interconnection impact.[8] For this review, demand resources submit a measurement and verification plan, which outlines the project and its development and how the resource will achieve the demand reduction. The ISO subsequently reviews this plan for completeness and to determine how much capacity the resource can provide.

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[8] *Demand response* is when a market participant reduces its consumption of electric energy from the network in exchange for compensation based on wholesale market prices.

Internal Market Monitor Oversight

Per *Market Rule 1*, new resources are given a stated price, known as the offer-review trigger price (ORTP), up to which point the resource may remain within the auction. The IMM developed a menu of ORTPs for various resource types, which approximate the net cost of entry of each resource. The ORTP establishes a floor price for a new resource, below which it must leave the auction, absent a request submitted to the IMM to offer at a price lower than the relevant ORTP. New resources that might submit offers in the FCA at prices below the relevant ORTP must include in the new capacity qualification package the lowest price at which the resource requests to offer capacity, along with supporting documentation justifying that price as competitive in light of the resource's costs. If the IMM determines that the offer is consistent with the long-run average costs, the resource will be allowed to remain in the auction up to the validated price.

Notification and Filing

No later than 127 days before each FCA, the ISO notifies each sponsor engaged in the qualification process regarding whether its new capacity resource has been accepted for participation in the FCA. If the project sponsor of a resource indicated an intention to offer capacity below its ORTP, the results of the Internal Market Monitor's assessment are also provided at this time. Additionally, the ISO files all qualification results and auction inputs with FERC. This informational filing is made approximately three months before the ISO conducts the auction and provides interested parties the opportunity to review and comment on the ISO's fulfillment of its responsibilities before conducting the FCA.

Auction Design

Each Forward Capacity Auction is conducted in two stages; a descending-clock auction followed by an auction clearing process. The descending-clock auction, run by an auctioneer, consists of multiple rounds. Before the beginning of each round, the auctioneer announces to all participants the start-of-round and end-of-round prices. During the round, participants submit offers expressing their willingness to keep specific megawatt quantities in the auction at different price levels within the range of the start-of-round and end-of-round prices. During one of the rounds, the capacity willing to remain in the auction at some price level will equal or fall below the net Installed Capacity Requirement. FCM resources still in the auction at this point pass on to the auction-clearing stage.

Table 1 shows the hypothetical result of a descending-clock FCA with a starting price of $15.00/kW-month. Additional assumptions built into this example are that the NICR equals 30,000 MW; 23,000 MW of existing capacity will be participating, thus 7,000 MW of new resources will be needed to meet the NICR; and 15,000 MW of new capacity will be participating.

Table 1: Sample Results from a Descending-Clock Forward Capacity Auction Round

Round Number	Start-of-Round Price ($/kW-mo)	End-of-Round Price ($/kW-mo)	End-of-Round Resource (MW)	Excess Capacity (MW)
1	$15.00	$9.50	38,000	8,000
2	$9.49	$9.00	32,500	2,500
3	$8.99	$8.00	32,000	2,000
4	$7.99	$7.50	31,000	1.000
5	$7.49	$7.00	30,750	750
6	$6.99	$6.00	29,800	−200

All the capacity resources remaining in the auction at the end of round six pass through to the second stage of the FCA. In this stage, the market-clearing auction software is run to determine the minimal capacity payment and to calculate final capacity-zone clearing prices. This step also includes a post-processing procedure that determines the final payment rate for each resource and its capacity supply obligation for the capacity commitment period. Thus, using the example shown in Table 1, after the sixth round, the market-clearing auction software would be run to determine the resources and the price that would minimize the cost at a purchase amount of 30,000 MW. The final capacity-zone clearing price in this example would equal some value between the round six start-of-round price and end-of-round price.

Reconfiguration auctions take place before and during the commitment period to allow participants to buy and sell capacity obligations and adjust their positions. These auctions are needed to add capacity to cover for potential increases in the ICR, to release capacity to match potential decreases in the ICR, and to defer capacity requirements associated with existing capacity delist bids. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the FCA commitment period begins. Monthly reconfiguration auctions, held beginning the first month of the first commitment period, adjust the annual commitments during the commitment period.

Capacity Payments

Resources with capacity supply obligations are paid the auction clearing price. However, two key provisions of the capacity payment structure are the *peak energy rent* (PER) adjustment and penalties incurred for unavailability during *shortage events*. The PER adjustment reduces capacity market payments for all capacity resources when prices in the electric energy markets go above the PER threshold (i.e., *strike*) price, which is an estimate of the cost of the most expensive resource on the system. This usually occurs when electricity demand is high. PER provides an additional incentive for capacity resources to be available during peak periods because capacity payments are reduced for all listed resources, even those not producing energy when the LMP exceeds the PER threshold price. PER also discourages physical and economic withholding in the energy market because a resource that withholds to raise price does not earn energy revenues, while its foregone revenues are deducted from the capacity market settlement.

Shortage events are periods when reserves fall below the system reserve requirements for 30 minutes or more. Shortage-event availability penalties are assessed for resources that have capacity supply obligations but are unavailable during defined shortage events. The availability penalties are a disincentive to withhold in the energy market.

OCTOBER 1, 2014 | WESTBOROUGH, MA

Introduction to New England's Forward Capacity Market

ISO 101

Andrew Gillespie
PRINCIPAL ANALYST
MARKET DEVELOPMENT

Topics

- Capacity Market Basics
- How the FCM Works
- Current Issues & Changes to Address Them
- Additional Training Available

CAPACITY MARKET BASICS

- *Capacity Markets and Why They Are Needed*
- *What is the Forward Capacity Market?*

Capacity

Capacity is, and is needed:

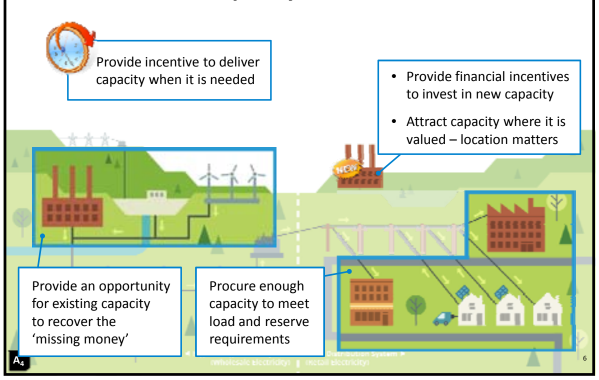
- To address specific system needs
- So special events on the system do not place the grid at risk
- Depends on where, when, and how it gets delivered

NPCC's Definition of Capacity:
The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
(Source: NPCC Glossary)

Why Have a Capacity Market?

- For some resources, infrequent dispatch provides limited opportunities to fully recover fixed costs
  - Energy prices may not be high enough for long enough
  - Expenditures not recovered in the energy and ancillary service markets is often called the 'missing' money
- This is not just a peaking resource problem
  - Base load generation can be very capital intensive - there may still be a missing money problem due to the size of the initial investment

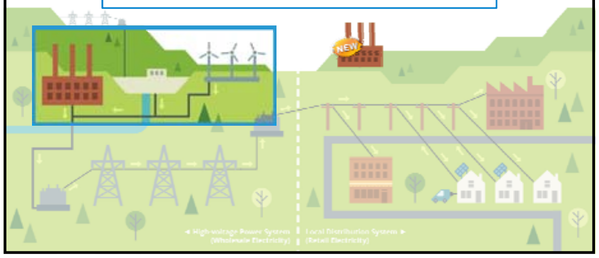
What Should a Capacity Market Do?



What Should a Capacity Resource Do?

In exchange, capacity resources must *at least*:

- Offer into the Energy Market
- Schedule maintenance with ISO



The Forward Capacity Market (FCM) is…

…a forward procurement, auction-based, Locational Capacity Market

Goal 1:

Ensure reliability of the New England grid:
- Send appropriate price signals to attract new investment, including demand resources
- Maintain existing resources where and when they are needed

Goal 2:

Provide market-based measure of the cost of new entry
- Allows new capacity (capacity not yet 'built') to set market clearing price
- Still accounts for locational capacity requirements

8

HOW THE FCM WORKS

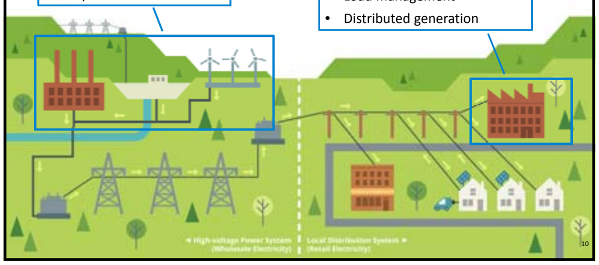
- *Resource Types and Qualification*
- *Capacity Commitment Period*
- *Forward Capacity Market Process*
- *System Topology*
- *Total Amount Procured*

9

Types of Resources Involved in the FCM

- Traditional generation
- Intermittent generation
- Imports

- Energy efficiency
- Load management
- Distributed generation



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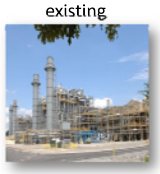
Resource Qualification

Resource Qualification

- FCA is designed to procure only those capacity resources that will be commercial and available at the beginning of each capability year
- FCA treats new and existing capacity resources differently

new

existing



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New Capacity Resources

Resource Qualification

- Project sponsors must for *supply-side* resources:
  - Submit a Show of Interest (SOI) form
  - Submit a completed qualification package
  - Provide detailed documentation (import interface, source of capacity, summer/winter capability)
- Project sponsors must for *demand-side* resources:
  - Undergo a feasibility review
  - Outline how demand reduction will be achieved
- Financial Assurance is required
- New resources offer into market, but cannot submit an offer at a price that is below the resource's minimum offer price

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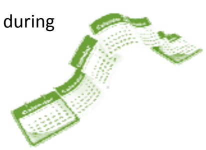
Existing Capacity Resources

- ISO determines summer and winter qualified capacity for each resource
- Existing resources are automatically entered into the capacity auction based on their qualified capacity
- To opt out of the capacity market, existing resources can submit a de-list bid
  - Can be for one year or permanently
  - Internal Market Monitor provides oversight of most de-list bid types
  - System Planning will review reliability impact

13

Capacity Commitment Period (CCP)

- The CCP is a 12 month period, including one Summer period (June – September) and one Winter period (October – May)
  - not a calendar year
- Capacity resources must offer into the energy market and schedule maintenance with the ISO
- *Currently*, if the resource is available during a scarcity, the resource is deemed delivering its 'capacity'



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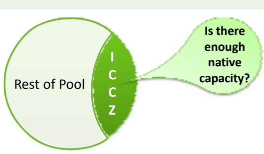
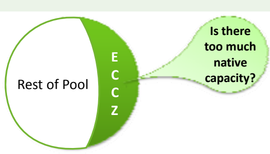
System Topology

Each year the ISO reviews with stakeholders what zones will be used in the FCA

Import-constrained capacity zones (ICCZ)	Export-constrained capacity zones (ECCZ)
Import constrained capacity zones (ICCZ) have limited ability to 'import' energy into that zone.	Export-constrained capacity zones (ECCZ) have a limited ability to 'export' energy from that zone.





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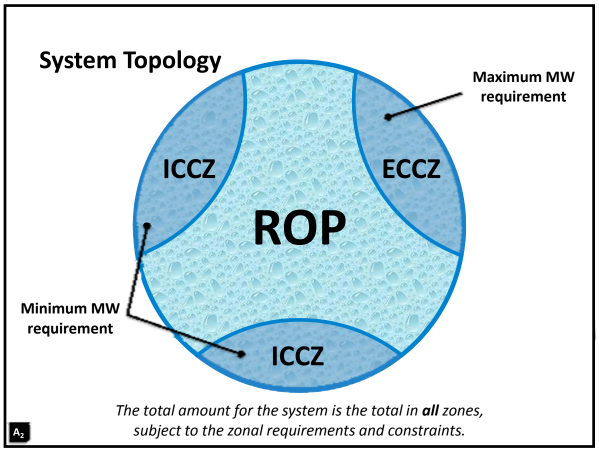
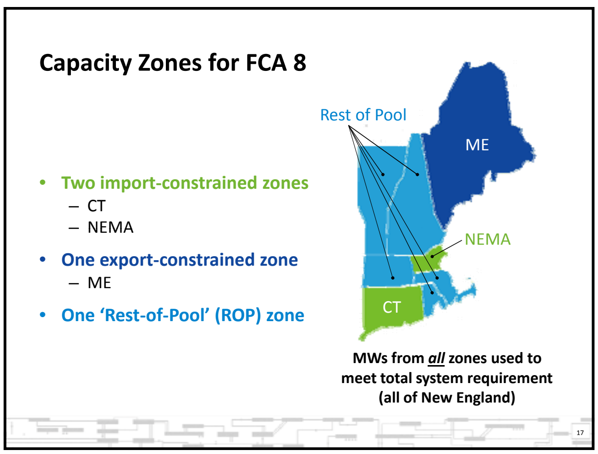

System Topology
Maximum MW requirement
ICCZ
ECCZ
ROP
Minimum MW requirement
ICCZ
The total amount for the system is the total in **all** zones, subject to the zonal requirements and constraints.


Capacity Zones for FCA 8
Rest of Pool
ME
NEMA
CT
• Two import-constrained zones
– CT
– NEMA
• One export-constrained zone
– ME
• One 'Rest-of-Pool' (ROP) zone
MWs from *all* zones used to meet total system requirement (all of New England)
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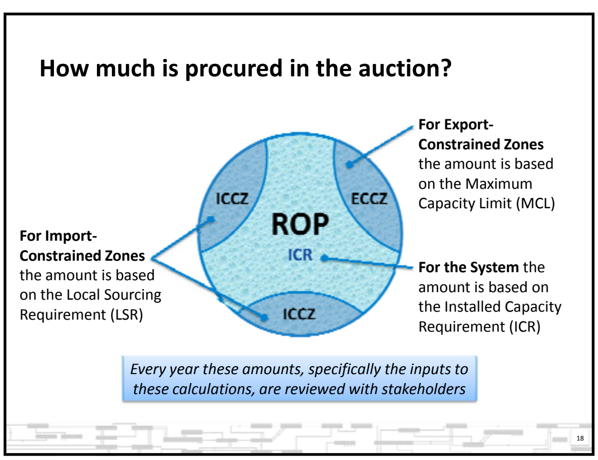
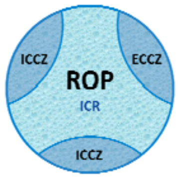
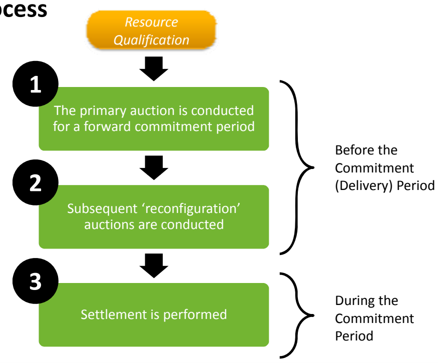

How much is procured in the auction?
For Export-Constrained Zones the amount is based on the Maximum Capacity Limit (MCL)
ICCZ
ECCZ
ROP
ICR
ICCZ
For Import-Constrained Zones the amount is based on the Local Sourcing Requirement (LSR)
For the System the amount is based on the Installed Capacity Requirement (ICR)
Every year these amounts, specifically the inputs to these calculations, are reviewed with stakeholders
18

What is Installed Capacity Requirement (ICR)?

- ICR is the amount of capacity needed such that the probability of disconnecting non-interruptible customers due to resource deficiency is no more than once in ten years
- Some of the factors considered in determining the ICR amount are:
  - Weather variations on load forecasts
  - Resource equivalent forced outage rates
  - Reliability benefits from interconnections with adjacent control areas



FCM Process



The Forward Capacity Auction (FCA)

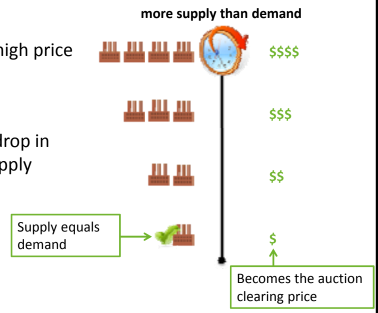
1

- The FCA is conducted approximately 3 years before the commitment period
- Resources must qualify to participate, which ensures resources are 'real'
  - This process however, requires that qualification start approximately 4 years before the commitment period
- The FCA uses a descending clock auction format
  - Given the stakes involved this format provides for more informed bidding, and hence more efficient pricing outcomes

Concept of a Descending Clock Auction

1

- Auction starts at a high price
- Price is lowered in increments
- Price continues to drop in increments until supply meets demand
- Auction stops



22

Annual Reconfiguration Auction (ARA)

2

- Three ARAs are conducted between the FCA and the commitment period
- Provides opportunity for:
  - Suppliers to swap obligations
  - ISO to adjust total purchased amount

23

CURRENT ISSUES & THE CHANGES TO ADDRESS THEM

- *Brief History of the FCM (How did we get here?)*
- *Price Volatility*
- *Resource Performance*

24

Brief History of the FCM

2004	Locational Capacity Market
2004-2006	Settlement Agreement discussions
2006-2011	Establishment of FCM using SA framework
2011-present day	Creation and utilization of a sloped demand curve to dampen price volatility
	Modification of market structure to create incentives to achieve desired outcomes

Current Issues:

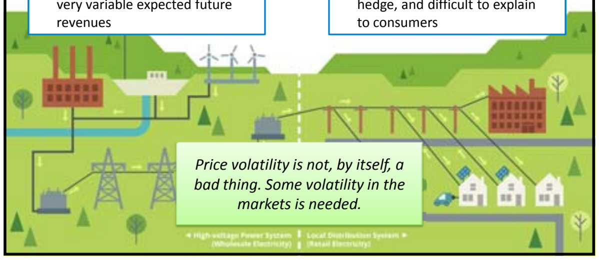
Price Volatility | **Resource Performance**

Price Volatility
The Issue

Too Much Price Volatility

Bad for suppliers
- Difficult to finance a project with very variable expected future revenues

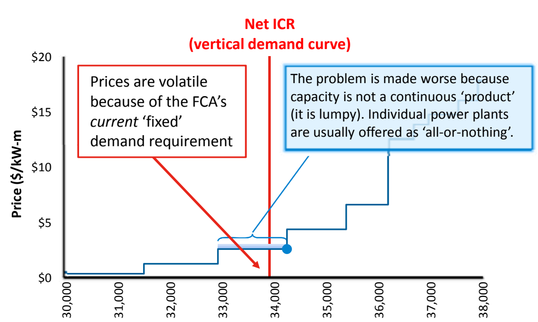
Bad for buyers/demand/load
- Price shocks are difficult to hedge, and difficult to explain to consumers



Price volatility is not, by itself, a bad thing. Some volatility in the markets is needed.

