

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Grid Resilience in Regional Transmission                    )           Docket No. AD18-7-000  
Organizations and Independent System Operators        )

**RESPONSE OF  
ISO NEW ENGLAND INC.**

ISO New England Inc. (“ISO-NE”)<sup>1</sup> respectfully submits this response to the Federal Energy Regulatory Commission’s (“Commission”) January 8, 2018 *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures* in the captioned proceeding.<sup>2</sup> As the Resilience Order acknowledges, resilience challenges will differ in each region operated by a regional transmission organization or independent system operator (“RTO/ISO”). ISO-NE agrees and appreciates the opportunity to continue working with New England’s stakeholders on resolving the particularly resilience issues facing the New England region.

In New England, the most significant resilience challenge is fuel security – or the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability. ISO-NE is already at the forefront of this issue. As discussed below, ISO-NE conducted an Operational Fuel-Security Analysis (“OFSA”)<sup>3</sup> to quantify the fuel-security risk, and to frame regional discussions on addressing it. ISO-NE’s goal in addressing the fuel-security risk is to develop a long-term market solution that will maximize the likelihood that generators have

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<sup>1</sup> Capitalized terms used but not otherwise defined in this filing letter have the meanings ascribed thereto in the ISO’s Transmission, Markets and Services Tariff (the “Tariff”). Section II of the Tariff contains the Open Access Transmission Tariff (the “OATT”), and Section III of the Tariff contains Market Rule 1.

<sup>2</sup> *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) (“Resilience Order”).

<sup>3</sup> The results of the OFSA are documented in the report attached herein as Attachment A. ISO New England Inc., *Operational Fuel-Security Analysis* (Jan. 17, 2018).

sufficient fuel to meet the region's winter electricity needs. ISO-NE is already actively engaged with regional stakeholders on the region's fuel-security risk, and has established a process to discuss market-based solutions to address this risk. In the stakeholder discussions, ISO-NE has previously stated that a range of solutions from changes to Pay For Performance parameters to market designs that increase incentives for forward fuel supply and re-supply to inclusion of opportunity costs associated with scarce fuels and emission allowances will need to be evaluated as part of the stakeholder process. Given the complexity of the problem, ISO-NE believes it will be necessary to allow the region sufficient time (through the second quarter of 2019) to develop a solution and test its robustness through New England's established stakeholder process.

In the meantime, as the RTO and System Operator responsible for the bulk power system's reliability,<sup>4</sup> ISO-NE will continue to independently assess the level of fuel-security risk to reliable system operation. If circumstances dictate that the region's fuel-security challenges become more pressing before a long-term solution can be developed and implemented, ISO-NE will take (with the Commission's approval, when required) actions that it determines to be necessary to address near-term reliability risks.

To facilitate the Commission's consideration of New England's resilience challenge, Part I of this response introduces the fuel-security risk. Part II provides an extensive background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience. Finally, Part III addresses the specific questions posed in the Resilience Order.

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<sup>4</sup> ISO-NE is also the NERC Reliability Coordinator and Balancing Area Authority for the region, as well as the FERC-designated entity in charge of regional transmission system planning.

## I. INTRODUCTION

The Resilience Order, terminated a rulemaking initiated by the United States Department of Energy's Proposed Rule on Grid Reliability and Resilience Pricing,<sup>5</sup> and established the instant proceeding to examine the resilience of the bulk power system in RTO/ISO regions. As the Resilience Order explains:

[W]e have seen a variety of economic, environmental, and policy drivers that are changing the way electricity is procured and used. These changes present new opportunities and challenges regarding the reliability, affordability, and environmental profile of each region's electric system. These changes may impact the resilience of the bulk power system. As we navigate these changes, the Commission's markets, transmission planning rules, and reliability standards should evolve as needed to address the bulk power system's continued reliability and resilience.<sup>6</sup>

In this proceeding, the Commission seeks to comprehensively examine the bulk power system's resilience with the goals of developing a common definition of resilience, how each RTO/ISO assesses resilience in its region, and evaluating whether further Commission action regarding resilience is necessary. To those ends, the Resilience Order directs each RTO/ISO to respond to a series of questions seeking information on how it understands resilience, assesses resilience in its respective region, and mitigates resilience risks.<sup>7</sup>

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<sup>5</sup> *Grid Resilience Pricing Rule*, 82 Fed. Reg. 46,940 (Oct. 10, 2017).

<sup>6</sup> Resilience Order at P 17.

<sup>7</sup> *Id.* at P 23 (noting that the Commission understands resilience to mean "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recovery from such an event."). *See id.* at 19 (emphasizing, "[t]he efforts of RTOs and ISOs on grid resilience encompass a range of activities, including wholesale electric market design, transmission planning, mandatory reliability standards, emergency action plan development, inventory management, and routine system maintenance.").

## A. ISO-NE's Understanding of Resilience

As an RTO, ISO-NE is responsible for planning and operating the New England bulk power system, and ensuring its reliability based on applicable standards and criteria established by the North American Electric Reliability Corporation (“NERC”) and the Northeast Power Coordinating Council (“NPCC”). In assessing reliability, ISO-NE considers two key aspects of the bulk power system: (1) security (*i.e.*, the system’s ability to withstand unexpected disturbances, such as loss of system elements), and (2) adequacy (*i.e.*, the system’s ability to supply the energy to meet demand, accounting for scheduled and reasonably expected unscheduled outages of system elements).<sup>8</sup> For the system to be resilient – *i.e.*, able to withstand and reduce the magnitude and/or duration of disruptive events – both of these aspects of reliability need to be addressed. As described in Part II.A of this response, ISO-NE’s work in planning, markets, and operations to help ensure that the region has the power resources and transmission facilities necessary to meet demand and reserve requirements results in a bulk power system that has many attributes of a resilient system, as defined by the Commission.

The resilience of the New England power system, however, is being increasingly challenged by the possibility that the region’s generating fleet will not have, or be able to obtain, the fuel they need to produce the power required to meet system demand and maintain required reserves, particularly during extended periods of winter (or other system-stressed) conditions. The role of generators’ fuel arrangements in real-time system reliability is what ISO-NE refers to as “fuel security.”

This response focuses on New England’s fuel-security challenges. ISO-NE recognizes that fuel security is just one aspect of the bulk power system’s resilience;<sup>9</sup> however, it is the most significant challenge for the New England bulk power system’s resilience, and it currently has no defined long-term solution. In contrast to fuel security, significant efforts to address other

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<sup>8</sup> ISO-NE’s consideration of the bulk power system’s security and adequacy is consistent with NPCC’s definition of “Reliability,” as reflected in NPCC’s Northeast Power Coordinating Council, Inc., Glossary of Terms (Oct. 26, 2011), <https://www.npcc.org/Standards/Directories/Glossary%2020171103.pdf> (“NPCC Glossary”).