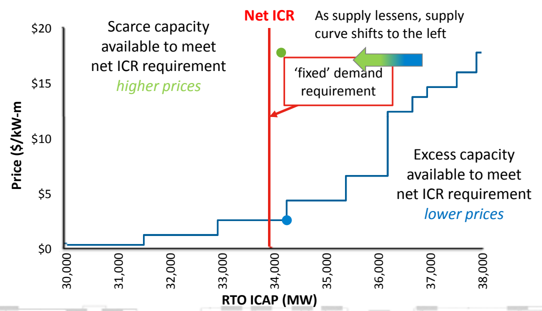
Price Volatility
The Problem

Price Volatility



Why Is Price Volatility an Issue?

Price Volatility
The Problem



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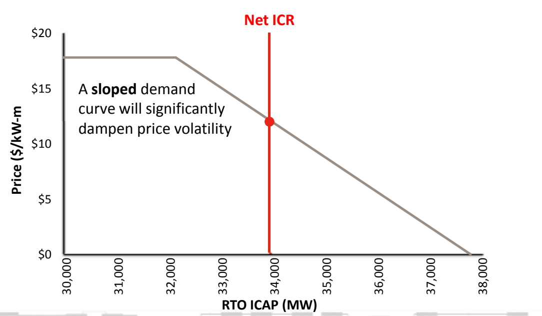
Sloped Demand Curve

Price Volatility
The Changes



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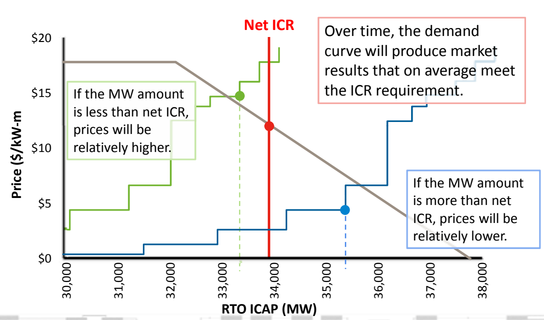
Concept Behind the Shape and Slope of the Demand Curve

Price Volatility
The Changes



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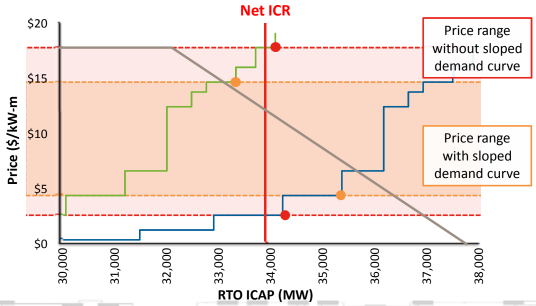
Concept Behind the Shape and Slope of the Demand Curve

Price Volatility
The Changes



Resource Performance

Resource Performance
The Issue

- Capacity resources are used day-to-day but are really needed when the system is stressed
  - high loads
  - contingencies
- When the system is stressed, the ISO cannot meet both the load and the reserve requirement with the resources at hand
  - When the reserve requirement is not being met, the reserve price is at a maximum (at the Reserve Constraint Penalty Factor price)

Paying a resource to 'be there' has not been sufficient incentive for a resource to make a meaningful contribution when 'capacity' is really needed.

Why Is Performance an Issue?

Resource Performance
The Problem

- Current metric of 'availability' does not incent sufficient performance when the system is deficient
  - July 19, 2013 – There were no reductions in payments for the capacity that was out or reduced

Net Capability Required	29,751 MW
Capacity Margin	(547) MW
Outages & Reductions	4,611 MW

- Availability (or lack of) is not a meaningful component in a resource's offer price
  - 'Performance' is undervalued in the supply stack of offers

New Performance Metric

Resource Performance

The Changes

- Metric will be the delivered energy and/or reserves during periods of system stress
  - This is a two-settlement construct
- Offers to sell capacity will now reflect, in addition to a resource's going forward costs (i.e., avoided costs) the resource's expected performance during scarcity conditions
- During the commitment period
  - A resource will get a base payment
    - Paid by load
  - A resource will be subject to a delivery settlement
    - Transfer between suppliers

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Benefits of the Two-Settlement Design

Resource Performance

The Changes

- Greater operational- related investments at existing resources to improve resource performance
  - For example, dual-fuel arrangements
- Efficient resource evolution – those that deliver will get rewarded
- A more reliable system at lowest possible cost

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Topics Covered

- Capacity Market Basics
- How the FCM Works
- Current Issues & Changes to Address Them
- Additional Training Available

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Summary

The Forward Capacity Market is designed to:

- Procure enough capacity to meet load and reserve requirements
- Attract capacity where it is needed (location matters)
- Helps with the 'missing money' problem by:
  - Providing an opportunity for existing capacity to recover costs
  - Providing a financial incentive to invest in new capacity when needed

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Additional Training Available

- 2014 Instructor Led Training
  (class materials available at iso-ne.com/participate/training/materials)
  - WEM 101 (4.5 day class)
    - Course schedule for 2015 to be announced
  - FCM 101 (4 day class)
    - October 20-23, 2014 in Northampton, MA
- 2014 Webinars
  (recordings available at iso-ne.com/participate/training/elearning-opportunities)
  - Demand Resources Show of Interest for the Ninth Forward Capacity Auction 2018-19 (1/22/2014)
  - New Generation & Imports Show of Interest for the Ninth Forward Capacity Auction 2018-19 (1/23/2014)
  - Existing Capacity Qualification (4/3/2014)
  - New Capacity Qualification – Demand Resources (5/7/2014)
  - New Capacity Qualification – Supply Resources (5/8/2014)
  - FCM Reconfiguration Auction (9/5/2014)
- Web-Based Training Modules
  - Financial Assurance for the Forward Capacity Market (1/2014)

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<u>EXHIBIT RH-3</u>

ISO new england

PRESS RELEASE

FOR IMMEDIATE RELEASE

Contact:
Ellen Foley (413) 535-4139
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Jeffrey Jurgensmier (413) 540-4483

ISO-NE Capacity Auction Secures Sufficient Power System Resources, At a Lower Price, for Grid Reliability in 2019-2020

2016 auction clearing price is 25% lower than last year's auction

Holyoke, MA—February 11, 2016—New England's annual capacity auction concluded Monday with sufficient resources to meet demand in 2019-2020, at a lower price, and with more than 1,400 megawatts (MW) of new generating capacity that will help replace recently retired and retiring generators. The auction is run by ISO New England Inc. to procure the resources that will be needed to meet projected demand three years in the future.

The tenth Forward Capacity Market (FCM) auction (FCA #10) attracted significant competition among resources to provide reliability services in New England. Before the auction, a total of 40,131 MW of resources, including 6,700 MW of new resources, qualified to compete in the auction to provide the 34,151 MW Installed Capacity Requirement (ICR) for 2019-2020.

"Competition was robust in this year's Forward Capacity Auction," said Gordon van Welie, president and CEO of ISO New England. "The high participation in the auction demonstrates the interest in the New England marketplace and bodes well for meeting future resource adequacy requirements."

Recent and pending retirements of coal, oil, and nuclear power plants expected to shut down by 2019 total more than 4,200 MW, including the 680 MW Pilgrim Nuclear Power Station that announced its retirement before this auction.

"Developers were drawn to the New England marketplace because the price of capacity supports construction of new resources," continued van Welie. "It's important to have a capacity market that places an appropriate value on the product to maintain an adequate supply. This auction procured the resources needed to keep the lights on in New England at a price lower than last year's auction and, in fact, lower than the estimated cost of building a new power plant. More than 850 megawatts of new generating capacity cleared in the Greater Boston, Southeast Massachusetts and Rhode Island zone where the resources are needed most."

Preliminary results of FCA #10:

- About 35,567 MW of capacity cleared the auction to meet the 34,151 MW ICR for 2019-2020. (The region can acquire more or less than the specific capacity requirement, depending on reliability standards and price.)
    - 31,371 MW of generation, including 1,459 MW of new generation
    - 2,746 MW of demand-side resources, including 371 MW that is new
    - 1,450 MW of imports from New York and Canada

Preliminary clearing price:

- The auction closed for resources within New England after four rounds of competitive bidding at $7.03/kW-month, at the point on the demand curve where there were still sufficient resources to meet demand. The clearing price will be paid to all resources in both capacity zones in the region. *[Clarification]* Imports from Quebec over Phase II and Highgate also cleared at $7.03/kW-month.
- The clearing price was more than 25% lower than last year's $9.55/kW-month for most resources. The lower clearing price demonstrates strong competition among resources and also illustrates that the capacity market is continuing to work: higher prices resulting from resource shortfalls in earlier auctions provided the incentives for developers to bring new—and needed—resources to the market.

- At $7.03/kW-month, the total value of the capacity market in 2019-2020 will be approximately $3 billion, compared to the estimated $4 billion for 2018-2019.
    - The price of $7.03/kW-month is less than the pre-auction estimate of the cost of building a new natural-gas-fired power plant in New England, at $10.81/kW-month

- The auction continued for a fifth round for 181 MW of New Brunswick imports, which will receive $4.00/kW-month. New York imports totaling 1,044 MW, which cleared in the fourth round, will receive a price of $6.26/kW-month.

Highlights of FCA #10:

- **Three large, new, dual-fuel power plants totaling 1,302 MW** cleared the auction. The proposed plants are all near the region's largest population centers, and two are in the former Southeast Massachusetts/Rhode Island zone, where a capacity shortfall materialized before last year's auction for 2018-2019. All three will burn natural gas as their primary fuel, with oil as their secondary fuel:
  - About 485 MW of the Burrillville Energy Center 3 in Burrillville, Rhode Island
  - 484 MW at Bridgeport Harbor 6 in Bridgeport, Connecticut
  - 333 MW at Canal 3 in Sandwich, Massachusetts
- **27 megawatts of new wind** and **44 megawatts of new solar** cleared the auction; in all, 135 MW of wind and 65 MW of solar facilities cleared FCA #10

Several firsts, including:

- 6.8 MW from the first offshore wind farm under construction in the US cleared the auction: Deepwater Wind's 34-MW facility off Block Island, RI
- With the development of the first, multi-state, long-term forecast of solar growth in the nation, small-scale solar facilities around New England were incorporated into the calculation of how much capacity will be required. Forecasted demand reductions from solar reduced the ICR in 2019-2020 by 390 MW.
- Two large fuel cell facilities, providing 2.5 MW each, cleared the auction.

For FCA #10, the region was divided into two zones: Rest of Pool (ROP) which includes Connecticut, western and central Massachusetts, Vermont, New Hampshire, and Maine; and Southeastern New England (SENE), which includes Northeast Massachusetts/Greater Boston and Southeast Massachusetts/Rhode Island. The SENE zone was created based on transmission limitations that restrict the level of power that can be imported into the area, as well as local resource levels and needs. The clearing price in FCA #10 applies to resources in both zones.

Market design changes now in effect

Several significant FCM enhancements went into effect with last year's auction, including Pay for Performance incentives. The market redesign work by ISO New England, market participants, policymakers and regulators, and others, is helping remove risks from the market and providing developers with the financial stability needed to invest in new resources. The enhancements also provide consumers with greater assurance that the region's power system will have sufficient capacity to keep the lights on, and that those resources will perform when called on. These market changes, as well as other steps taken by the ISO, helped incentivize the 1,302 MW of new, dual-fuel power plants that cleared FCA #10. These dual-fuel generators will enhance reliability because if one fuel is unavailable, they can turn to the second fuel.

Forward Capacity Market auction basics

The annual FCM auction is held three years before each capacity commitment period to provide time for new resources to be developed. Capacity resources can include traditional power generation, renewable generation, or demand-side resources such as load management and energy-efficiency measures. Resources that clear in the auction will receive a monthly capacity payment in that future year in exchange for their commitment to provide power or curtail demand when called upon by the ISO. The capacity market is separate from the energy market, where resources compete on a daily basis to provide power, and are paid for the electricity they produce.

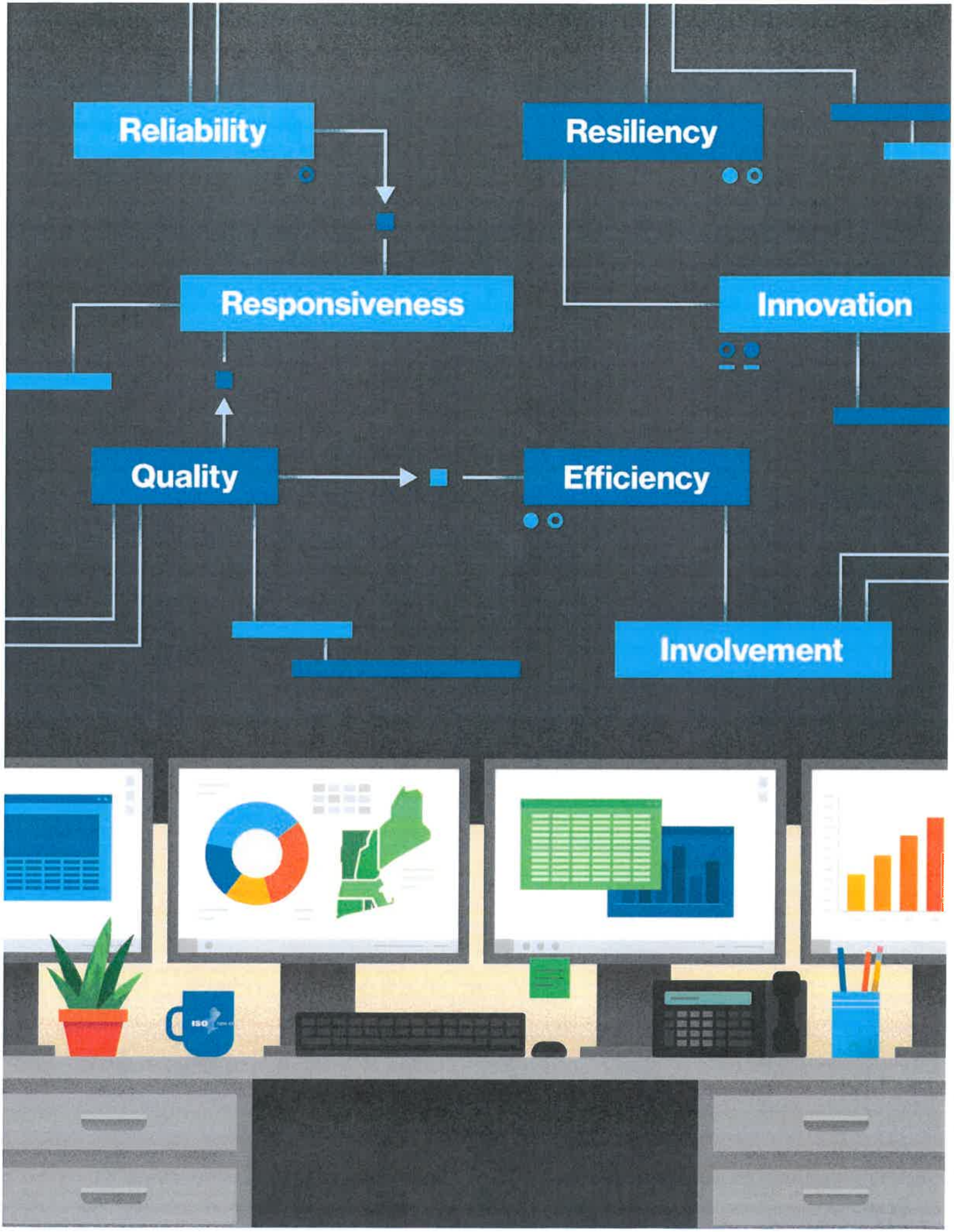
Next Steps

Finalized auction results will be included in a filing with the Federal Energy Regulatory Commission within the month. The finalized results filing will include resource-specific information.