<sup>9</sup> See Resilience Order at P 19 (referring to “secure onsite fuel” as “one possible aspect of grid resilience”).

important issues that can affect grid resilience are already underway in other forums. These include cybersecurity, physical security, and geomagnetic disturbances.<sup>10</sup>

## **B. Introduction to New England’s Fuel Security Challenges**

A reliable supply of electricity hinges on the generation fleet’s ability to have, or be able to obtain, the fuel it needs to produce electricity. Fuel supply, in turn, requires a fuel-delivery system that has the appropriate physical capability to transport all the fuel needed, the contractual arrangements secured in advance to ensure timely deliveries, and/or power plants that have fuel storage on site and the ability to operate using the on-site fuel.

The New England region does not have any indigenous fossil fuels production. Accordingly, the region’s generation fleet relies primarily on fuels imported from elsewhere in the United States and Canada, as well as from overseas by ship, truck, pipeline, or barge, giving fuel procurement, transportation, and storage a pivotal role in power system operations. Challenges with fuel procurement, transportation and storage are most acute with natural gas, on which the regional power system is increasingly dependent for power generation.<sup>11</sup> The natural gas-fuel infrastructure in the region is built to a level to meet the peak demand needs of the entities contracting for that capacity. In New England, most gas-fuel infrastructure is under

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<sup>10</sup> *See id.* at P 12 (identifying, “[t]he Commission has conducted significant work to address bulk power system reliability through North American Electric Reliability Corporation (NERC) reliability standards, including its continued work on Critical Infrastructure Protection standards to protect the system against cybersecurity and physical security threats, as well as geomagnetic disturbances.”).

ISO-NE has implemented an extensive system of process controls, advanced detection and response systems, and redundancy in systems and control centers to help detect, withstand, and recover from any cyberattacks, as well as to comply with mandatory standards. For example, ISO-NE’s 24/7 System Operations provide round-the-clock monitoring of the technology network, and measures have been implemented to further tighten access to networked services and systems. Further efforts are forthcoming in 2018 in response to NERC standards for supply-chain risk management. Fully redundant systems at the backup control center also enable system operators to continue managing grid reliability in the unlikely event that the master control center is rendered inoperable. ISO-NE has also participated in NERC GridEx exercises on cybersecurity and physical security, and conducts annual training for all ISO employees.

<sup>11</sup> The region has significantly shifted from oil and coal to natural gas over the past 17 years. The percentage of electricity generated from natural gas in New England has significantly increased from just 15% in 2000 to 48% in 2017, and it is expected to grow to 56% by 2026, rendering natural gas the fuel most used to produce the region’s electricity. *See* 2017 Regional System Plan at 98 (Nov. 2, 2017), <https://www.iso-ne.com/system-planning/system-plans-studies/rsp/> (“2017 RSP”).

contract to the local natural gas distribution utilities that serve retail gas consumers pursuant to their obligation to serve under all conditions.

Natural gas-fired power plants in New England typically rely on capacity released by local utilities in the secondary market. This secondary capacity, by definition, provides only as-available service; it is available when the primary shippers do not need the capacity to meet their customers' requirements. As a result, when firm shippers' demands are greatest – typically during cold weather – capacity may be unavailable for natural gas-fired generators when they need it to run.

New England's fuel-security challenges first surfaced in 2004, when the region experienced extremely low temperatures and particularly high demand for electricity, prompting concerns about market and system performance during severe cold weather conditions (the "2004 Cold Snap"). Since then, as discussed in Part II.A below, ISO-NE, working with regional stakeholders, has undertaken significant efforts, in the form of market design changes and operating procedures, systems, and tools, to help mitigate those challenges. ISO-NE has revised rules governing energy, capacity, and ancillary service markets to create incentives for resources to perform when needed, and to improve gas-electric coordination. Operating Procedures, systems, and tools have also been developed and implemented to further improve gas-electric coordination, and increase overall situational awareness. However, ISO-NE's operational experiences in recent winters, as well industry trends, indicate the New England power system is on a path toward greater fuel-security risk, and additional measures are needed to address the risk, including some that fall outside of ISO-NE's purview.

The increasing shift away from generators with on-site fuel to natural gas-fired generators relying on "just-in-time" fuel-delivery infrastructure (or to generators using inherently variable fuel, in the case of wind and solar) has further exposed the limitations of New England's existing fuel-delivery system and heightened the region's fuel-security risk, particularly during the winter. During the December 2017 and January 2018 cold weather stretch ("2017/2018 Cold

Weather Stretch”) in New England,<sup>12</sup> for instance, heating demand for gas during severe winter conditions utilized essentially all of the capacity of the region’s natural gas-fuel infrastructure, which resulted in substantially higher natural gas and (concomitantly) higher wholesale electricity prices, leading to (temporarily) oil and coal plants operating.<sup>13</sup> With oil-fired generation operating at or near capacity, oil supplies, as well as emission allowances,<sup>14</sup> at power plants around the region began to deplete rapidly over the two-week period,<sup>15</sup> making system operations extremely challenging and significantly increasing the reliability risk to the system.

Despite periods of highly volatile energy market prices, New England continues to see the retirement of coal, oil, and nuclear power plants, which, as recently experienced, are needed to maintain reliability when the natural gas-fuel infrastructure is unavailable to the generators. Constrained gas-fuel infrastructure also heightens the need for dual-fuel generating capability. However, the existing dual-fuel generating capability in the region is limited and permitting additional dual-fuel capability has proven difficult. Moreover, having the dual-fuel capability does not guarantee fuel availability as emissions restrictions are tightening dual-fuel generators’ ability to use the oil-firing capability, and replenishment may be challenging due to oil-delivery

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<sup>12</sup> While overall, the winter of 2017-2018 has been relatively mild, during the 2017/2018 Cold Weather Stretch average temperatures in all major cities in New England were below normal for at least 13 *consecutive* days, of which 10 days averaged more than 10°F below normal. See ISO-NE Presentation to NEPOOL Participants Committee, *Cold Weather Operations, December 24, 2017 – January 8, 2018* at 4, 8 (Jan. 16, 2018), [https://www.iso-ne.com/static-assets/documents/2018/01/20180112\\_cold\\_weather\\_ops\\_npc.pdf](https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf) (“2017/2018 Cold Weather Stretch Presentation”).