EXHIBIT RH-4

ISO new england | 20 years

2017 Regional Electricity Outlook


Reliability
Resiliency
Responsiveness
Innovation
Quality
Efficiency
Involvement
ISO

Contents

About this Report

ISO New England's unique role gives it an objective, bird's-eye view of trends that could impact the region's power system. The *Regional Electricity Outlook* is one of the many ways the ISO keeps stakeholders informed about the current state of the grid, issues affecting its future, and ISO actions to ensure a modern, reliable power system for New England. Also see our Annual Work Plan at **www.iso-ne.com/work-plan** for information on the ISO's major projects for the year to improve our services and performance. Contact ISO New England's Corporate Communications and External Affairs teams at (413) 535-4309 for copies of this report.

Please note: The facts and figures in this report were current at publication in January 2017. However, the ISO continually generates **data and analyses**.

For the most current information, please visit www.iso-ne.com/reo.

About Us

ISO New England is the not-for-profit corporation responsible for keeping electricity flowing across the six-state New England region: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The company's power system engineers, economists, computer scientists, and other professionals ensure that the region has reliable, competitively priced wholesale electricity today and into the future. The ISO is independent – none of the ISO's board members, officers, or employees has a financial interest in any company doing business in the region's wholesale electricity marketplace. The Federal Energy Regulatory Commission regulates the ISO.

Our Mission

ISO New England's mission includes **three interconnected responsibilities**:

- **Overseeing** the day-to-day operation of New England's electric power generation and transmission system
- **Managing** comprehensive regional power system planning
- **Developing** and administering the region's competitive wholesale electricity markets

From the Board Chair

Philip Shapiro joined the ISO Board in 2010 and was named chair in 2014. He has extensive experience in finance and infrastructure. Read his full bio at **www.iso-ne.com/about.**

In our electrified world, a robust, state-of-the-art power system and thriving wholesale electricity marketplace are becoming more important for New England's consumers, its economy, and its environmental goals. As more renewable and distributed generation comes on line, the regional power system will remain an indispensable source of primary power for many, backup power for some, and a low-carbon power source for the transportation and heating sectors seeking to meet emissions requirements from the New England states.

This year marks our twentieth of successfully running the grid in New England, ensuring that the region's residents and businesses have electricity whenever and wherever they need it. During this time, we've also helped New England develop a highly efficient, reliable transmission system and competitive marketplace that, together, have facilitated an evolution in the region's generating fleet. This has helped decrease air emissions and wholesale electricity prices.

As we have done for the past two decades, the ISO will keep spotlighting the physical and economic factors that can impact reliability. A change in one area of the industry can send out ripples that require adjustments in other areas, an effect illustrated by the region's shift to natural-gas-fired generation and renewable resources. Most urgent is the need to address growing concerns over the ability of natural-gas-fired generators to dependably access

Philip Shapiro
Board Chair

"As we have done for the past two decades, the ISO will keep spotlighting the physical and economic factors that can impact reliability."

adequate fuel during winter cold snaps. Without a timely solution, this fuel-security issue could put reliability at risk, as well as drive up costs and derail progress on meeting the states' clean-energy goals. Actions being taken or considered by the states to reach those goals, meanwhile, may inadvertently undercut the ability of the wholesale marketplace to continue delivering on its promise of securing reliable, competitively-priced electricity for New England today and into the future.

The ISO's independence, objective analyses, and long-term perspective are an asset to the region as we all try to navigate these uncharted waters. I am confident that the ISO and its dedicated professionals will take the necessary actions to protect the reliability of the power system and the integrity of the wholesale electricity marketplace designed to secure that reliability.

The strong collaborative spirit that exists among the ISO, public officials, and regional stakeholders—the market participants and consumer and environmental advocates in the area—will be key in the coming years as we attempt to leverage new technologies and stay ahead of the many challenges presented by our rapidly evolving industry. Working together, we can ensure that as New England strives to create the power system it wants, it also creates the power system it needs.

Sincerely,

From the CEO

Gordon van Welie has been president and chief executive officer of ISO New England since 2001. Read his full bio at **www.iso-ne.com/about**.

Like many at ISO New England, I am concerned about keeping the lights on in coming winters. We prepare year-round and years ahead for challenging winter conditions because we know that New England depends on the constant flow of electricity that drives the economy and keeps families warm and safe. But the fact is that reliable winter operations are becoming increasingly difficult, particularly during cold snaps.

At the heart of the problem are factors that the ISO has been warning about for some time now but does not have the authority to directly address. On the coldest days of the year, natural-gas-fired power plants can't always access adequate gas because natural gas transportation and storage infrastructure hasn't kept pace with demand from the electricity sector. This is a real risk to reliability—nearly half the region's current electric generating capability and roughly half the proposed new capability

"We prepare year-round and years ahead for challenging winter conditions because we know that New England depends on the constant flow of runs primarily on this fuel type. During the winter, generation that is not fueled by natural gas has been used to fill the gap, including resources that run on nuclear power, oil, and coal—the latter two of which have caused upticks in winter air emissions. However, these resources have begun to close down and leave the system because they are either less efficient, less profitable, or both. Replacing them will be even more natural-gas-fired generation, to a large extent.

Renewable power resources have also been coming on line quickly, and a number of New England states are moving to significantly increase the amount of renewable energy on the grid, as well as to further reduce emissions from fossil-fuel-fired generators. The ISO has been actively refining systems and market rules to integrate renewable resources, which currently make a valuable, and growing, contribution to offset some of the region's reliance on natural gas and will become integral to achieving a clean-energy future. Still, the region is decades away from installing enough renewable resources and grid-scale energy storage to allow for complete independence from fossil fuels. Connecting additional remote clean-energy resources is also going to require improvements on the transmission system.

electricity that drives the economy and keeps families warm and safe."

Gordon van Welie
President and CEO

“The region is decades away from installing enough renewable resources

For the foreseeable future, the region will require resources such as natural-gas-fired units that can do what wind and solar resources cannot: make large contributions to meeting regional electricity demand; run in any type of weather and at any time of day; quickly change output levels; and provide essential grid-stability services. On frigid winter days in particular, the region has no alternative but to depend on fossil fuels and the remaining nuclear power stations, while also working to improve fuel accessibility for natural-gas-fired generators. The latter will be particularly vital after the summer of 2019, when two more major non-gas-fired generators will have retired.

Improvements to fuel accessibility will require investments in natural gas infrastructure (including the possibility of forward procurement of liquefied natural gas to ensure its availability during the winter months) or greater flexibility to switch to oil as a backup fuel. Ideally, this will be achieved through market incentives, but as a last resort, the ISO may have to retain some non-gas-fired power plants.

For more than a decade, the ISO has been grappling with the fuel-security issue. But now we’re also weighing options for managing an emerging complication—how to harmonize the region’s competitive marketplace with state environmental goals.

The wholesale markets are designed to reveal the most cost-effective set of resources to meet the demand for electricity. They have served the region very well over the past two decades, attracting billions in private investment and creating a competitive environment that has helped drive down wholesale prices, spur innovation, and create one of the most efficient generation fleets in the country. Nevertheless, the efficacy of these markets is vulnerable to the unintended consequences of long-term state contracts for clean-energy projects.

The states view long-term contracts as the most expeditious way to promote the development of clean-energy resources and the transmission investments needed to deliver that energy. Because clean-energy resources typically have higher development costs and New England’s wholesale markets do not price carbon, these resources are currently not competitive in the wholesale marketplace without some form of subsidy.

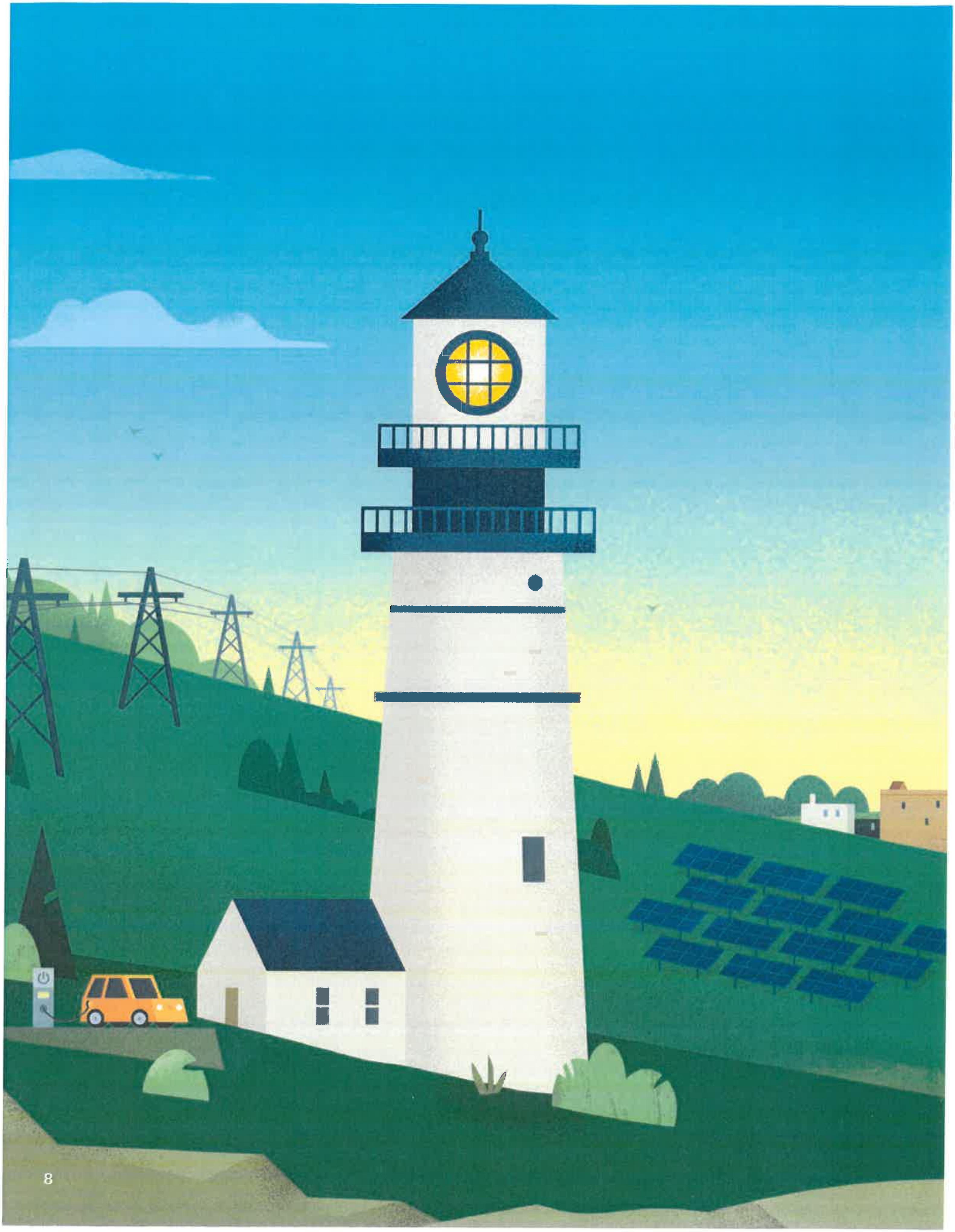
and grid-scale energy storage to allow for complete independence from fossil fuels."

Another perspective the region must also consider is the effects of these contracts on long-term reliability and the structure of the marketplace. As more renewable resources come on line, energy market prices will decrease significantly because of renewables' low fuel costs and state subsidies. As a result, other types of power resources will become even more dependent on revenues from the capacity market, which procures power resources to meet the region's future electricity needs. The participation of large quantities of state-subsidized renewables in the capacity market, however, will also undermine accurate capacity market prices—thereby accelerating the retirement of the very power plants that the region still needs to ensure a reliable electricity supply. Additionally, the capacity market will lose its ability to incentivize investment in, and retention of, efficient and innovative infrastructure and technologies, thereby forcing a return to long-term contracting for all resources.

This leads to a thorny market-design challenge: given that state policymakers are taking action to reduce emissions, how does the wholesale marketplace account for state-sponsored resources without compromising reliability and investment through the markets?

Many questions remain about how best to balance the region's two overarching policy objectives of securing reliability through competitive markets and meeting state carbon-reduction goals, as well as how to solve the pressing fuel-security issue. The ISO is applying its decades of expertise and firsthand experience to developing effective, efficient, and innovative solutions to these challenges in collaboration with our stakeholders. As the ISO commemorates its 20th year of service to New England and leadership in managing its highly reliable, cutting-edge grid, I look forward to working with our stakeholders with the confidence that, together, we will find answers to these questions.

Sincerely,



20 Years
of ISO New England

In just two decades, the ISO has helped New England revitalize its power system and lay the foundation for a cleaner energy future.

A New Era of Competition and Reliability

When you compare New England's electric power system of 20 years ago with today's power grid, the contrast is striking. For decades, the region's utilities operated as vertically integrated, regulated monopolies that generated, transmitted, and distributed electricity to retail customers at cost-of-service rates. Dissatisfied with these rates and a lack of investment in new infrastructure and more efficient, cost-effective technologies, the region began pursuing an alternative framework, one that would introduce competition into the industry.

After passage of the *Energy Policy Act of 1992*, the Federal Energy Regulatory Commission (FERC) created independent system operators and, in 1997, gave ISO New England responsibility for ensuring a reliable supply of electricity for the region and establishing and overseeing competitive wholesale markets for buying and selling electricity. Working closely with the New England states, electric power companies, and other regional stakeholders, the ISO helped lead the nation's most advanced effort at industry restructuring. A new competitive marketplace with open access to transmission lines created a level playing field for buyers and sellers of wholesale electricity. During this same period, five of the six New England states passed laws creating competitive retail electricity markets and ultimately divesting most of the utility-owned generation in the region. This transferred the risk in developing new power resources to investors and away from retail customers and created an incentive to build and run these plants as cost-effectively as possible.

ISO New England was designated a Regional Transmission Organization in 2005, with broader authority over development of the transmission system and greater independence to design fair and efficient wholesale markets. Today, the ISO continues to fulfill its historic mission of using competitive markets to secure a reliable supply of electricity for New England's households and businesses. Visit **www.iso-ne.com/history** to see the ISO timeline.

Markets Are Yielding Tangible Results

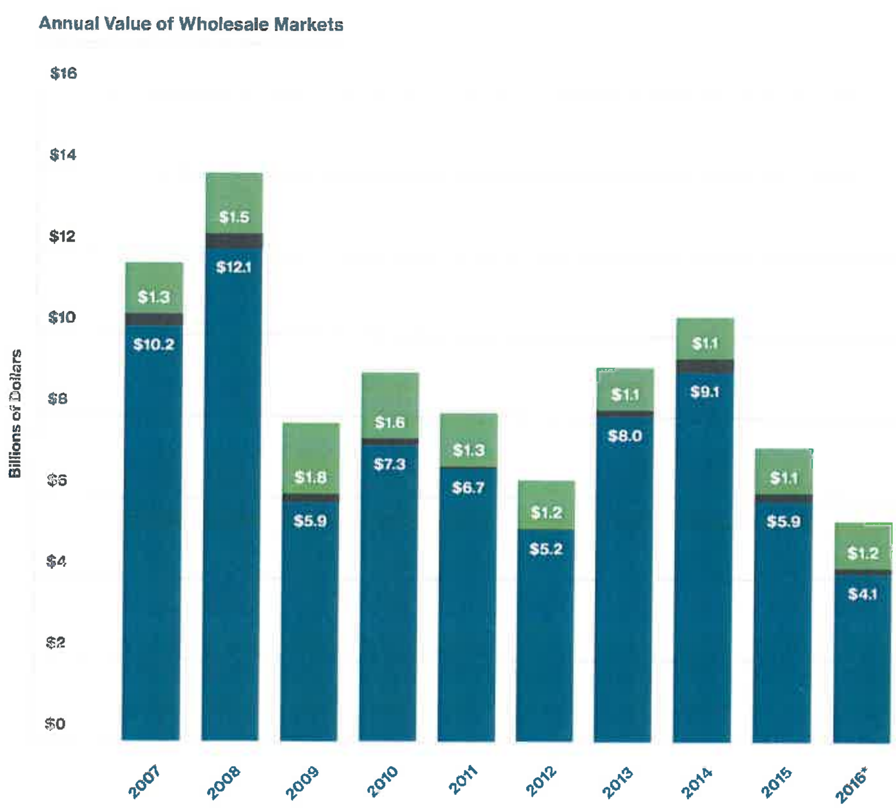
The open, transparent wholesale electricity marketplace designed and run by the ISO stimulates strong competition among over 400 buyers and sellers and has attracted billions of dollars in private investment in some of the most efficient, lowest-emitting power plants in the country. Markets select the lowest-priced power resources competing to produce electricity or provide other specialized services, compensating all suppliers equally, regardless of technology. Markets also provide the incentive for resources to offer prices for electricity as close as possible to their fuel and operating costs and to perform reliably. Competition drives private investment in energy production technologies that provide efficiencies and savings today, as well as in emerging technologies that may revolutionize energy production tomorrow. In addition, the ability of wholesale market prices to accurately reflect current conditions at specific locations serves as a signal to developers to invest in new power resources when and where they are most needed.

These characteristics of competitive markets have helped produce real benefits for New England:

- **Less air pollution**—The addition of over 13,000 megawatts (MW) of natural-gas-fired generation has been largely responsible for significant long-term reductions in **regional generator air emissions**, with nitrogen oxides (NO_x) falling by 68%, sulfur dioxide (SO_2) by 95%, and carbon dioxide (CO_2) by 24% between 2001 and 2015, as the region has largely shifted away from burning coal and oil.

Lowest Wholesale Prices in Over a Decade

The biggest component of the region's **wholesale electricity marketplace** is the energy market. Its value rises and falls due to changes in fuel costs for the region's generating fleet, as well as in consumer electricity demand. The region's robust transmission system also allows the most economic resources to operate.