<sup>13</sup> For context, from December 1, 2017 until the cold weather stretch began, oil and coal plants contributed just 2% of the energy generated by New England power plants. During the cold weather stretch, these resources contributed a full third of the energy. During this time, natural gas-fired generators dropped from generating almost half the energy to just 24%. See ISO New England Inc. Presentation, *State of the Grid: 2018, ISO on Background* at 23-24 (Feb. 27, 2018), [https://www.iso-ne.com/static-assets/documents/2018/02/02272018\\_pr\\_presentation\\_state-of-the-grid\\_2018.pdf](https://www.iso-ne.com/static-assets/documents/2018/02/02272018_pr_presentation_state-of-the-grid_2018.pdf) (“State of the Grid 2018 Presentation”).

<sup>14</sup> During the first week of January 2018, some of the oil-fired generators that were running to keep the lights on were reporting to ISO-NE that they were nearing their annual emissions limits. See 2017/2018 Cold Weather Stretch Presentation at 23.

<sup>15</sup> While, overall, the winter of 2017-2018 has been relatively mild, during the 2017/2018 Cold Weather Stretch, New England generators burned through 2 million barrels of oil (84 million gallons), which is twice as much as the oil used by New England power plants during the entire year of 2016. The contribution of other types of generators was crucial. For instance, the electricity produced by the Millstone Nuclear Station during the two-week period was the equivalent of what could be produced by 880,000 barrels of oil, and the power from Mystic 8 and 9 units, which are fueled by LNG from the nearby Distrigas import facility, was the equivalent of more than 360,000 barrels of oil. See State of the Grid 2018 Presentation at 24-25.

system constraints. This leaves the New England region reliant on fuel that may not be available for power generation when it is needed the most, making it more challenging to maintain reliability.

In summary, while New England is meeting its resource adequacy requirements for *capacity* – which are based on expected summer peak demands – with the market mechanisms that are in place today, from an *energy* availability standpoint, the shift from generators with on-site fuel to generators relying on “just-in-time” fuel delivery is challenging the system’s adequacy and, therefore, its resilience, particularly during winter peak demands. More specifically, the constrained gas-fuel infrastructure is unable to supply all of the region’s increasing numbers of natural gas-fired generators. This fuel security risk is exacerbated by the difficulty in permitting dual-fuel generating capability, emissions restrictions limiting generators’ ability to operate on the alternate fuel, and the reality that aging oil, coal, and nuclear generators with fuel on-site are becoming less economically competitive and may seek to retire before the region has addressed the fuel-delivery constraints or added sufficient alternative resources to replace the retiring resources.

### **C. ISO-NE’s Assessment of Fuel Security Risk**

Because fuel-security is critical for New England’s power system reliability and resilience, it is incumbent on ISO-NE to further assess its potential impacts to system operations in the future. Accordingly, in 2016, ISO-NE launched the OFSA to further ISO-NE’s and the region’s understanding of the fuel-security risk and facilitate regional stakeholder discussions on how to address this risk. The OFSA had two key objectives: first, to understand the levels of risk to reliability ISO-NE would encounter as the grid operator under a wide range of possible combinations of generating resources and fuel mixes; and, second, in quantifying these scenarios, to provide regional stakeholders and policymakers information necessary to help ISO-NE and stakeholders determine what steps New England should pursue to mitigate the risks.

The OFSA differs from studies previously conducted by ISO-NE. In the OFSA, ISO-NE, for the first time, has conducted a deterministic analysis,<sup>16</sup> specifically designed to identify the season-wide operational impacts by not just looking at a single forecast winter peak day, but examining the potential impacts to the reliable supply of energy (as opposed to capacity needs) over the entire 90-day winter season (December, January, February),<sup>17</sup> and without considering market responses, fuel costs or prices, and emission constraints. While the study did not explicitly consider specific market responses, ISO-NE assumed that prices in each scenario would sustain the inputs to that scenario. For example, if a scenario assumed up to one billion cubic feet (“Bcf”) of liquefied natural gas (“LNG”) injection per day for the winter period, the study assumes that electricity prices were high enough to sustain that level of LNG injection. In addition, the study does not model the effects of growing emission constraints on the fossil-fired resources in the region, since these are a relatively recent phenomenon. Instead, the study uses a deterministic scenario analyses technique to examine winter power system reliability under different hypothetical resource mixes. In essence, the study scenarios can be viewed as proxies for possible market and policy responses in a fuel constrained system.

Specifically, the study examined a wide range of hypothetical power system combinations (23 resource and fuel-mix scenarios, as well as outages of key energy facilities)<sup>18</sup> based on resource trends and conditions in the region to assess whether enough fuel would be available to meet demand and maintain power system reliability throughout the entire winter of 2024-2025,<sup>19</sup> assuming no additional build-out of natural gas-fuel infrastructure within the study

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<sup>16</sup> See 2017 RSP at n. 84 (explaining, “[d]eterministic analysis are snapshots of assumed specific conditions that do not quantify the likelihood that the conditions examined will actually materialize. The results are based on analyzing the assumed set of conditions representing a specific scenario.”).

<sup>17</sup> To illustrate the difference between energy and capacity, while the region may have procured the capacity – *i.e.*, capability in terms of supply machines – to serve a peak load, in the absence of fuel, only some portion of that capacity will actually be able to produce energy. Thus, a region may have sufficient capacity but may not have sufficient fuel to produce electric energy from that installed capacity.

<sup>18</sup> This diversity in scenarios was intended to help ISO-NE and regional stakeholders understand how well these future system profiles, or other profiles that fall between them, could support power system reliability throughout an entire winter.

<sup>19</sup> While actual conditions could change earlier or later, winter 2024/2025 was chosen because the outlook for power system reliability by then is uncertain, largely due to the expected retirements of non-gas-fired power plants. The intervening years give the region time to act. ISO-NE has acknowledged at stakeholder meetings that the relevant

timeframe. It focused on the five resource variables most affected by market and policy responses, and used those variables as the key factors in the reliability of a future power system that must operate within the given fuel infrastructure constraints: retirements of coal- and oil-fired generators, the availability of LNG, dual-fuel generators' oil tank inventories, imported electricity from neighboring regions, and additional renewable resources. The study quantified each hypothetical scenario's fuel-security risk in terms of operational metrics by calculating the frequency and duration of energy shortfalls (*i.e.*, insufficient fuel to generate all the electricity needed) created by fuel supply limitations, requiring ISO-NE to employ actions in Operating Procedures, including emergency actions, up to and including load-shedding (or rolling blackouts).<sup>20</sup>

The OFSA's results provide a basis for comparing the fuel-security risk of each of the modeled, hypothetical resource combinations. The results of the OFSA suggest New England's limited fuel-delivery infrastructure will eventually cause severe reliability issues if fuel security is not addressed. One of the OFSA report's major conclusions is that the impacts of the current industry trends affecting the New England power system are moving in a negative direction, leading to a greater fuel-security risk.