*Preliminary values

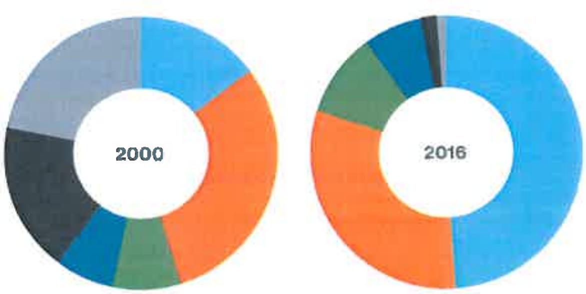
- **Lower wholesale energy costs**—The availability of low-cost natural gas from the nearby Marcellus Shale formation was the main driver of a 44% decrease in the average price of New England's wholesale electricity between 2004 (the first full year of the redesigned energy market) and 2016. In 2016, the combination of mild weather and extremely low natural gas prices resulted in the lowest average annual energy market prices since 2003.

- **Enough power resources to meet the region's needs**—The **Forward Capacity Market** (FCM) has procured about 30,000 MW of generating capacity, 800 MW of active demand response, and 2,000 MW of energy efficiency (EE) to meet New England's needs in 2017 and replace retiring generators. (The capacity market compensates resources that commit to being available in three years' time to meet the region's projected energy needs.) New projects that cleared in the FCM's 2016 auction will be located in the high electricity demand areas of Connecticut, Rhode Island, and Southeast Massachusetts. Generator availability, accounting for planned and unplanned outages, has also increased to 88% in 2016 from 75% in 1997.

A Shift to Cleaner, More Efficient Fuels

The markets, in combination with a boom in nearby lower-cost shale gas, have attracted highly efficient, flexible natural-gas-fired generators. These have almost entirely displaced higher-emitting oil and coal units in producing electricity regionally.

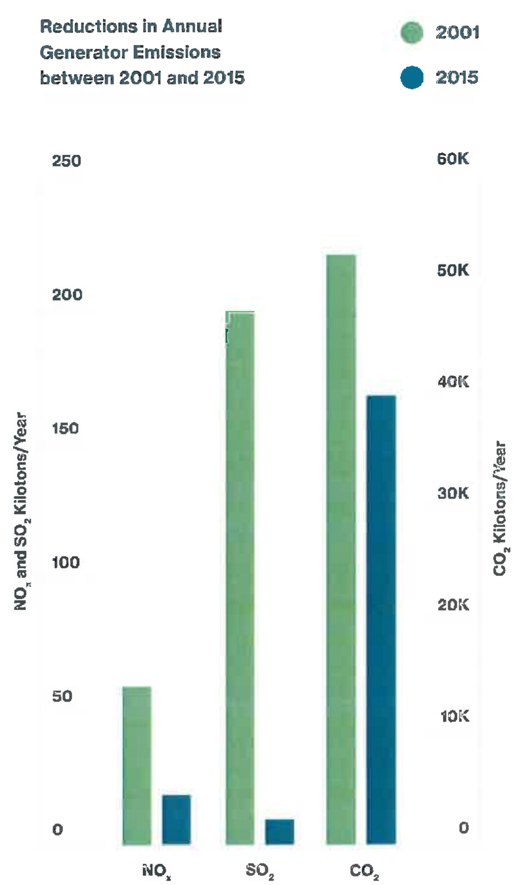
Annual Fuel Mix



	2000	2016
Natural Gas	15%	49%
Nuclear	31%	31%
Renewables	8%	10%
Hydro	7%	7%
Coal	18%	2%
Oil	22%	1%

A Dramatic Drops in Emissions

The shifting fuel mix has led to significant decreases in air emissions from the region's generators.



Improved Transmission Has Led to Better Reliability and Pricing

Before industry restructuring, New England saw little investment in transmission infrastructure, which resulted in congestion—system constraints that prevent the least-cost electricity from reaching certain locations and can threaten reliability. In 2006, the US Department of Energy labeled New England a Congestion Area of Concern.

Over the last 20 years, the ISO's continuous study and analysis of the transmission system has helped guide cooperative regional investment to fix weak spots and bottlenecks on the system. After years of strong investment, New England now has a more reliable and flexible power system, costly congestion has been virtually eliminated, and the region is no longer a Congestion Area of Concern. (See the *Regional System Plan* [RSP], ISO New England's 10-year planning report, at **www.iso-ne.com/rsp**, and learn about the region's new competitive process for eligible projects at **www.iso-ne.com/competitive-transmission**.) The **transmission system today** includes about 9,000 miles of high-voltage power lines and related facilities spanning the six states, as well as 13 interconnections with neighboring power systems that enable the import of competitive and emergency supplies from New York and eastern Canada. The region met 17% of its energy needs with imported electricity in 2016.

Strong Regional Transmission Investment Has Created a More Reliable, Efficient System

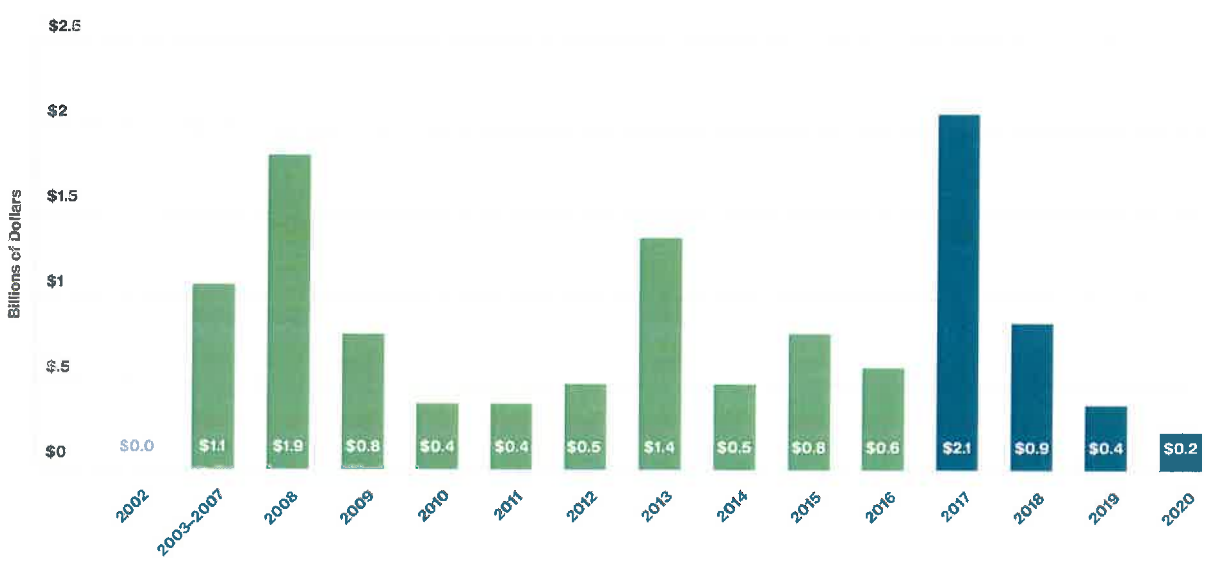
As of the October 2016 update to the Regional System Plan Project List, 690 project components had been placed in service and an additional 153 projects were anticipated over the next 10 years to ensure that electricity continues to move reliably and efficiently across the region. The estimated future investment shown here includes projects that are under construction, planned, and proposed.

Cumulative Investment through October 2016: $8.02 Billion

Estimated Future Investment through 2020: $4.07 Billion

Source: ***ISO New England Regional System Plan Transmission Project Listing*** (October 2016)

Transmission Investment in New England to Maintain Reliability



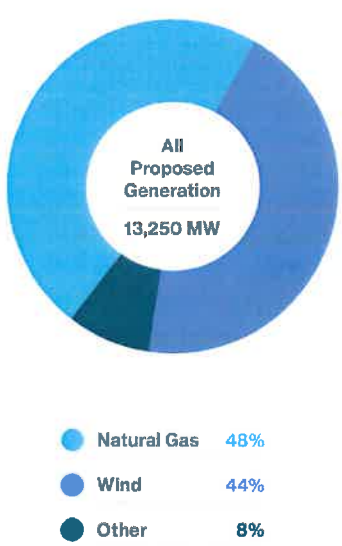
Yet to be determined is whether transmission projects needed to enable the interconnection of additional wind power in northern New England or hydro power from Canada will proceed. Elective transmission upgrades (ETUs)—transmission lines funded by private developers—may play a role in accomplishing this. As of January 2017, 17 ETUs had been proposed in the ISO Generator Interconnection Queue, totaling about 10,500 MW of potential transfer capability. Because of the volume of study requests, the ISO has streamlined the ETU grid-interconnection process.

The Region Is Attracting New Generation, but Transmission Improvements Are Needed to Interconnect More Wind Power

Higher market prices signal an investment opportunity for new, more efficient power resources to replace generators that are closing down and to displace those that are inefficient or expensive. The ISO is slated to study almost 90 grid-interconnection requests from proposed new generators, though many may not ultimately be built. About half this new capacity is proposed to run on natural gas. In addition, requests include over 5,800 MW of wind power, over 700 MW of grid-connected solar power, and almost 80 MW of grid-connected battery storage. Because of the large distances from some of the proposed onshore wind power projects to the existing grid, major transmission system upgrades will be needed to deliver more of this power to far-away consumers. Proposed offshore wind projects closer to New England load centers may require fewer upgrades to the existing grid, but building wind turbines offshore is typically more costly than placing them on land.

Source: *ISO Generator Interconnection Queue*
(January 2017; FERC jurisdictional proposals only)

Wind Project Proposals in New England



Transmission Project Costs Pay Off for the Region

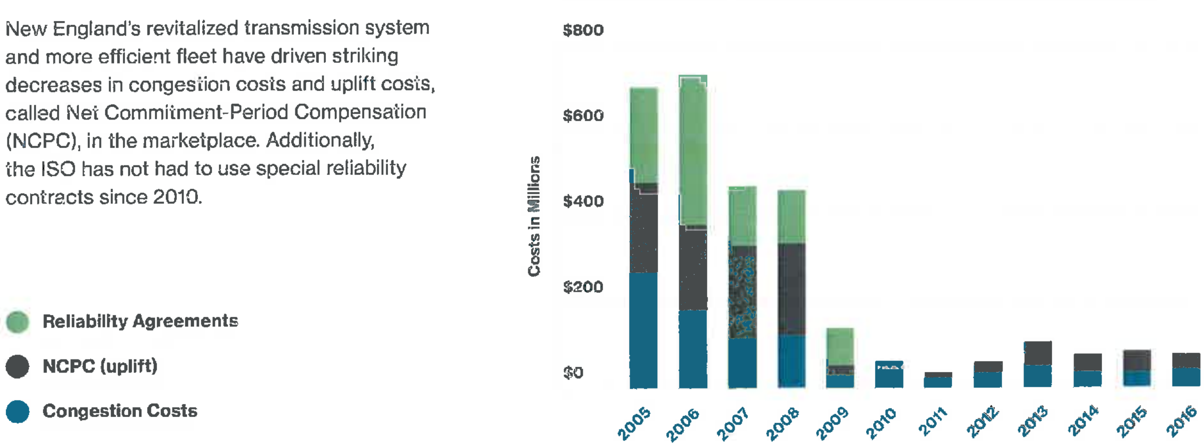
Because the electric grid is so tightly networked, each state shares in the benefits—and costs—of reliability upgrades to this transmission system. New England's electricity consumers, who ultimately pay project costs, receive many benefits from this **investment in the regional transmission system**:

- **Less risk of expensive, dangerous blackouts**—The 2003 Northeast Blackout, for example, affected 50 million people in the Midwest and in the northeastern US and Canada, claiming three lives and an estimated $4.5 to $10 billion in losses. New England was largely spared during the blackout but subsequently took action to strengthen weak areas of the region's transmission system. Today, a robust transmission infrastructure, along with a strong fleet of power resources, rigorous system operator training, and strict adherence to industry reliability requirements, can help the ISO manage system disturbances.
- **Less air pollution**—Improving system weak spots and eliminating transmission bottlenecks has allowed new, efficient, low-emitting generators, such as those running on natural gas, to interconnect to the grid, run more often, and displace older, less efficient resources.
- **Lower wholesale energy costs**—Enabling the integration of these resources has also helped drive down wholesale electricity prices because of the relatively low cost of natural gas. Congestion costs are also extremely low today: in 2015, average energy-market prices at the wholesale Hub and across the six states differed by just 1–1.5%. Additionally, payments to resources providing operating-reserve support in transmission-constrained areas have markedly declined, and the region has been able to eliminate costly reliability contracts needed in the past to keep older, inefficient resources from retiring to ensure reliability.
- **Positioning for a greener, hybrid grid**—A strong, state-of-the-art transmission system is the "backbone" needed to support the connection of more renewable energy and the **transition to the smart grid**, which will open the door for more effective use of distributed energy resources.

Improvements Have Lowered Energy Costs

New England's revitalized transmission system and more efficient fleet have driven striking decreases in congestion costs and uplift costs, called Net Commitment-Period Compensation (NCPC), in the marketplace. Additionally, the ISO has not had to use special reliability contracts since 2010.

New England Costs for Congestion, Uplift, and Reliability Agreements



Ensuring Reliability in the Next 20 Years —and Beyond

The electricity industry continues to evolve, and so does the ISO. Through cutting-edge initiatives and strong regional collaboration, we're shaping the modern, high-performing power system New England relies on for safety, comfort, and prosperity.

The Shift toward a Hybrid Grid and Carbon-Free Society

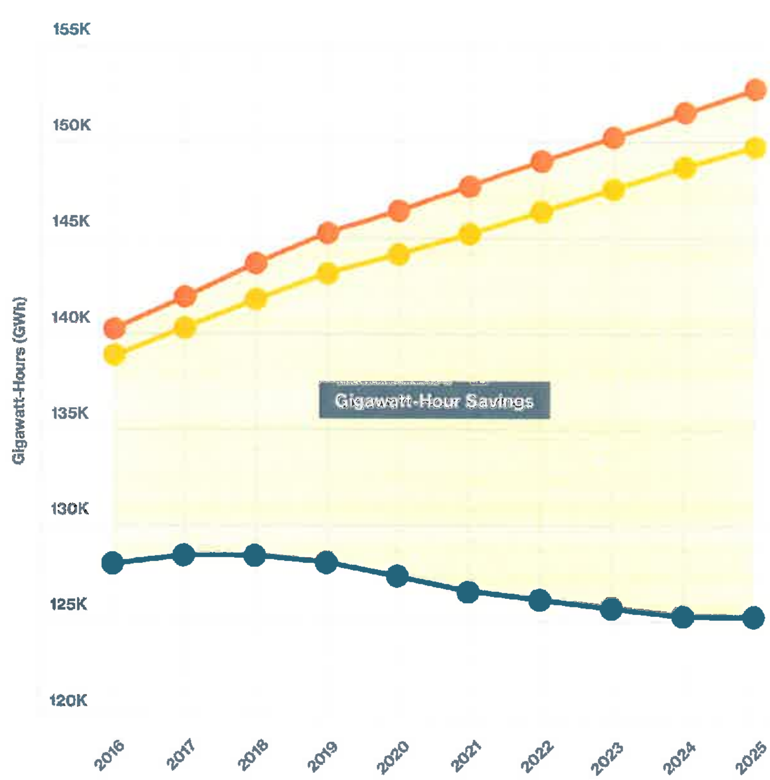
New England's traditional power system is rapidly transforming into a more complex, less predictable hybrid grid where electricity needs are met with large generators and other power resources connected to the regional transmission system, in combination with thousands of small resources connected "behind the meter" directly to retail customer sites or local distribution utilities. In addition to significant amounts of carbon-free renewable energy, the regional generation fleet will need to include fast, flexible power plants ready to jump in and balance the variable output from wind and solar resources; these will likely be natural-gas-fired generators in the near term because of their ability to turn on and off quickly. At the local level, rooftop solar systems and battery storage—along with energy-efficiency measures, electric vehicles, and smart meters—are changing how much electricity people draw from the regional power system, when they draw it, and what they add back to the grid.

Energy-Efficiency Measures and Solar Power Are Flattening Annual Energy Use and Slowing Peak Demand Growth

With approximately $1 billion being invested annually, the New England states are national leaders in implementing EE measures, such as the use of more efficient lighting, appliances, cooling, and building operation. Over the next decade, EE and behind-the-meter solar reverse the growth in overall electricity demand to -0.2% and slow the growth in summer peak demand to 0.3%.