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differences in assumptions between planning models (such as those used in Installed Capacity Requirement) and the model used in fuel security need to be addressed as part of the ongoing stakeholder process.

<sup>20</sup> ISO-NE's Operating Procedures used to maintain system reliability when insufficient fuel is available to generate all the electricity needed to meet forecasted electricity demand and reserves are:

- (1) Operating Procedure No. 4, Actions During a Capacity Deficiency ("OP-4"), which is the procedure used most often by ISO-NE system operators to maintain supply and demand in balance, avoid violating the 10-minute reserve requirement, and avert the need to implement load shedding.<sup>20</sup> OP-4 includes 11 actions. Actions 1 through 5 are designed to work with Transmission Owners, Market Participants and Neighboring Areas to manage through stressed system conditions. If Actions 1 through 5 are not sufficient to address the problem, ISO-NE may implement emergency Actions 6 through 11, which are more visible to the public, such as public appeals for conservation.
- (2) Operating Procedure No. 7, Action in an Emergency ("OP-7"), which the procedure ISO-NE follows to implement load shedding. This emergency procedure is used to reduce system load by local control centers opening distribution system breakers to disconnect the load via supervisory controls.

These operational metrics of the number and severity of energy shortfalls illustrate the level of risk involved in each scenario and the relative benefits of the key variables. See OP-4, [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op4/op4\\_rto\\_final.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf); OP-7, [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op7/op7\\_rto\\_final.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op7/op7_rto_final.pdf).

Specifically, the OFSA found that energy shortfalls due to *inadequate fuel supply* would occur with almost every fuel-mix scenario in winter 2024/2025, requiring frequent use of emergency actions to fully meet demand or protect the grid.<sup>21</sup> In 19 of the 23 hypothetical resource combinations, some level of load shedding<sup>22</sup> was required to maintain system balance. These conclusions suggest the system is currently maintaining a delicate balance that could easily be disrupted if any of the five key variables considered in the analysis trend in a negative direction. The OFSA’s findings also indicate that extended outages, or retirement, of any of the key energy facilities examined would have detrimental impacts on system reliability.

On the positive side, the OFSA results indicate that a resource mix with higher levels of LNG, imports, and renewables can help minimize system stress and maintain reliability. To achieve these, however, advanced arrangements for LNG with assurances for winter delivery, as well as investment in transmission infrastructure to support renewable resources and imports from neighboring systems, would be required.

Striving to address the region’s growing fuel-security risk, in January 2018, ISO-NE issued the OFSA and immediately initiated a regional stakeholder process. ISO-NE is actively engaged with regional stakeholders to develop a problem statement and identify a long-term solution to address the risk. Given the complexity of these issues, ISO-NE hopes that the stakeholder process on fuel-security will progress in two phases. In the first phase, which commenced in January, ISO-NE will continue discussions on the OFSA inputs and results, as well as conduct additional analysis based on stakeholder feedback. (Requests equating to hundreds of new scenario combinations were submitted, and ISO-NE is in the process of reviewing and organizing them into a meaningful and responsive set of stakeholder-led hypothetical scenarios.) This effort is intended to provide stakeholders with additional information on the reliability challenges presented by the region’s fuel security risk.

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<sup>21</sup> Emergency actions that the public might notice range from requests to conserve energy to load shedding as the last resort.

<sup>22</sup> See NPCC Glossary (defining “Load Shedding” as “[t]he process of deliberately removing (either manually or automatically) preselected customers’ load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.”).

In the second phase, which ISO-NE anticipates will take place from Q2 2018 to Q2 2019, ISO-NE will engage in discussions with stakeholders on possible long-term solutions to address the region's fuel-security risk. New England's fuel-security challenges do not lend themselves to easy solutions. Thus, the proposed timeframe is necessary to allow for a systematic and deliberative regional process for examining the risks and possible solutions – a complex undertaking.

#### **D. ISO-NE's Mitigation of Fuel Security Risk**

To the extent the Commission determines that further action is needed, ISO-NE respectfully requests that ISO-NE be afforded time to continue working with stakeholders, and be extended flexibility to permit the development of solutions that meet the unique fuel-security challenges facing the region, and are consistent with New England markets. A key question to be addressed in these discussions will be what level of fuel-security risk ISO-NE, the region, policymakers, and regulators are willing to tolerate.

Meanwhile, as the System Operator responsible for the system's reliability, ISO-NE will continue to independently assess the level of risk to reliable system operations. If the region's fuel-security challenges become more pressing, ISO-NE will take necessary actions to address these reliability risks until such time as a longer-term solution is developed and implemented. For example, ISO-NE may need to take steps to prevent key energy resources with on-site fuel from retiring, to refrain from dispatching certain resources economically during adverse weather conditions to preserve critical fuel stocks, or to utilize other targeted (yet to be identified) out-of-market actions.

## **II. BACKGROUND**

### **A. ISO-NE's Work in Fulfilling its Responsibility as the RTO Already Supports the New England Power System's Resilience**

As the RTO, ISO-NE has three critical responsibilities: (1) conducting regional system planning, which is coordinated with the region's Transmission Owners, neighboring systems,

and takes input from all stakeholders; (2) designing, administering and overseeing the region's competitive wholesale electricity markets; and (3) overseeing the day-to-day reliable operation of New England's generation and transmission system, which includes directing the central dispatch of generation and flow of electricity across the bulk power system to ensure availability of electricity to meet demand. ISO-NE's work in fulfilling each of these responsibilities, including the instruments and procedures it has developed and implemented, results in a robust, reliable, and therefore resilient, bulk power system.

### **1. Planning for a Transmission System that is Reliable**

To meet future system needs, ISO-NE undertakes various system resource and transmission planning activities.

ISO-NE is in charge of the regional transmission system planning process to help ensure that the regional transmission system can reliably deliver power to consumers under a range of future system conditions.<sup>23</sup> As part of this process, ISO-NE performs reliability assessments to identify power system needs and solutions for ensuring the reliability of the system. This facilitates the efficient operation of the markets through resource additions and transmission upgrades that serve to reliably move power across the system. The planning process also provides information through the Regional System Plan to regional stakeholders to signal where investment is needed. The region develops regulated transmission solutions to address identified needs, but will set aside those regulated transmission solutions if the market addresses the identified system needs.<sup>24</sup> If and as market resources come forward that can solve identified system needs, transmission plans are reduced in scope or cancelled.

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<sup>23</sup> See OATT, Attachment K. ISO-NE's Transmission Planning Guides, which document the steps in the Regional System Planning Process, as well as the assumptions used in ISO-NE planning studies are available on the ISO-NE website at <https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides>, and the Planning Procedures are available at <https://www.iso-ne.com/participate/rules-procedures/planning-procedures>.

<sup>24</sup> Market-based solutions can include new power plants to provide additional capacity and produce electricity; demand response resources that can meet capacity needs and reduce the amount of electric energy used; or transmission upgrades to interconnect generating facilities and merchant transmission facilities to the system.

To conduct system Needs Assessments, ISO-NE performs comprehensive analysis of the transmission system, accounting for many different factors that can affect the overall performance of the system, such as power plant outages, expected development of renewable resources, impact of public policy on the grid, and the interaction between the natural gas and electric power systems. ISO-NE analyzes the performance of the transmission system and identifies the system's needs based on a 10-year planning horizon in accordance with planning criteria and procedures established by NERC, NPCC, and ISO-NE. All transmission upgrades must meet reliability performance requirements, which help ensure a reliable electric power system design. This means, for example, ensuring that equipment will remain within its emergency ratings following the loss of a system element or the loss of multiple system elements that can result from a common event like the loss of two circuits that share a common tower. NERC reliability standards provide a robust baseline set of criteria that the system must be designed to meet. The NERC criteria ensure that the system is designed to be resilient to a wide range of possible events on the system. Over and above these criteria, NPCC includes more stringent testing, such as requiring the evaluation of the system with an element out of service and either the loss of two circuits on a common structure or loss of an element combined with the failure of a circuit breaker to operate. Transmission planning approaches in New England have been compatible with the perspective of ensuring system resilience. For example, New England considers more than one load level, including a 90/10 load forecast, reflecting only a ten percent probability of being exceeded due to weather whereas some areas only rely on a 50/50 forecast. New England also represents resource unavailability due to forced outages and then applies contingencies to this base condition, rather than treating forced outages only as one of the many contingencies to be tested.

The continuous analysis of the system pursuant to ISO-NE's planning role has resulted in the identification of transmission solutions and helped guide the development of transmission investments that are essential to maintaining reliability. Since 2002, New England has invested approximately \$10 billion in reliability-based transmission, with another \$2.3 billion in planned investments in the coming years. These investments have strengthened weak areas of the system, eliminating costly congestion, and enabled electricity to flow freely around the region, so the most-cost-effective resources can be used to serve load no matter where they are located,

providing significant cost savings for consumers. As a result of these investments, the region has a robust transmission system that has the ability to operate reliably under myriad operating conditions. The system's ability to withstand various transmission facility and generator contingencies and move power around without dependence on local resources under many operating conditions, in turn, results in a grid that is, as defined by the Commission, resilient.

Additionally, through the system planning process, ISO-NE implements the resource adequacy process to ensure that enough capacity is installed to meet long-term forecast demand and required operating reserves.<sup>25</sup> Through the Installed Capacity Requirement ("ICR") calculation, ISO-NE estimates the amount of capacity the system requires in a given year to support the demand for electricity during summer peak conditions. The ICR, assuming fuel adequacy, accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The ICR is intended to satisfy the peak demand forecast for New England, which fully considers energy efficiency and behind-the-meter generation – while maintaining the required reserve capacity. Specifically, ICR identifies the minimum amount of capacity (in MW) required to meet New England's resource-adequacy criterion as set forth by NPCC and ISO-NE – *i.e.*, the one-day-in-10 years loss-of-load expectation ("LOLE").<sup>26</sup> The capacity to meet system-wide and local-area capacity targets is subsequently procured through the Forward Capacity Market ("FCM"),<sup>27</sup> described further below.

In addition to procuring capacity resources to meet the region's forecast demand for electricity, ISO-NE also conducts analyses to determine the system's need for resources that can provide operating reserves and system regulation. This mix of "extra" resources must be able to respond quickly to system contingencies, provide regulation service, and serve peak demand.<sup>28</sup>

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<sup>25</sup> See Tariff at §§ III.1.9 and III.12.

<sup>26</sup> See 2017 RSP at n. 94 (explaining, "LOLE analysis is a probabilistic analysis used to identify the amount of installed capacity the system needs to meet the NPCC and ISO resource adequacy planning criterion to not disconnect firm load more than one day in 10 years.").

<sup>27</sup> See Tariff at § III.13.

<sup>28</sup> These generating resources can respond to contingencies within ten or thirty minutes, can either be synchronized (*i.e.*, spinning) or unsynchronized (*i.e.*, non-spinning) to the power system.

ISO-NE's operating-reserve requirements are set forth in Operating Procedure No. 8, Operating Reserve and Regulation ("OP-8"). To comply with those requirements, ISO-NE must maintain sufficient total operating reserves based on the system's largest first-contingency loss (*i.e.*, N-1),<sup>29</sup> and one-half of the next-largest contingency loss (*i.e.*, N-1-1). These losses typically consist of some combination of the two largest on-line generating units or imports on the HVDC Phase II interconnection with Quebec.

Additionally, in accordance with NERC and NPCC criteria, the system must be operated within applicable normal or emergency system limits. Specifically, after the loss of an element (*i.e.*, N-1 contingency), the system's power flows must respect facility limits, transient stability and system voltage limits, and must return to a secure operating condition after a preparation time (normally 30 minutes). To this end, ISO-NE's operating reserves are distributed throughout the system to ensure ISO-NE's ability to activate all reserves without exceeding system limitations, and allowing system operation to remain within established criteria. The related NERC and NPCC criteria are incorporated in Operating Procedure No. 19, Transmission Operations ("OP-19").

## **2. Administering Wholesale Electricity Markets to Help Ensure Adequate Supply to Maintain Reliability**

ISO-NE uses wholesale electricity markets to procure sufficient power resources to maintain reliability. Information provided in the Regional System Plan, together with pricing signals from New England's competitive markets, facilitate Market Participants' decisions regarding electricity supply resource investments. These investments help ensure that the grid operates reliably and adequate supply is available to meet demand under a variety of conditions. The system must have enough power plants producing electricity, available for reserve, and providing the services needed to keep the system voltage and frequency in balance during normal system conditions and when system elements are out of service, whether scheduled or unscheduled.

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<sup>29</sup> N-1 can be single contingency or multiple element contingency, such as the loss of Mystic 8 and 9.

New England’s competitive wholesale electricity markets (described below) have worked effectively to bring forward resources needed to meet the region’s capacity requirements, while reducing both power system emissions and wholesale power prices. The wholesale electricity markets designed and run by ISO-NE stimulate strong competition among over 500 buyers and sellers and have attracted billions of dollars in private investment in new resources, facilitating the shift to cleaner energy and lower emissions. New England’s energy markets are fuel-neutral and are based on the economics of participating resources. They select the lowest-priced power resources competing to produce electricity or provide other specialized services, compensating all suppliers on the same terms and conditions.