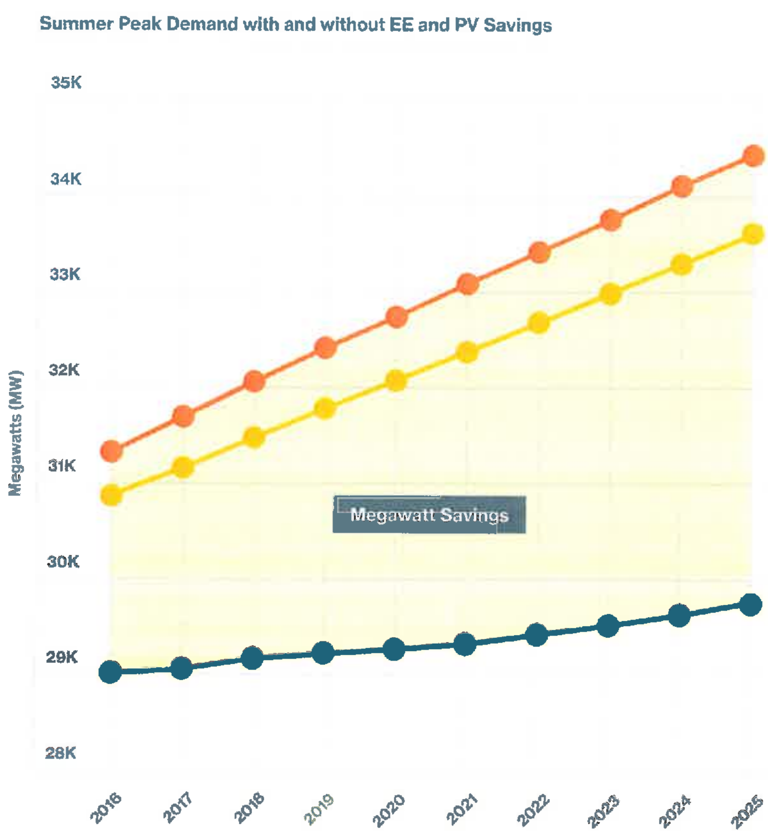
Source: ***Final ISO New England Energy-Efficiency Forecast 2020-2025*** and ***Final 2016 Solar PV Forecast*** (May 2016)

Annual Energy Use with and without EE and PV Savings



ISO Innovation Is Paving the Way

To fulfill our responsibilities to New England in light of this transformation, we've made major innovations to how we operate the grid and plan for the future, to our IT systems, and to the marketplace we design and administer. For example, we're leading the industry's use of high-speed cloud computing to analyze vast quantities of smart grid data. To help manage the fluctuating output of wind and solar power resources, we've developed a highly accurate hourly wind forecast for the region and each individual wind farm, participated in several national studies to develop accurate solar forecasts, and prototyped a better forecast for solar power. ISO staff also developed the first, multistate forecast in the nation on the growth of energy-efficiency measures, as well as the first, multistate forecast for behind-the-meter solar installations. Learn more at **www.iso-ne.com/smart-grid**.



Gross Load

The gross load forecast (projected regional energy use)

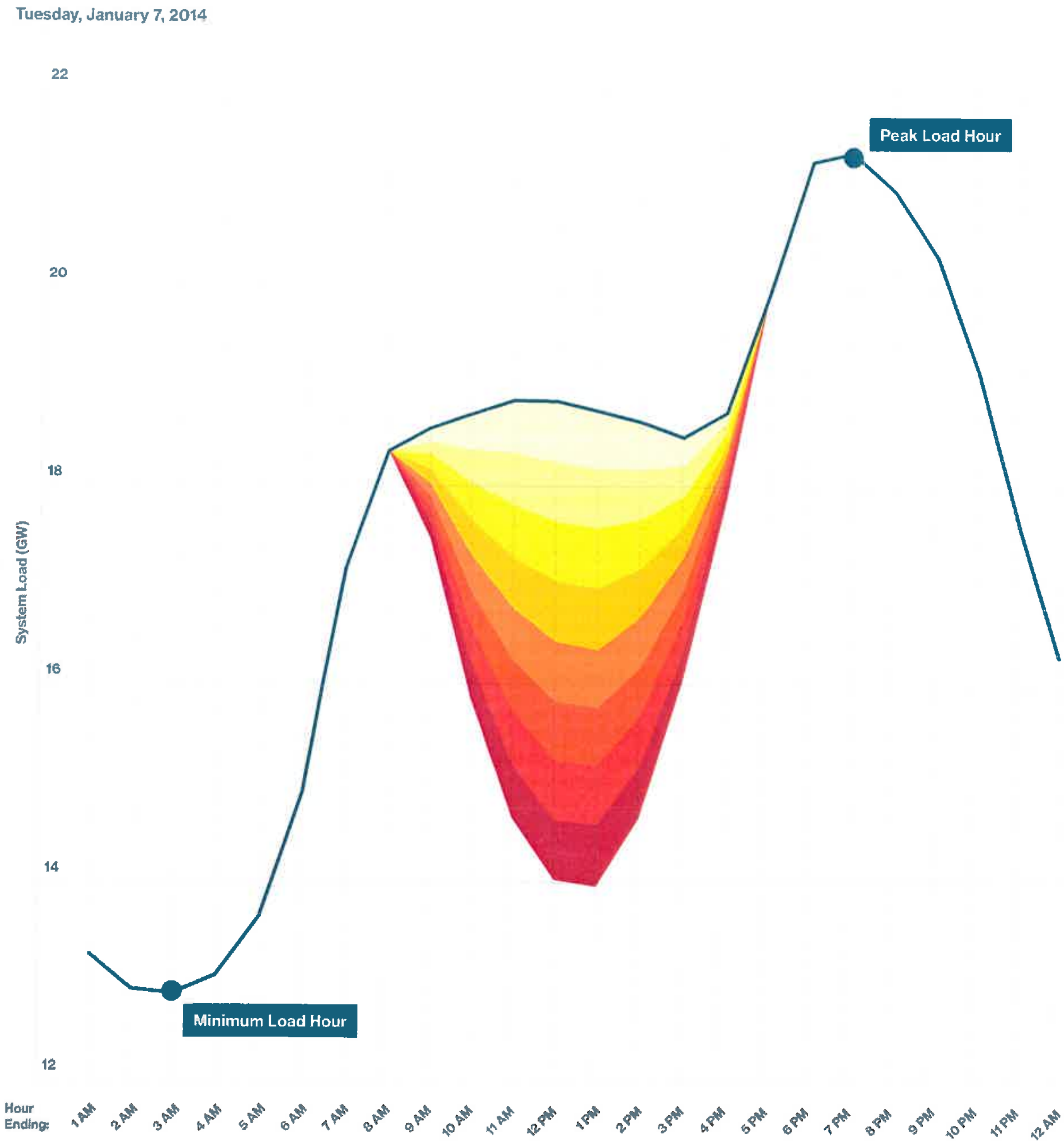
Minus PV

The gross load forecast minus forecasted behind the meter (BTM) solar photovoltaic (PV) resources

Minus PV, EE

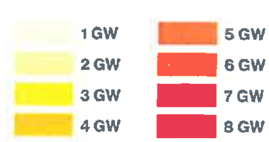
The gross load forecast minus forecasted BTM PV, minus energy-efficiency (EE) resources in the Forward Capacity Market (FCM) 2016–2019 and forecasted EE 2020–2025

Note: Summer peak demand is based on the "90/10" forecast, which accounts for the possibility of extreme summer weather, such as an extended heat wave of about 94 °F.



Accurately Forecasting the Load-Reducing Effects of Solar Power Is Increasingly Important

Because most **solar power in New England** is connected behind the meter, it serves to reduce the amount of electricity drawn from the regional grid. This load profile simulates the impact that growing amounts of solar power will have during winter – and shows how it can't serve winter peak demand. The steepening ramp to peak load hour also illustrates how flexible, fast-responding power resources will become increasingly important for serving the region's needs.



Several **market-based changes** are also helping pave the way for future grid transformation:

- In 2016, we **incorporated wind resources and intermittent hydro resources into real-time dispatch for the first time**, enabling them to set real-time prices. This project used a pioneering methodology the ISO developed to efficiently account for the variable "fuels" powering these resources.
- We've opened the door for new energy-storage technologies, such as batteries and flywheels, to **compete in the Regulation Market** by introducing an "energy-neutral" dispatch signal to integrate these resources into grid operations.
- Changes in 2018 will make it easier for storage devices and similar technologies that both consume and inject energy to participate as dispatchable resources in the energy market.
- We've been a leader in **integrating demand-response resources** into the wholesale electricity marketplace and expect to complete full integration in 2018.

Facilitating Regional Collaboration to Solve Ongoing and Future Challenges

A fundamental part of ISO New England's mission is to be an advocate for reliability to ensure that the region has the electricity it needs when it needs it. A reliable regional power system is essential to New England today and will remain critical for decades to come, serving households and businesses that don't generate their own electricity and acting as backup power for those that do.

Many of the changes noted in this report are the result of strong **collaboration with our regional stakeholders**. Continued cooperation will be vital to solve for two of the most pressing **challenges to reliability**, as outlined in the next two chapters.

Challenge: How to Secure Adequate Fuel for Natural-Gas-Fired Generation

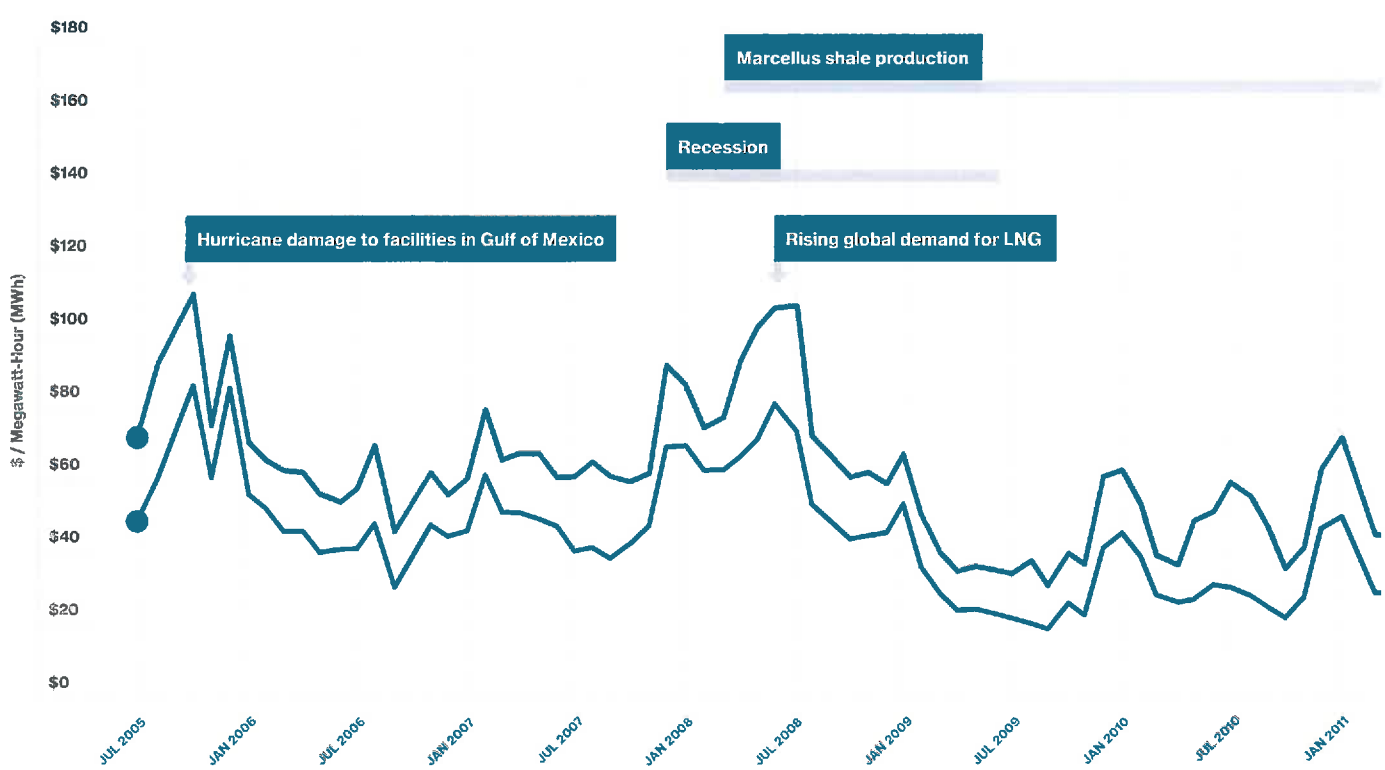
Timely solutions are imperative for this major challenge to the regional power system. Reliability, rising winter air emissions, and electricity price volatility are all at stake.

Reliable Electricity in New England Is Tightly Linked to Natural Gas

A fundamental part of the ISO's job is to keep the amount of electricity that power resources are supplying to the grid in near-perfect balance with the amount of electricity consumers are using. The region's highly efficient **natural-gas-fired generation resources** are currently the biggest contributor for achieving that balance. Natural gas:

- Fuels nearly half the region's electricity annually—49% in 2016
- Is the primary fuel source for over 40% of regional capacity and an alternate fuel source for over 10% more
- Represents almost half the currently proposed new generation projects in the region
- Will be needed to balance wind and solar resources until other flexible resources (such as grid-scale energy storage) are economical and widespread

Natural Gas and Wholesale Electricity Prices



Natural Gas Pipeline Constraints Limit Fuel for Generators during Cold Snaps

Traditionally, the natural gas pipelines that deliver low-cost shale gas into the region have been built and sized to serve customers of gas utilities—not specifically to serve electricity generators. Gas utilities commit to the long-term contracts required for incentivizing pipeline development. Generators, on the other hand, typically forego these premium contracts, instead arranging for fuel only as needed and relying on unused pipeline capacity for delivery. Because generators have no guarantee of when or how long they'll be called

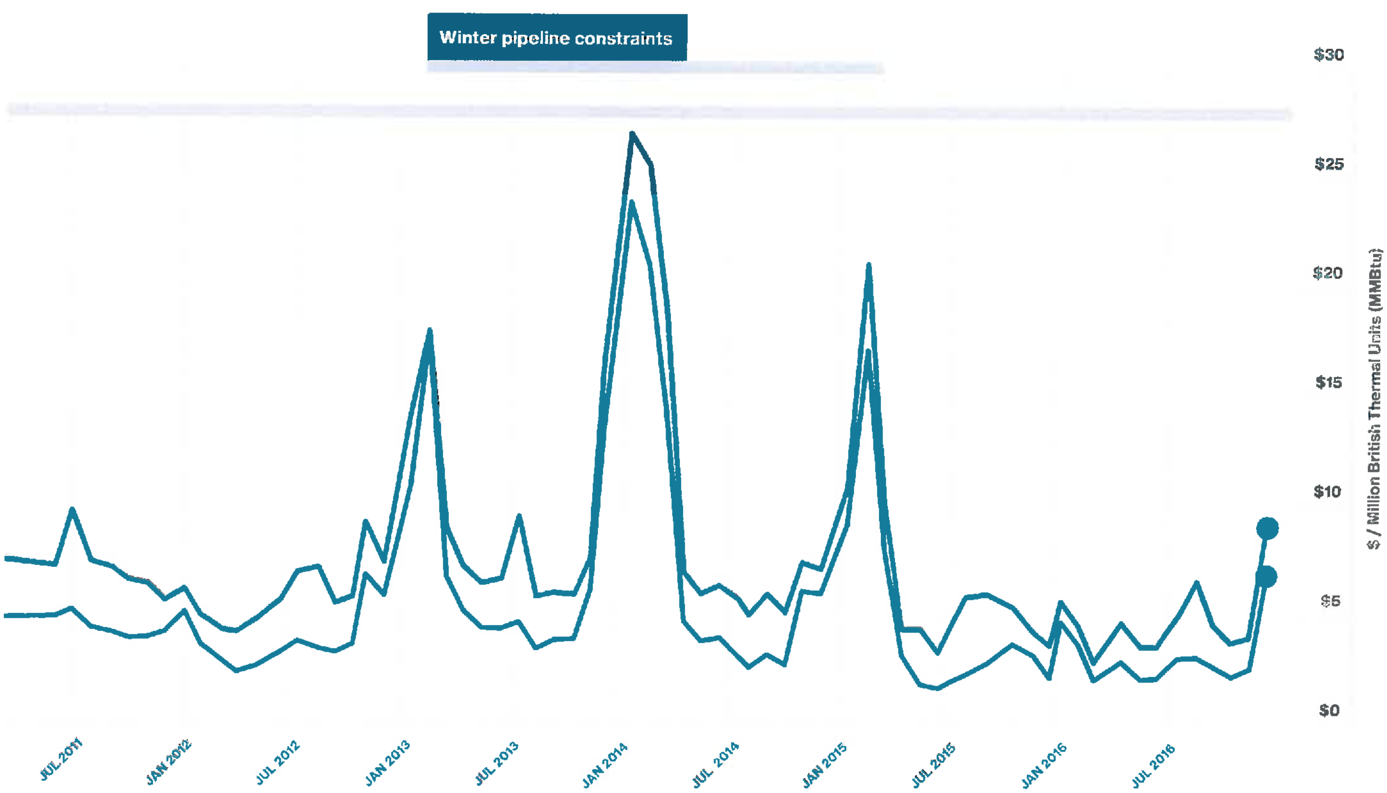
Natural Gas Pipeline Constraints Can Lead to Price Volatility

Natural-gas-fired generators set the **price for wholesale electricity** most of the time. When natural gas prices spike due to pipeline constraints, wholesale electricity prices spike, too. In contrast, when the region's gas-fired generators have unconstrained access to natural gas, wholesale electricity prices tend to be low and competitive nationally.

Underlying natural gas data furnished by ICE Global markets in clear view

Natural Gas Prices at Algonquin City Gate

Wholesale Electricity Prices in Real-Time Energy Market



to run—and there's no practical way to store excess natural gas or electricity—this "just-in-time" strategy helps natural-gas-fired generators keep their costs as low as possible to maintain competitiveness in the wholesale electricity markets. While that works for most of the year, on cold days, the pipelines are running at or near maximum capacity solely to meet heating demand. During several past winters, this situation has severely limited the delivery of fuel for much of the region's generating capacity, which, in turn, threatened the reliable supply of electricity and drove up wholesale electricity prices and air emissions.