New England’s wholesale electricity markets and products include:

- Day-Ahead Energy Market (“DAM”) and Real-Time Energy Market (“RTM”): The DAM allows Market Participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real-time, and the RTM provides for the sale and purchase of wholesale electric power to meet the instantaneous demand for electricity. These markets incent resources to offer prices for energy as close as possible to their fuel and operating costs and to perform reliably.
- FCM: ISO-NE procures resources in support of long-term resource adequacy through the FCM. The FCM is designed with the goal of ensuring the system has sufficient resources to meet forecasted future demand by paying resources to be available to meet the projected demand for electricity three years out and operate when needed, including during shortage events, once the capacity commitment period begins. The amount of capacity needed to meet the forecast regional electricity demand and reserve requirements – *i.e.*, ICR – as described above, is determined through planning assessments based on long-term demand forecasts, accounting for, among other things, unplanned system conditions and weather uncertainties .<sup>30</sup>

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<sup>30</sup> The recently-held 12<sup>th</sup> Forward Capacity Auction (“FCA-12”) acquired about 30,000 MW of generating capacity, and about 3,600 MW of energy-efficiency and demand-reduction measures.

- Ancillary Services: ISO-NE procures ancillary services that are necessary for ensuring short-term reliability. Through the Regulation Market,<sup>31</sup> ISO-NE compensates resources instructed by ISO-NE to increase or decrease output moment-by-moment to balance the system frequency and New England’s area control error (“ACE”). The FRM keeps capacity in reserve and available to provide electric energy within ten or thirty minutes to ensure the system is able to withstand adverse events. Pursuant to the OATT, ISO-NE also compensates resources for maintaining reactive power or VAR capability necessary for ISO-NE system operators to maintain transmission voltages within an acceptable range, and compensates specific generating plants at key locations for their blackstart capability, which is needed to restart the transmission system following a blackout.<sup>32</sup>

### **3. Operating the Power System Reliably**

As the RTO, ISO-NE is responsible for ensuring a reliable supply of electricity to meet demand at all times. In other words, ISO-NE must maintain the precise balance of supply and demand required to keep the lights on and avoid uncontrolled system separations or cascading power outages that can trigger widespread blackouts. To meet this mandate, ISO-NE operates the system reliably (*i.e.*, so that it is able to withstand pre-defined disturbances without resulting in the cascading failure of the system), and in strict adherence to standards set by NERC and NPCC.

To fulfill this critical role, ISO-NE’s NERC-certified system operators consider and prepare for a large number of variables that can at any moment affect the production and flow of power across the system. To that end, system operators conduct operational readiness assessments and develop Transmission Operating Guides as elements are added to, or removed from, the system to foresee issues that may arise and identify appropriate actions to maintain

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<sup>31</sup> See Tariff at § III.14.

<sup>32</sup> See OATT at Schedule 2 and 16.

resilience should an event unfold. In addition, to ensure consistent, reliable operation of the grid, ISO-NE develops and follows detailed Operating Procedures that incorporate NERC and NPCC standards. The Operating Procedures outline certain actions ISO-NE takes to manage the power system, including procedures specifically designed to improve information and further ISO-NE's understanding of generation fuel availability in anticipation of and during emergency conditions, such as extreme cold weather conditions. ISO-NE develops short-term regional and zonal load forecasts to help assess the amount of energy needed, and manage the power system through a variety of conditions. ISO-NE also tracks weather and monitors power plants for unexpected outages and transmission lines for overloads across the entire Control Area.

To ensure the moment-to-moment reliability of the power system, ISO-NE system operators perform reliability assessments and real-time security studies to ensure that system resources can be re-dispatched to address contingencies and adhere to mandatory requirements for maintaining operating reserves that can be called on to produce electricity should a contingency occur. ISO-NE system operators employ real-time emergency procedures to respond to conditions that can impact ISO-NE's ability to maintain the required amount of operating reserves available on the system (*e.g.*, unexpected high demand due to extreme cold weather, an unusual number of generators out of service due to equipment failure, fuel constraints or environmental restrictions). These procedures outline the specific actions ISO-NE takes to keep the power system operating reliably. These actions include steps that can progress from emergency operating actions of which the general public would not even likely be aware, to actions that are visible to the public, such as requests for voluntary energy conservation. As a last resort, ensuring the reliability of the power system can require involuntary load-shedding.<sup>33</sup> Should a partial or total shutdown of the New England power system occur, ISO-NE has a robust system restoration plan in place to programmatically restore the system.

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<sup>33</sup> For example, the Northeast Blackout of 2003 required limited involuntary load shedding.

## **B. New England's Unique Fuel-Security Challenges**

### **1. The New England System and the Changing Resource Mix**

As described above, a reliable power system requires a reliable supply of the fuels used to generate electricity. The New England region, however, does not have indigenous fossil fuel extraction, refinement, or large-scale storage such as the underground storage found elsewhere in the country. Therefore, the region's generating fleet primarily relies on fuels imported from elsewhere in the United States and Canada and from overseas by ship, truck, pipeline or barge. Because New England depends on imported fuels to produce power, acquiring fuel when needed on demand to generate electricity is critical for the region's power system reliability and therefore its resilience. This fuel security problem is particularly acute with natural gas, on which the regional power system is increasingly dependent for natural gas-fired generation, but the corresponding investments in natural gas-fuel infrastructure to meet the increasing power sector demand for gas have not been made.

For context, in 2000, oil- and coal-fired power plants produced 40% of the electricity generated in New England, while natural gas fueled just 15%. The steadily increasing efficiency of gas turbine and combined cycle technology, coupled with ever-more stringent emissions policies that benefit gas relative to other fossil fuels, have led to the development of over 16,000 MW of new, natural gas-fired power plants in New England over the past fifteen years. At the same time, the significant increase in domestic shale gas production has resulted in low-cost natural gas, which is available for power generation most of the time outside of very cold winter conditions. Because New England dispatches the lowest-cost resources first to meet demand, natural gas became the most economic and therefore dominant fuel used to produce electricity in the region when there are no gas-fuel infrastructure or delivery constraints. By 2016, the proportion of energy produced by natural gas-fired generation increased to 49%. Coal and oil dropped to only 3% of annual electricity generation, even though those resources still made up

nearly 30% of the region's total generation capacity.<sup>34</sup> Natural gas-fired generation in New England's capacity mix is expected to grow from approximately 45% in 2017 to 56% in 2026.<sup>35</sup>

In regions that have an abundance of natural gas-fuel infrastructure (including storage capability), additional demand for natural gas for power generation may not necessarily be an immediate concern. New England's five interstate pipelines were built to meet the peak demand needs of the local natural gas distribution utilities that contracted for the gas-fuel infrastructure capacity. Because of growth on the end use demands of residential, commercial and other retail customers on the gas utilities' systems, the capacity is fully utilized by their firm shippers increasingly often, especially during cold winters. During most months of the year, the existing capacity is sufficient for both the local gas utilities and the natural gas-fired power plants, but increasingly, it is challenging to meet all of the demand during the cold weeks of the year.<sup>36</sup> As a result, natural gas-fired power plants – which typically buy surplus capacity released by local gas utilities on the secondary market<sup>37</sup> – may not be able to acquire natural gas when they need to run.