Some pipeline capacity was added in 2016 and more is expected in 2017 to serve increased demand from retail gas customers. Over the next few winters, some of this capacity will likely be available for generators on the coldest days, helping to lessen fuel supply concerns and associated volatility in wholesale electricity prices. However, eventually this extra capacity will likely be used for heating as gas utilities sign up more customers. To compound matters, most of the benefit from additional fuel available to generators on the coldest days will be canceled out as new natural-gas-fired generators fill the void of retiring non-gas-fired power plants. In other words, though the pipeline "pie" may be getting bigger, there will be more mouths to feed. When it comes to the power system's ability to meet electricity demand on the coldest days, the results may be a wash.

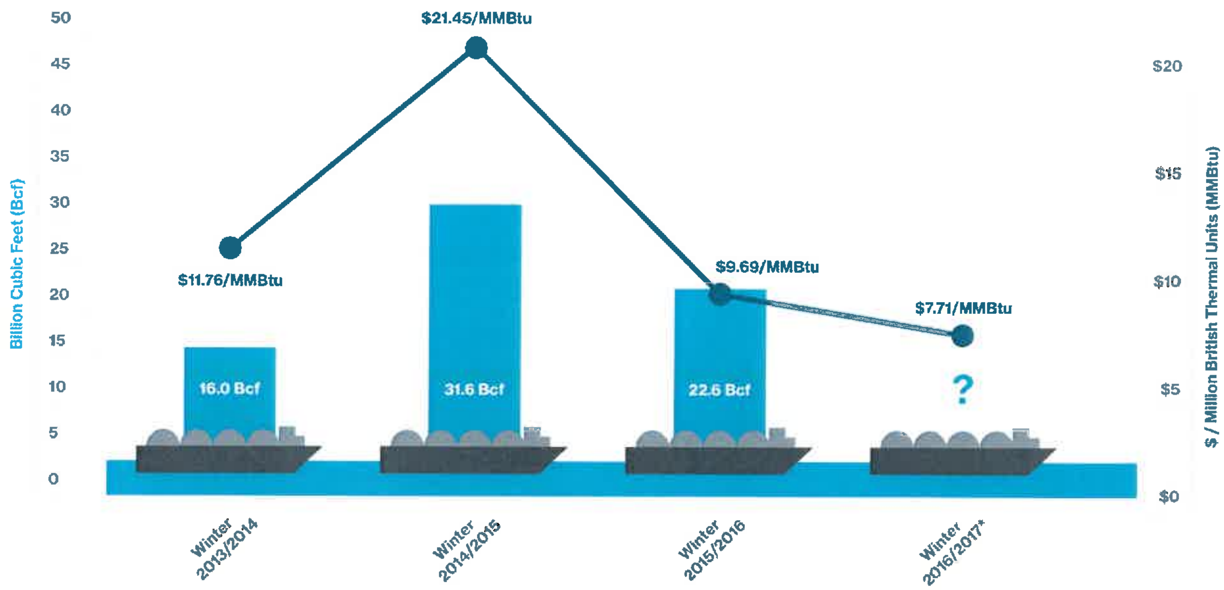
Will Imported Liquefied Natural Gas (LNG) Fill the Gap?

The least expensive option that the region's natural-gas-fired generators might take to improve performance is to invest in dual-fuel technology that allows them to switch to oil when pipeline gas becomes too expensive or unavailable. But state restrictions on air emissions may limit this option, thus requiring more natural gas plants to turn to LNG in winter when pipeline gas is unavailable or its price spikes.

However, several factors can impede generators' access to LNG when it's most needed. First, LNG is a global commodity that's imported to New England by ocean tanker, so it must be contracted for months in advance—an option most generators elect not to pursue. Second, the arrivals of any spot LNG cargoes depend on global prices and vary from year to year; they also supply the entire Northeast and beyond—not just New England generators. Third, severe weather could prevent the timely arrival of ships.

Over recent years, the ISO's **Winter Reliability Program** has helped incentivize a small number of generators to secure contracts for winter deliveries of LNG. These types of contracts, as well as the building of on-site LNG storage, are among the options generators could invest in to satisfy upcoming performance requirements in the capacity market.

LNG Tanker Deliveries to New England During Winter and Natural Gas Futures-Market Prices



LNG Deliveries Hinge on a Global Market and Winter Weather Predictions

The amount of LNG coming into the region varies from year to year. When prices are high for natural gas delivery into New England, more LNG tankers are attracted to the region. Expectations of a severe winter can cause prices to increase – and futures-market prices typically illustrate this effect. But if a winter turns out to be more frigid than the futures market anticipated, the region may end up with an inadequate supply of LNG.

Algonquin Natural Gas Futures Prices as of Previous October 1

Winter LNG-Sourced Deliveries to New England Interstate Pipelines

**The preliminary total through mid-January 2017 was 6.4 Bcf; more deliveries are expected before winter's end. See www.iso-ne.com for updated data.*

Sources: *Winter 2016-17 Energy Market Assessment*, FERC; NatGas Analyst Tool by Genscape, a part of DMG Information (DMGI), www.genscape.com

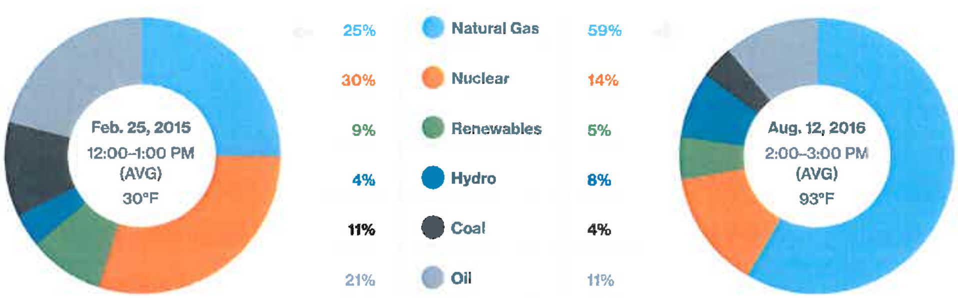
Non-Gas-Fired Generation Options Are Dwindling

Resources powered by oil, coal, and nuclear energy have been critical for keeping the lights on during recent winters, but these units have begun to close, citing profitability and other factors. About 4,200 MW—an amount equal to almost 15% of the region's current generating capacity—will have shut down between 2012 and 2020 and is being replaced primarily by new natural-gas-fired plants. The upcoming closures of just two of those resources—Brayton Point Station in May 2017 and Pilgrim Nuclear Power Station by May 2019—will remove 2,200 MW of non-gas-fired capacity. Over 5,500 MW of additional oil and coal capacity are at risk for retirement in coming years, and uncertainty surrounds the future of 3,300 MW from the region's remaining nuclear plants.

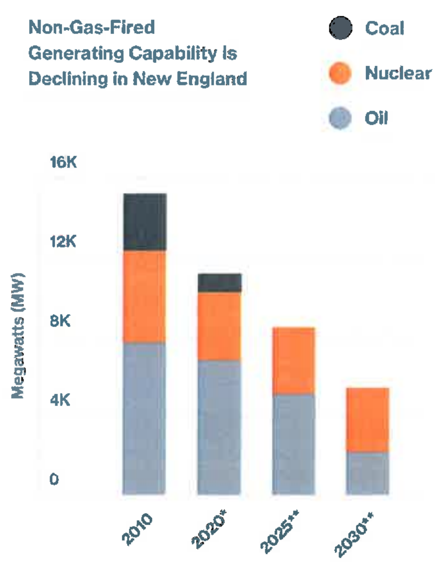
Major Generator Retirements Limit the ISO's Options for Meeting Winter and Peak Demand

Nuclear power typically provides around 30% of the region's energy. Coal- and oil-fired resources, despite providing only about 3% of the region's electricity last year, can also make valuable contributions on the coldest days of winter, as well as on the hottest days of summer when demand is very high or major resources are unavailable. For example, on the 2016 summer peak day shown below, a nuclear generator was unexpectedly off line and coal and oil filled the gap. Within a decade, though, the region may have little to no generating capacity left fueled by coal and oil, and is also at risk of losing more nuclear generators.

Non-Gas-Fired Resources Are Critical During Winter and Peak Summer Days



Non-Gas-Fired Generating Capability Is Declining in New England



* Includes major planned retirements

** Hypothetical values assuming the loss of over 5,500 MW from generators identified as being at-risk of retirement due to plant age and infrequent operation

Sources: *Forecast Report of Capacity, Energy, Loads, and Transmission* (2010, 2016); *Status of Non-Price Retirement Requests and Retirement De-List Bids* (August 2016); *2016 Economic Studies Phase I Assumptions*, ISO-NE (2016)

Several Major Non-Gas-Fired Generators Plan to Close or Are at Risk of Retiring

Skating By on the Coldest Days

With over 35,000 MW of regional generating capability, demand resources, and imports, meeting New England's winter peak demand of roughly 21,000 MW, plus a reserve margin of about 2,600 MW, should be a routine "day at the office" for ISO system operations. Despite sufficient capacity and some relatively mild winters, though, ISO system operators have actually managed very tight operating conditions over recent years. To keep the power flowing, the ISO has relied heavily on non-gas-fired generators and had to **follow procedures** several times when energy from available resources was insufficient (i.e., *ISO Operating Procedure No. 4: Action During a Capacity Deficiency*). If a "perfect storm" of problems were to occur, ISO system operators could be forced to use stronger measures, such as asking the public to conserve electricity or, in extreme cases, ordering controlled power outages. This risk increases after the upcoming generator retirements. Among the possible events the ISO has to be ready for during extreme temperatures: fuel constraints that can sideline thousands of megawatts of natural-gas-fired generation; mechanical problems for some of the region's aging non-gas-fired generators; reduced imports from neighboring grids dealing with the same weather; and delays of oil and LNG deliveries.

If a "perfect storm" of problems were to occur, ISO system operators could be forced to use stronger measures ... in extreme cases, ordering controlled power outages.

Will Adding More Renewables Help During Winter?

Wind and solar resources can offset some natural gas use, but their help is limited by still-low levels of regional installation. Additionally, wind speeds are variable and can drop during extreme cold snaps, paradoxically creating a need for natural-gas-fired generators that can ramp up and down quickly to balance fluctuations in supply or demand and maintain continuity of electricity supply. Solar energy, meanwhile, isn't dispatchable by the ISO and doesn't help meet peak winter demand, which happens after the sun has set. Moreover, winter conditions, with snowfall and fewer daylight hours, also dampen solar output. Extreme cold could also reduce imported Canadian hydropower through proposed new long-distance transmission lines because Canada is a winter-peaking system and may need the power itself.

The ISO's Efforts Have Mitigated the Fuel-Security Risk but May Not Solve the Problem

While the ISO doesn't have the authority to require generators to make long-term investments in fuel supplies, we have been developing tactics for the past six years to mitigate the fuel-security risk, such as:

- Developing new situational awareness and forecasting tools for our system operators to confirm fuel availability for natural-gas-fired units
- Improving communication and coordination with interstate pipeline operators
- Implementing **Winter Reliability Programs** that pay demand-response resources to be available and generators to boost winter fuel inventories of oil and LNG or to invest in dual-fuel technology (the ability to switch between different fuels, typically natural gas and oil)
- Fine-tuning the energy markets to strengthen resource performance
- Instituting **"pay for performance" (PFP) enhancements** that, starting in 2018, will reward resources that make investments to successfully boost performance during periods of system stress, such as by ensuring adequate fuel, while resources that don't perform will forfeit capacity payments

While these efforts help, they are unlikely to result in a timely "fix": PFP incentives (i.e., the rate for PFP payment or forfeiture) will ramp up only gradually through 2024. Additionally, many states' increasingly stringent air emission limitations may prevent natural-gas-fired generators from installing cost-effective oil-fired backup fuel systems. As a result, the region's winter reliability concerns will continue until generators decide to sign contracts for LNG—or, ultimately, greater natural gas pipeline capacity.

Without timely investment to expand natural gas or LNG infrastructure, the region should expect significant energy market price volatility when the gas pipelines are constrained.

The Region May Face Expensive, Higher-Polluting Options in the Coming Years

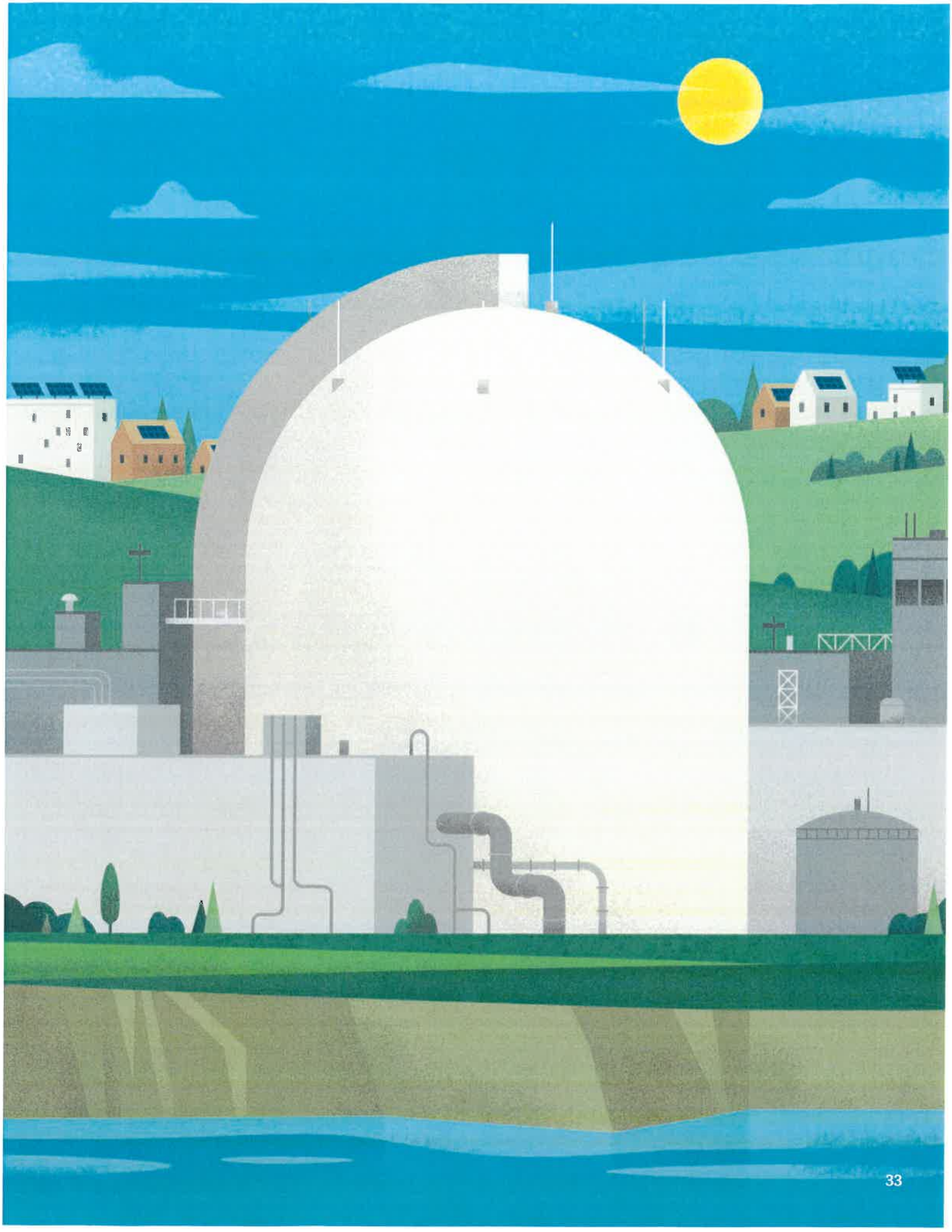
Without timely investment to expand natural gas or LNG infrastructure, the region should expect significant energy market price volatility when the gas pipelines are constrained. Plus, the region may soon be forced to take stronger—and likely costly—steps. The first step will be to further strengthen market incentives for generators to contract for fuel. As a last resort, the ISO may be forced into retaining some non-gas-fired generators that may be older, expensive, and higher-emitting—a strategy that runs counter to the states' ambitious carbon-reduction goals.

Other emerging factors are also likely to push the ISO to rely more on higher-emitting, less efficient resources to meet regional electricity demand and will add to operational complexity during winter:

- Siting challenges are causing delays in building some of the region's new power resources, particularly those running on natural gas. New transmission lines needed to maintain reliability, as well as elective transmission projects that can connect to clean-energy resources, are also often met with opposition.
- Some states are considering tightening emission limits for all generators—even state-of-the-art units running on relatively low-emitting natural gas. This could force the ISO to run higher-emitting generators in other parts of the region.
- Any additional closures of regional nuclear facilities will remove major sources of zero-emission energy for New England.

Challenge: How to Balance Competitive Markets and State Environmental Policies

State efforts to promote clean-energy resources and cut carbon emissions have long-term implications for the wholesale electricity marketplace's ability to secure reliable sources of electricity for New England. New market mechanisms are being sought to create a bridge between reliability needs and state environmental goals.