Limitations on the gas-fuel infrastructure capacity available for natural gas-fired generators also highlight the importance of dual-fuel generating capability in the region, which allows the region to rely on that capability if the dual-fuel generator cannot obtain its primary natural gas supply (or if the price of gas is higher than oil). However, the region's existing dual-fuel capability is limited, and environmental restrictions have made permitting and operating such oil-fire capability increasingly difficult. In addition, as a result of economic and

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<sup>34</sup> See 2017 RSP at 98.

<sup>35</sup> See *id.*

<sup>36</sup> Because of the restructuring of the industry (contrasted with vertically integrated regions, New England is almost completely divested), and the incompatibility between the gas pipeline model (which requires long-term commitments) and the economic circumstances for merchant generators in the competitive wholesale markets, merchant generators have not been willing to enter into the contracts to build or expand the gas-fuel infrastructure.

<sup>37</sup> In New England, the utility sector is almost completely divested. This means that regulated transmission owning companies that also operate electric distribution companies and also often have local distribution gas affiliates do not own or operate electric power generation. Therefore, procuring long-term firm gas capacity for electric power generation is not a function under the regulated companies that can recover such costs in rates, but is rather procured by market rate resources.

environmental factors, New England continues to see the retirement of large resources with significant on-site fuel in the form of oil, coal, and nuclear power plants, which further exacerbates the region's dependence on natural gas-fired generation. Over 4,600 MW or about 16% of the region's non-gas generating capacity will have retired by 2021, and another 5,000 MW of coal- and oil-fired generation are at risk for retirement in coming years.<sup>38</sup> However, as experienced during the recent cold weather stretch, while aging coal- and oil-fired resources only run a small fraction of the time throughout the year, combining to produce only 3% of New England's electricity in 2017, they are critical resources during periods when demand is peaking and gas-fuel infrastructure is sharply constrained. As noted above, in those situations, the region becomes dependent on coal- and oil-fired resources to continue to generate sufficient electricity to serve load.

Renewable resources (wind, solar, energy efficiency, and energy storage) are rapidly expanding on the New England power system. For example, wind energy resources have grown significantly from 375 MW of nameplate capacity in 2011 to more than 1,300 MW today, and approximately 8,600 MW of more on- and off-shore wind resources are proposed.<sup>39</sup> The significant increase in renewable resources, such as wind resources, in New England has helped. However, it will not allow the region to significantly reduce the current need for on-site storage fossil fuels, or supplant the need for enhanced fuel infrastructure absent a much greater investment in renewable resources along with substantial advances in storage technologies and significant investment in transmission infrastructure to move the power to consumers from the weak-grid areas of the system where half of the proposed wind resources would be sited. While renewable resources help, their output depends on weather and time of day, and they require fast-starting, flexible resources to balance the system (the sort of services provided by modern natural gas-fired generators). Measures to reduce wholesale demand, such as energy efficiency investments and behind-the-meter solar installations have steadily increased. In particular, energy efficiency investments yield tremendous benefits for the region by reducing demand for power from the regional power system during both the peak and winter season.

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<sup>38</sup> See OFSA at 13.

<sup>39</sup> See State of the Grid 2018 Presentation at 17.

## 2. Mitigating Measures to Address Reliability in the Short-Term

New England has a history, dating back to 2004, of engaging in efforts with regional stakeholders to deal with its concerns about the region's increasing dependence on New England's already-burdened natural gas-fuel infrastructure. The region's fuel-security risk, in the context of increased dependence on natural gas, became evident during the January 2004 "Cold Snap," when the region experienced extremely low temperatures, sustained high winds, and particularly high demand for electricity, prompting concerns about market and system performance during severe cold weather conditions. The 2004 "Cold Snap" exposed vulnerabilities of the New England power system, especially with regard to capacity limitations on the natural gas-fuel infrastructure and the unavailability of gas transportation for non-firm customers like gas-fired generators within New England. Such upstream contingencies – *i.e.*, the industries' fuel-delivery systems – are beyond ISO-NE's authority. As such, ISO-NE, with regional stakeholder support, took a number of actions in the form of market design changes and operating procedures in effort to address the reliability concerns associated with the region's dependence on natural gas with limited capacity and resource performance issues.

On the market side, ISO-NE took major steps to increase efficiency and improve gas-electric coordination to address the challenges posed by the region's constrained natural gas-fuel infrastructure. Some of these initiatives include:

- DAM Timing Changes: In 2013, ISO-NE implemented changes in the timing of the DAM and Reserve Adequacy Analysis ("RAA") schedules to allow for bidding to end earlier and ISO-NE to commit resources earlier than under the previous configuration.<sup>40</sup> These changes were intended to give generators more time to procure natural gas by better aligning the electricity and natural gas markets timelines. ISO-NE now publishes the results of the DAM by 13:30 (as compared to 16:00 under the former rules), giving generators more time to nominate the gas they need to run the following operating day.

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<sup>40</sup> See *ISO New England Inc., et al.*, 143 FERC ¶ 61,065 (2013).

- Energy Market Offer Flexibility Changes: In 2014, ISO-NE implemented energy market offer-flexibility enhancements to allow Market Participants to modify their offers to supply electricity on an hourly basis within the operating day.<sup>41</sup> These changes were intended to improve resources' ability to better reflect changing fuel costs and opportunity costs in offers, especially during periods of high fuel volatility, improving market pricing and incentives to perform.
- Pay For Performance Rules: Through the Pay For Performance suite of changes filed and approved in 2014, ISO-NE tightened the Shortage Event trigger in FCM to ensure the Shortage Event “triggered” earlier in a period of reserve deficiency, and increased incentives for resources provide energy and reserves during scarcity conditions.<sup>42</sup> While, this is a “no excuses” performance requirement, measuring actual performance regardless of facility outage state or reason for outage, including resources offline by reason of economics, the incentives contained within this market structure are phased in over multiple years. These changes give resources incentives to undertake all cost-effective investments that enable them to perform when they are needed most, with the potential that the significant rewards and penalties will cause generators to respond with improved fuel arrangements. The Pay For Performance rules will take effect in the Capacity Commitment Period beginning on June 1, 2018, with an initial performance rate that is less than the final performance rate.
- Winter Reliability Program: Prior to the winter 2013/2014, ISO-NE instituted a short-term Winter Reliability Program (“WRP”) to address fuel security concerns during the winter season as a stop-gap until the more permanent Pay For Performance

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<sup>41</sup> See *ISO New England Inc., et al.*, 147 FERC ¶ 61,073 (2014). For background, under the former rules, Market Participants were permitted to change Supply Offers (*i.e.*, modify offers used in the DAM) only during a period beginning when the DAM results were published and ending at 2 pm on the day before the operating day. No offer changes were permitted during the operating day.