State Policies Are Driving the Growth of Clean-Energy Resources

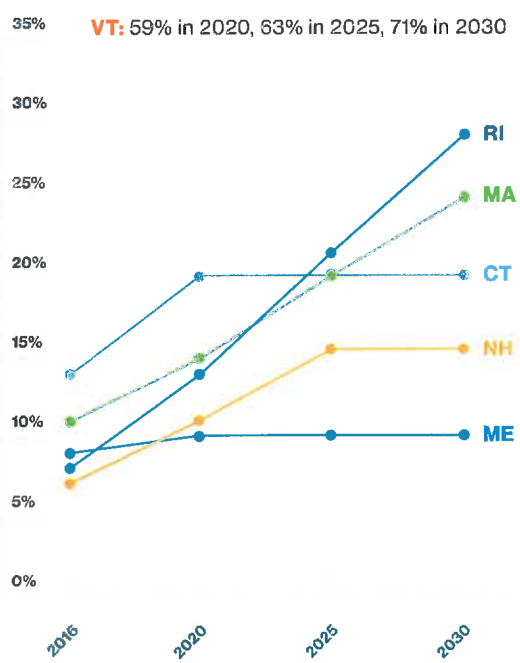
Even with low to no fuel costs, most **renewable resources** are still relatively expensive to build and connect to the grid, so they aren't competitive in the wholesale marketplace. Federal and New England state efforts to cut carbon emissions—by using emission limits, the mandated use of green power, and tax credits and incentives—are spurring growth in these resources. The New England states are also pursuing long-term contracts for clean-energy and energy-storage projects. While these out-of-market revenues are succeeding in attracting such projects, they're also having an impact on the traditional resource types needed to meet the region's electricity needs, balance intermittent renewable generation, and provide the grid-stability services that renewables don't.

The States Have Set Aggressive Goals for Increasing Renewable Energy

State Renewable Portfolio Standards require electricity suppliers to provide customers with increasing percentages of renewable energy. Vermont's standard recognizes new and existing renewable energy and is unique in classifying large-scale hydropower as renewable. The New England states are also promoting greenhouse gas (GHG) reductions on a state-by-state basis and at the regional level, through a combination of legislative mandates (e.g., CT, MA, and RI) and aspirational goals (e.g., ME, NH, VT, and NEG-ECP).

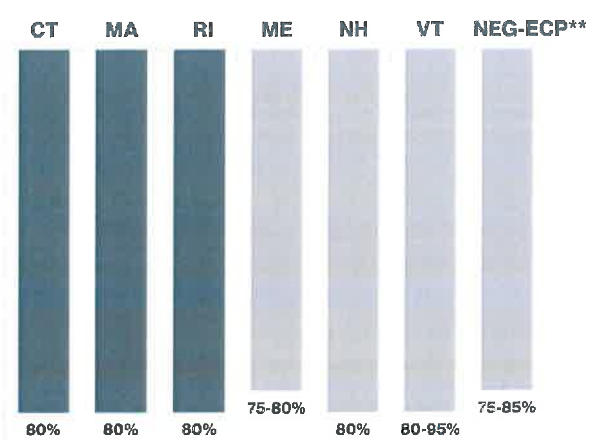
State Renewable Portfolio Standards Are Rising

Class I or new renewable energy resources (%)



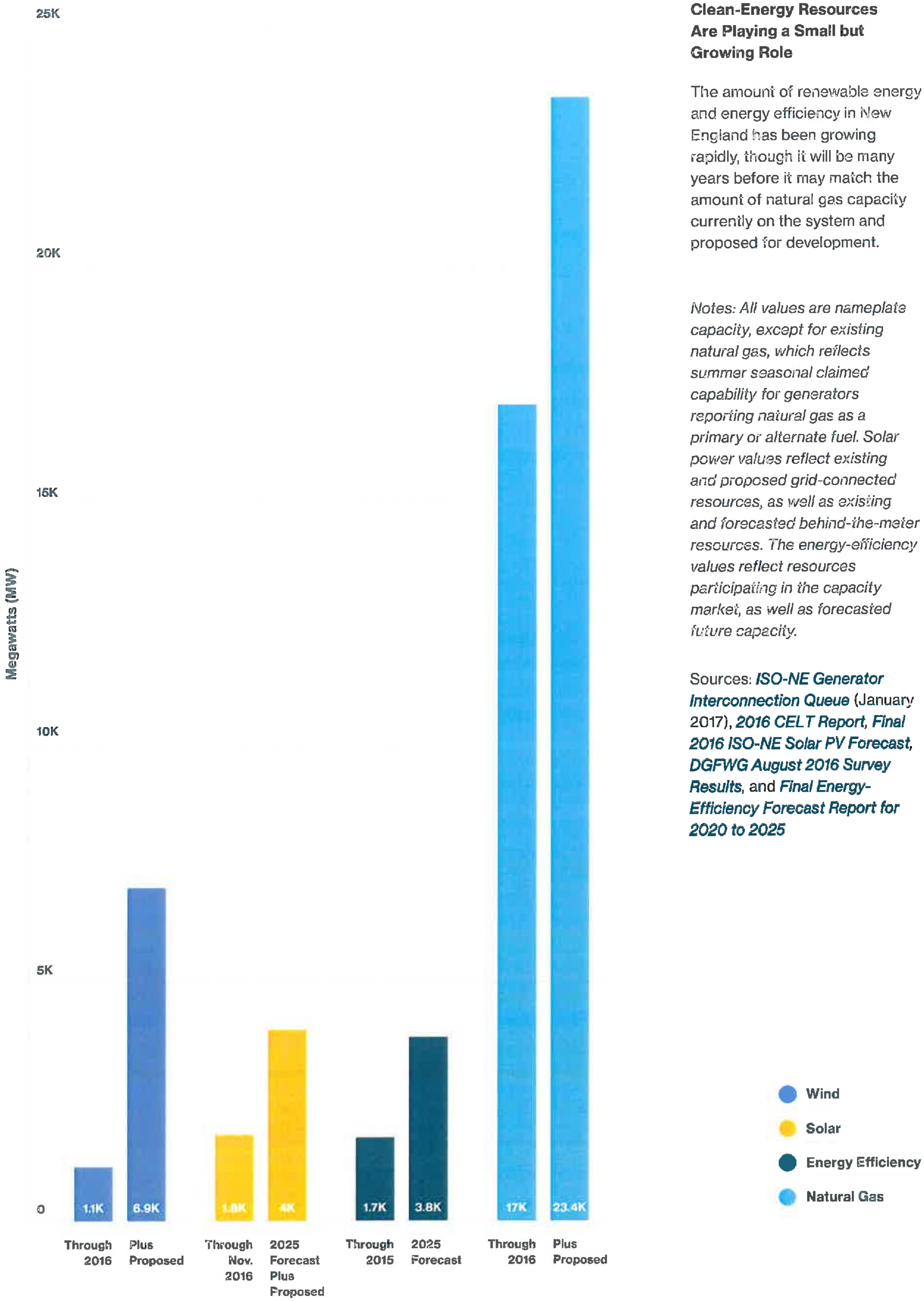
State Goals Seek Deep Reductions in CO_2 Emissions

Percentage reduction in greenhouse gas emissions below 1990 levels by 2050*



*Some states have different baseline and target years

**New England Governors and Eastern Canadian Premiers (NEG-ECP)



Clean-Energy Resources Are Playing a Small but Growing Role

The amount of renewable energy and energy efficiency in New England has been growing rapidly, though it will be many years before it may match the amount of natural gas capacity currently on the system and proposed for development.

Notes: All values are nameplate capacity, except for existing natural gas, which reflects summer seasonal claimed capability for generators reporting natural gas as a primary or alternate fuel. Solar power values reflect existing and proposed grid-connected resources, as well as existing and forecasted behind-the-meter resources. The energy-efficiency values reflect resources participating in the capacity market, as well as forecasted future capacity.

Sources: ***ISO-NE Generator Interconnection Queue*** (January 2017), ***2016 CELT Report, Final 2016 ISO-NE Solar PV Forecast, DGFWG August 2016 Survey Results***, and ***Final Energy-Efficiency Forecast Report for 2020 to 2025***

Out-of-Market State Subsidies Can Undermine the Competitive Marketplace

Markets work well when their prices reflect the costs of building and operating power-supply resources. Accurate prices are a cornerstone of competitive markets that motivate and compensate resources to make cost-effective investments. State policies that subsidize renewable resources can interfere with accurate pricing in the energy markets because these subsidies offset operating costs. This enables subsidized resources to sell energy for artificially low prices, putting traditional generators that New England needs for reliability at a price disadvantage.

To make up lost energy-market revenue and remain financially viable, power resources needed for reliability will have to raise their offers in the long-term capacity market. It's critical, therefore, that state-subsidized renewables don't also suppress prices in the capacity market by bidding at artificially low prices. To ensure accurate capacity pricing, the ISO has developed capacity market rules that prevent resources from bidding below their actual costs. As a reasonable balance between these rules and state actions, the capacity market allows a limited amount of state-subsidized renewable resources to enter the market and be counted toward meeting the region's capacity needs.

However, as more state-subsidized renewables come on line, that limit will begin to exclude more and more such resources from the capacity market. This means they won't be counted toward the region's capacity needs; other types of resources will be developed and counted instead. This is an inefficient and potentially costly outcome for electricity consumers who ultimately will fund both the resources that clear the wholesale market and count as capacity resources, as well as the excluded renewables that are subsidized through state-mandated charges on retail electricity bills.

Ensuring the capacity market can both sustain the traditional generation resources needed for reliability and accommodate more state-subsidized renewables is a conundrum with no simple solution. (Learn more in the ISO discussion paper, ***The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future***.)

The Region Is Exploring Ways to Better Accommodate State Goals within the Competitive Marketplace

The New England Power Pool (NEPOOL), the association of regional market participants, launched the Integrating Markets and Public Policy (IMAPP) Initiative in 2016 to explore ways to leverage the competitive marketplace to meet the New England states' respective environmental goals. The ISO has participated in the discussions and will continue to work with NEPOOL and the New England states on issues and proposed changes. The implementation of these emerging ideas is likely several years away. To follow the effort, visit **www.iso-ne.com/IMAPP**.

As the **power system's resource mix** evolves, the ISO is also pursuing other innovative market refinements to ensure appropriate compensation for resources making critical contributions to reliability, such as by providing fast response, flexible operation, and voltage and frequency support. Follow projects to improve price formation using the Wholesale Markets Project Plan webpage at **www.iso-ne.com/wmpp**.

Ensuring the capacity market can both sustain the traditional generation resources needed for reliability and accommodate more state-subsidized renewables is a conundrum with no simple solution.

ISO Metrics

Measuring ISO New England's Performance and Contribution to the Region

Accountability and Transparency

Open, fair, and independent decision-making are the defining characteristics of ISO New England. To ensure the highest levels of transparency, industry stakeholders are an integral part of the ISO's budget processes, regional system planning, and market development. They also interact regularly with ISO staff and directors, take part in the nomination of the ISO Board, and participate in dozens of committees and working groups.

For example, in 2016:

- The ISO coordinated or participated in about 60 meetings of the **Markets, Reliability, Transmission, and Participants Committees**, as well as 17 **Planning Advisory Committee** meetings, which stakeholder representatives from over 100 entities attended.
- The **Consumer Liaison Group** met quarterly to share information about the economic impacts of New England's power system and wholesale electricity markets on consumers.
- **ISO Customer Support** handled almost 14,000 calls and helped customers resolve 7,700 issues.
- Over 1,000 stakeholders attended ISO **classroom or web-conference trainings**.
- About 50 **e-learning modules** and 170 **presentations** were maintained on the ISO website for stakeholder use.

A Robust Stakeholder Process

Interested parties, with their diversity of perspectives, expectations, interests, and ideas, can help inform discussion and generate solutions to regional challenges and effective outcomes for New England's consumers and market participants. The ISO's stakeholders are a wide-ranging group, including:

- The **New England Power Pool** (NEPOOL)
- **State regulators**, including the New England Conference of Public Utilities Commissioners (NECPUC)
- **State and federal legislators, attorneys general, and environmental regulators**
- The **six governors**, primarily through the New England States Committee on Electricity (NESCOE)
- The **Consumer Liaison Group**, a forum of electricity consumers and state consumer advocates

Results on a Budget

We maintain a culture of cost accountability and transparency in our service to the region. The ISO is a not-for-profit entity without equity—as such, we rely on collections under the ***ISO New England Transmission, Markets, and Services Tariff*** to fund operational expenses. Our **rigorous annual budgeting process** includes meaningful stakeholder input, oversight from the ISO Board, and review by the Federal Energy Regulatory Commission.

The ISO's 2017 **operating budget** is **$192.7 million**—an increase of 4.1% over the 2016 budget—before incorporating the prior years' true-up (actual expenses versus budgeted collections).

- More than half the increase is necessary to maintain the ISO's current operations by funding competitive compensation, software licenses and maintenance, and retirement and medical benefits. The budget includes no new hires for 2017.
- Most of the remaining increased costs are attributable to cybersecurity enhancements, participation in the IMAPP initiative, and compliance with FERC orders.

$1.12 per Month

The services and benefits the ISO provides to keep the power flowing will cost the average New England residential electricity consumer $1.12 per month in 2017, based on 750 kilowatt-hours per month usage. This is a slight increase from $1.08 per month in 2016.

(Note: The 2016 cost was previously reported as $0.99 per month; however, a new calculation method now accounts for reduced projected annual energy use due to behind-the-meter solar power and energy-efficiency measures.)

The ISO's financial statements and other metric reports are available at **www.iso-ne.com/about**.

Customer Satisfaction

Stakeholder feedback is a helpful indicator of the quality of the products and services the ISO offers, as well as areas needing improvement. The latest survey of market participants (2016) revealed high overall satisfaction levels. Positive satisfaction among respondents with an opinion was **96%**.

Enhancements to the ISO Website

Enhancements to the ISO website and data portal, ISO Express, continue. Of note in 2016:

- The **new webpages Annual Work Plan, Wholesale Markets Project Plan**, and **Customer Readiness 12-Month Outlook** help stakeholders track projects and prepare for changes.
- A **new ISO Express graph** shows the real-time fuel mix by megawatt. This complements the enhanced real-time fuel-mix chart launched in 2016, which better reflects the percentage of each fuel that dual-fuel units are using. ISO Express' default dashboard has also been redesigned to include more data, and the pricing data reports are now easier to use.
- The **FCM Participation Guide enhancements** provide more helpful guidance for operating in the Forward Capacity Market.
- **Expanded webpages** such as **Current Power System Status** now include all 11 possible actions from ISO Operating Procedure No. 4: *Action during a Capacity Deficiency*; notifications are also now timestamped and specify the affected areas of the system.

A Focus on Performance and Standards Compliance

The ISO is dedicated to the safe, reliable operation of the grid through extensive training for staff and continuous process improvement to ensure compliance with directives from FERC, the North American Electric Reliability Corporation (NERC), and the Northeast Power Coordinating Council (NPCC).

In its last audit, the NPCC recognized the ISO for areas of excellence. The 2015 Operations and Planning Compliance Audit assessed ISO compliance with 38 standards and 124 requirements addressing power system reliability. The NPCC Audit Team lauded the ISO's operating performance over the previous three years and concluded that it had no improvement recommendations or areas of concern for the ISO.

Cybersecurity

The US Department of Homeland Security reports that the energy sector has become a major target of cyberintrusion attempts. If a widespread cyberattack on generators succeeded in knocking out just 7% of units (about 50) across New England, New York, and other parts of the Northeast, it could leave over 90 million people without power and have an over $200 billion impact on the economy, according to a 2015 report by Lloyd's and the University of Cambridge Centre for Risk Studies. This is an unlikely, yet possible, scenario. In light of these and other serious risks, the ISO is committed to making sure our systems remain secure:

- To be able to detect, withstand, and recover from any cyberattacks, we've implemented an **extensive system of process controls, advanced detection and response systems, and redundancy** in systems and control centers.
- Our **24/7 Security Operations Center** provides round-the-clock monitoring of the ISO network, and a 2017 project will apply best practices for isolating access to networked services and systems internally.
- We've **tightened security controls** for cyberassets and visitors to ISO facilities, in compliance with NERC's revised critical infrastructure protection cybersecurity standards. We'll also be tightening security controls for hardware, software, and services associated with system operations, in response to anticipated NERC standards for supply-chain management.
- The ISO participated in NERC's GridEx III exercise on cybersecurity and physical security in November 2015 and will be participating in GridEx IV in 2017. Additionally, all ISO employees participate in **annual cybersecurity training**.

If a widespread cyberattack on generators succeeded in knocking out just 7% of units ... across New England, New York, and other parts of the Northeast, it could leave over 90 million people without power.

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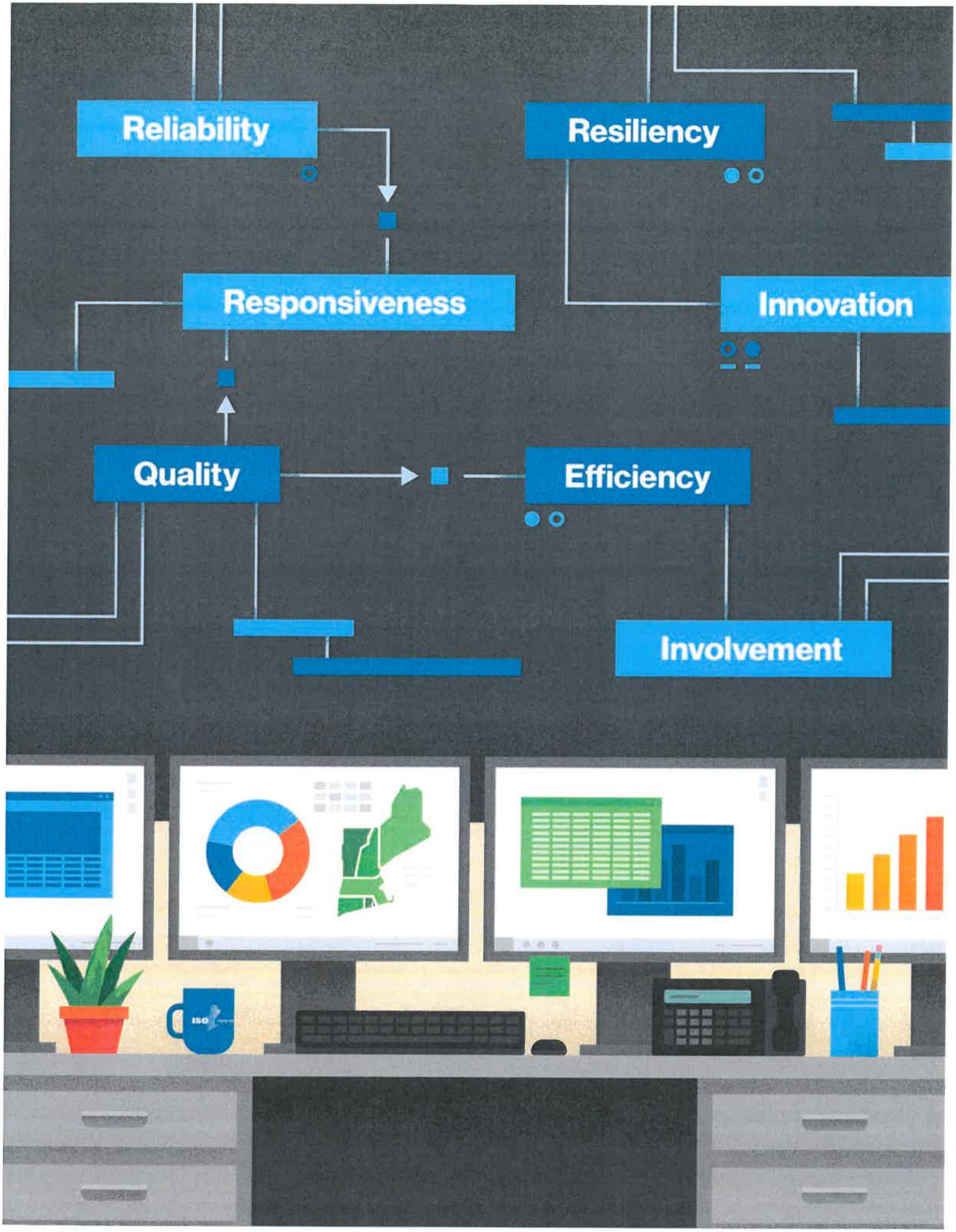
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EXHIBIT RH-5

Anne C. George
Vice President
External Affairs and Corporate Communications

February 20, 2017

Mr. Martin Suuberg
Commissioner
Massachusetts Department of Environmental Protection
One Winter Street
Boston, Massachusetts 02108

Dear Commissioner Suuberg:

ISO New England, Inc. (ISO) appreciates the opportunity to comment on the Massachusetts Department of Environmental Protection's (MA DEP) proposed regulations to implement Section 3(d) of the Global Warming Solutions Act (GWSA). The MA DEP has proposed a comprehensive set of regulations that together seek to address the mandates from the GWSA, the Massachusetts Supreme Judicial Court's decision in *Kain v. Department of Environmental Protection*, and Governor Baker's Executive Order 569. The ISO acknowledges that no single element of the proposed regulations is intended to address all of the mandates; however, the ISO is limiting its comments to the proposed regulation (310 CMR 7.74: *Reducing Greenhouse Gas Emissions From Electricity Generating Facilities* (EGU limit regulation)).

The ISO recognizes the efforts of Massachusetts to reduce greenhouse gas (GHG) emissions, and provides these comments to assist the commonwealth in achieving those reductions in a reliable, efficient and cost-effective manner for the state and ultimately the region.

The ISO has reviewed the proposed regulation that caps emissions at electric generation plants in Massachusetts, and given the limited time for analysis, was able to conduct a high-level assessment of the rules' impact on regional generation, emissions and wholesale electricity costs.

The results of our analysis indicate that under the proposed regulation, the region can maintain reliable electricity service by shifting electricity production from power plants in Massachusetts to other states. This shift in electricity production, however, can increase regional emissions and raise wholesale electricity costs. Generally speaking, the ISO's analysis shows a modest increase in regional emissions, because electricity production is shifted from Massachusetts to less efficient plants and likely higher emitting fuel sources in the region.

The regional cost of electricity also increases under the ISO's analysis. While the ISO's analysis suggests modest emissions and cost increases (ranging from $0.00 - $0.35/MWh), it appears that the state will have difficulty meeting its desired carbon emission reductions from the electricity sector if it relies solely on the regulation because these limits, if they are binding, actually increase the emissions associated with Massachusetts electricity consumption. The more stringent the emissions limits, the greater the effect.

Assuming these regulations move forward, the ISO has three specific recommendations that can further improve the efficiency of the rules and mitigate cost and regional emissions increases and help ensure reliable electric service for the commonwealth and the region.

First, the **ISO suggests the state utilize an auction to allocate carbon emission credits** to electricity suppliers rather than employing an administrative process that awards initial emission credits based on historical use, projected future emissions, or some other criteria. An auction will allow market participants to reflect their private valuation for emissions credits while accounting for expected production, potential capital investments that could reduce emissions, future market conditions, and their risk tolerance. The auction would sell these credits to the set of market participants who value them most. This is an efficient outcome as it awards the credits to the resources that maximize the value of the credits, and allows the state to cost effectively meet its environmental objective.

This efficient allocation does not occur under an administrative process where the credits are not allocated to the resources that value them most, and instead uses an alternate framework such as historical emissions, which may not be indicative of emissions going forward. To the extent that the trading of permits between resources is limited (either because of poor information about their market value or market power that limits the set of counterparties), the most cost effective set of resources would not be able to deliver energy, which would increase total costs and emissions relative to an efficient distribution of permits.

Additionally, because an auction sends a transparent price signal to all participants about the value of an emissions credit, it may increase the emission credit market's liquidity by helping to facilitate the trading of credits after the auction, which will inevitably be necessary as plant and market conditions evolve. This increased liquidity will help ensure that the state meets its environmental objective in a cost effective manner, and will reduce a resource's risk of incurring financial penalties because it cannot procure sufficient credits to offset its carbon emissions.

Second, the **ISO suggests that the proposed regulation should not supersede current air permit limits for generators with new administrative caps**. Such a move would render plants unable to run even if credits were available to them through an auction or post-auction secondary market. The transfer of credits between facilities is already contemplated by the draft regulations in 310 CMR 7.74(6)(c), albeit on the limited basis of the transfer of over compliance credits to other facilities. But even on that limited basis, a new cap in an air permit would limit a plant to the pre-credit transfer emissions. The draft proposal to cap air permits at the administrative cap is problematic in that it could curtail newer, cleaner and more efficient resources from operating and result in older and less efficient resources operating in their place.

Third, **the regulation should include a mechanism to mitigate any negative impact to electric reliability.** This could be structured as a reliability safety valve wherein a resource could operate past its credit allotment for reliability-related reasons[1] with a 1-for-1 repayment rather than a 3-for-1 repayment. Alternately, if emissions credits are auctioned there could be a provision to "buy through" into next year's quantity at a multiple of the current year's auction value. This value could be high enough to prevent casual use of the provision, but would provide valuable certainty to both plant owners and the ISO.

Background

Created in 1997, the ISO is the independent, not-for-profit corporation responsible for the day-to-day reliable operation of New England's bulk power generation and transmission system; development and operation of the region's wholesale electricity markets; and management of a comprehensive regional bulk power system planning process. The ISO serves the New England region which includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. The ISO is regulated by the Federal Energy Regulatory Commission (FERC).

Since their start in 1999, New England's competitive wholesale electricity markets have resulted in significant efficiencies and stimulated billions of dollars of private investment in approximately 16,000 MW of new generation. The region's transition to competitive markets has shielded ratepayers from bad investment decisions and has spurred the development of a more efficient and flexible fleet of resources, which are now able to deliver power to customers from the most efficient resources around the region thanks to investments in transmission infrastructure.

The competitive wholesale electricity markets, coupled with an abundance of relatively cheap natural gas nearby, as well as environmental regulations and policies have driven changes in New England's resource mix and utilization. Since 2000, the New England power system has undergone a major transformation – the region has shifted to natural gas-fired generation. Almost half (49%) of the electricity produced in New England in 2016 was derived from natural gas – up from 15% in 2000. Over the same period, electricity produced from coal and oil combined dropped from 40% to about 3%. This transformation has brought benefits and challenges to the region.

The region's shift in fuel from coal and oil to less-emitting sources, primarily natural gas, has resulted in significant reductions in emissions from the region's electricity generating fleet. From 2001 to 2014, annual emissions for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and carbon dioxide (CO_2) declined by 66%, 94%, and 26%, respectively. However, over the past several winters, when natural gas supply to electric generation is limited or more expensive, the New England states have relied on oil and coal to produce the electricity the region needs.

The region's wholesale electricity markets and the enabling investment in the transmission to allow for competition between resources have served the region well over the past two decades, resulting

[1] For example, reliability-related reasons could include an order to operate by the United States Secretary of Energy under Section 202 (c) of the Federal Power Act. (See 16 U.S.C. § 824 a (c) (2016)).

in the efficient use of resources and attracting investment in cleaner, more efficient generation and demand resources in the region.

While the shift in the resource mix has brought benefits to the region, it has also brought challenges. The upcoming retirement of non-gas-fired generators (including Brayton Point and Pilgrim Nuclear which account for 2,100 MW of capacity) exacerbates New England's dependence on a constrained natural gas system and represents a challenge for us as the regional system operator. These operational challenges are not likely ending anytime soon, as half of the proposed power plants in the region are gas-fired. Furthermore, these challenges are made even more acute if these proposed rules limit production, or hasten the retirements, of non-gas generation.

Proposed Regulation

The proposed EGU limit regulation establishes an aggregated state limit with respect to GHG emissions as well as a declining limit on GHG emissions from both new and existing power plants in the state. The cap for each plant, as well as the aggregate limit, will decline at a rate of 2.5% each year from 2018 to 2050. New facilities receive a set portion of the aggregate limit, which stays constant until 2025 before declining at the same rate as the existing plants. The regulations allow for over-compliance credits to be created in an annual compliance period, which can be transferred among power plants in the state or retained for future use.

ISO Analysis

The ISO conducted a modeling study in an attempt to identify the potential impact of the proposed EGU limit regulation. While no model captures all of the variables that can occur in the regional power system, the model simulates various scenarios in which to evaluate the impact of the regulation.[2]

The ISO's analysis simulated the year 2025 for two resource scenarios and then considered sensitivities that included additional hydro imports and offshore wind.[3] The ISO believes that, while it is impossible to know exactly what future years will look like, the qualitative results are informative and robust across a range of possible futures.

The ISO's analysis shows that the design of the proposed EGU limit regulation has consequences to Massachusetts and the other New England states due to the regional nature of the electric power system. Under this proposed regulation, Massachusetts seeks to meet emissions goals by limiting in-state generation which in turn shifts generation to resources in other states to make up the energy shortfall. Our modeling results show that when this occurs, relatively efficient clean burning

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[2] It should be noted that the model does not include potential constraints on the natural gas pipeline system. As ISO New England has discussed in several reports, fuel security is a critical challenge for the region.

[3] The ISO's analysis utilized existing base cases, scenarios and assumptions from the region's 2016 Economic Study.

facilities in Massachusetts are operated less, and relatively inefficient and less clean resources in other states are run more. When the additional emissions associated with the incremental non-Massachusetts generation are added back to Massachusetts, emissions totals attributable to Massachusetts under the regulation actually increase under the proposed policy. Total New England emissions increase by the same amount attributable to the policy.

The degree to which emissions and costs increase under the policy is directly related to the cap. The results range from no effect if the cap is not binding (*i.e.* does not limit generator output) to increases in generator offers, consumer costs, and emissions if the cap requires shifts in generation. While the ISO is only presenting results from a small possible shift in emissions in 2025, we did evaluate the effect of greater shifts under the cap that might be applicable if loads are higher than modeled, or that might occur in later years as the caps become increasingly tight. In each case, as the caps get more restrictive, costs and emissions increase. These model results also assume a perfectly efficient distribution of credits – to the extent that credits are not distributed efficiently – costs and emissions will be higher.

Our analysis indicates that the proposed rules in the best case, with a non-binding cap, would show no effect. If the emissions limits are binding they should be expected to raise consumer costs and *increase* carbon emissions associated with Massachusetts. The less efficient the final allocation of credits is, the greater the costs and emissions.

Similarly, in most of the scenarios we conducted in our analysis[4] (absent additional imports and off-shore wind), we saw locational marginal price increases between \$0.00/MWh and \$0.35/MWh.

Recommendations
The ISO believes our suggestions below will reduce as much as possible the cost and regional emissions impacts discussed above.

Credits Should be Allocated by Auction Rather than a Plant-by-Plant Assignment
The ISO suggests the state utilize an auction to allocate carbon emission credits to electricity suppliers rather than employing an administrative process that awards initial emission credits based on historical use, projected future emissions, or some other criterion.

An auction will allow market participants to reflect their private valuation for emissions credits while accounting for expected production, potential capital investments that could reduce emissions, future market conditions, and their risk tolerance. The auction would sell these credits to the market participants who value credits the most, which is an efficient outcome that allows the state to cost effectively meet its environmental objective.

[4] A detailed summary of the ISO's emissions and cost analysis is included in the materials immediately following these comments.

This efficient allocation does not occur under an administrative process which instead uses an alternate framework such as historical emissions, which may not be instructive of emissions going forward. To the extent that the trading of permits between resources is not permitted or is limited, such a design would prevent the most cost effective set of resources from delivering energy while also meeting the state's environmental objectives, thereby increasing total costs and emissions relative to an auction design.

Additionally, because an auction sends a transparent price signal to all participants about the value of an emission credit, it will help to facilitate the efficient trading of credits after the auction that will inevitably be necessary as plant and market conditions evolve. This increased liquidity relative to an administrative allocation will help ensure that the state meets its environmental objective in a cost effective manner, and will reduce a plant's risk of incurring financial penalties because it cannot procure sufficient credits to offset its carbon emissions. In the process, an auction-based allocation would value the carbon credits and create revenue that could be invested in energy policies that further the state's greenhouse gas goals.

Furthermore, because a ton of carbon emissions has an equivalent impact whether from a new or existing generation resource, the regulations should not separate existing and new resources into different categories. Rather, all resources should be allowed to value and procure carbon emission credits based on the performance characteristics of a generating facility. This should have the effect of more credits being procured by the set of resources that values them most, which would allow Massachusetts to meet its environmental objectives in a cost effective manner.

In order to help generators better manage their procured credits over the course of an operating year, the ISO suggests that the carbon auction's emission year should be consistent and aligned with the region's electric power year which runs from June 1 to May 31. This timing is consistent with the timing of the region's annual Forward Capacity Market. This will have the added reliability benefit of moving the end of the emission year from December, a time when the electric system is particularly challenged due to fuel limitations on the existing natural gas system. Stated another way, moving the timing will allow generators to better manage their allocations and ensure that these resources are available when the system experiences peak electricity demands.

Current Generator Plant Air Permits Should Not be Superseded by New Plant Limits
Proposed 310 CMR 7.74 (12) specifies that the individual GHG emission limits provided in 310 CMR 7.74 (5) replace the declining annual CO_2 emissions limits in an individual facility's plan approval issued pursuant to 310 CMR 7.02. We recommend that this provision should be removed as it is incompatible with the more efficient auction and secondary trading market design discussed above.

Newer resources with declining annual CO_2 emissions limits (issued pursuant to 310 CMR 7.02) offer the commonwealth the opportunity to leverage less carbon intensive generation from amongst the most efficient, least emitting and most economic resources. By replacing 310 CMR 7.02 declining annual CO_2 emissions limits with the 310 CMR 7.74(5) individual GHG emission limits, the generator emissions cap will likely require higher emitting and more expensive resources around the region to operate to make up the shortfall.

The Regulations Should Include a Mechanism to Mitigate Potential Reliability Concerns
Power systems can experience unexpected events that require the operation of power plants to ensure power system reliability. A key to that is the dispatch of generation in a given area to create the necessary real and reactive energy to serve load and unload stressed power lines.

While the draft regulation contains a 3-for-1 repayment for operating over a given limit, the ISO suggests that the repayment methodology should be modified to also provide a reliability safety valve under which generators that have exhausted their procured credits and are dispatched for system reliability needs would repay over-emission on a 1-for-1 basis. Generators that over-emit under these circumstances could then offset that over emission in the next operating year or through procuring additional credits in the secondary market if they are available.

Alternately, an auction could be designed to include a predetermined financial penalty for any carbon emitted in excess of a resource's credits or allow a resource to buy-through to the following year. A known financial penalty would provide resources with certainty and allow them to incorporate the potential penalty into their electricity market offers.

Conclusion
Thank you for this opportunity to provide comments. Given our unique role as operator of the regional power system, ISO New England believes the recommendations outlined above will improve the efficiency of the proposed rule and mitigate the reliability, environmental and cost impacts of the proposed EGU limit regulation.

Sincerely,

Anne C. George

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Vice President, External Affairs and Corporate Communications

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