<sup>42</sup> See *ISO New England Inc., et al.*, 147 FERC ¶ 61,172 (2014), *order on reh'g*, 153 FERC ¶ 61,223 (2015).

rules.<sup>43</sup> Although the WRP evolved slightly since its initial structure, its objective remained the same – namely, to create a financial incentive for the physical procurement of oil within the region prior to December 1, to secure contracts for LNG, and to create a winter-specific active demand-response program. This year’s WRP supported the procurement of roughly three million barrels of oil eligible for compensation under the program. This program has been a short-term stop-gap means of attempting to address winter fuel-security concerns and expires with the end of this winter season given the Pay For Performance rules will take effect in June.

On the operations side, ISO-NE developed Operating Procedures, systems and tools to improve coordination, communications, intelligence and operations during cold weather conditions. For example, ISO-NE developed new Operating Procedures designed to improve information on generator availability during cold weather conditions.<sup>44</sup> These procedures ask generators to report their anticipated availability to ISO-NE, including details on their ability to procure fuel, maintain oil inventories, and any physical limitations of their generating units. ISO-NE also enhanced communications with the regional gas industry to improve the ability to detect conditions on the gas system that could affect the availability of gas-fired generators; specifically, ISO-NE was able to modify its Information Policy in January 2014 following the Commission’s explicit grant of authority in Order No. 787<sup>45</sup> for interstate natural gas-fuel infrastructure and electric transmission operators to share non-public information for the purpose of promoting reliable service and operational planning.<sup>46</sup> These modifications have facilitated effective, non-public operational-related discussions about specific generators with gas-fuel infrastructure operators. In addition, ISO-NE developed decision-support tools for System

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<sup>43</sup> See *ISO New England Inc., et al.*, 148 FERC ¶ 61,179 (2014), *clarification granted*, *ISO New England Inc., et al.*, 150 FERC ¶ 61,029 (2015), *reh’g denied*, *ISO New England Inc., et al.*, 151 FERC ¶ 61,052 (2015) (regarding the 2014/2015 Winter Reliability Program). See also *ISO New England Inc., et al.*, 144 FERC ¶ 61,204 (2013), *reh’g denied*, *ISO New England Inc.*, 147 FERC ¶ 61,026 (2014) (regarding 2013/2014 Winter Reliability Program).

<sup>44</sup> See Operating Procedure No 21 Energy Inventory Accounting and Actions During an Energy Emergency, [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op21/op21\\_rto\\_final.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op21/op21_rto_final.pdf) (“OP-21”).

<sup>45</sup> *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 145 FERC ¶ 61,134 (2013) (Order No. 787”).

<sup>46</sup> *ISO New England Inc.*, 146 FERC ¶ 61,159 (2014).

Operators. One such tool, called the Gas Usage Tool, allows ISO-NE to estimate the amount of natural gas available for electric generation each operating day. This is accomplished by estimating the demand for gas by industrial and local gas distribution companies' customers, as well as gas-fired generators, compared to the capability of the natural gas pipeline system, including LNG injections into the regional gas-fuel infrastructure.

The measures described above have greatly helped ISO-NE's ability to manage operational situations where fuel delivery to region has become constrained. However, based on the analysis of future trends described below, as well as ISO-NE's continued experience with operations of a fuel-constrained system, it is evident that more work will need to be done on the issue of fuel security in the region.

### **3. Current Trends Increasing Fuel-Security Challenges**

In the Resilience Order, the Commission recognizes that there are a "variety of economic, environmental and policy drivers that are changing the way electricity is procured and produced," and these drivers present new challenges to the reliability of each region's electric system and may impact its resilience.<sup>47</sup> This is certainly the case in New England.

ISO-NE has continued to examine matters related to fuel security in the region. In particular, ISO-NE has been observing ever-increasing difficulties in the permitting and siting of dual-fuel resources in the region, the performance of the generation fleet and fuel supply chain during cold weather periods, and the evolution of state policies. Thus far, with on-site fuel inventories procured with the help of the WRP and other measures described above, ISO-NE has been able to operate the New England power system reliably during severe winter conditions without the need to invoke emergency procedures. Operating experiences in recent winters and current industry trends changing the makeup of the New England power system, however, indicate the region's fuel-security challenges are likely to intensify.

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<sup>47</sup> Resilience Order at P 17.

The most significant industry trends contributing to New England's fuel-security risk are the region's increasing use of natural gas-fired generation relying on "just-in-time" fuel deliveries, and the retirement of oil, coal, and nuclear power plants due to economic forces and environmental-regulation costs. As noted above, over 4,600 MW of the region's current generating capacity will have retired by 2021, and more are signaling a desire to leave the market. While coal-fired and oil-fired plants do not frequently run in the currently prevalent fuel competitive dynamic, they now act as critical resources on cold weather days when the natural gas-fuel infrastructure serving New England is constrained and fuel for natural gas-fired generators becomes expensive or unavailable.

During the 2017/2018 Cold Weather Stretch, heating demand for gas during severe winter conditions utilized essentially all of the capacity of the region's constrained gas-fuel infrastructure resulted in substantially higher New England natural gas and (concomitantly) higher wholesale electricity prices, leading (temporarily) to oil and coal power plants operating. With oil-fired generation operating at or near full capacity, oil supplies and emissions allowances at power plants around the region began to rapidly deplete over the two-week period, making system operations extremely challenging and significantly increasing the reliability risk to the system. Fuel replenishment takes time to arrange for the fuel, transportation, and then delivery (by barge, truck, or pipeline). These logistics can be hindered during the winter due to the type of fuels available at the oil terminals, weather conditions affecting transportation, including icing of waterways, and availability of trucks or barges as they may be transporting home heating oil.

While dual-fuel capability can help maintain reliability when gas is unavailable or at a premium, this capability is limited in the region, and state and federal environmental restrictions and goals make permitting additional capability problematic and can limit operation of existing oil-fire capability. Like units running primarily on oil, the ability of units with dual-fuel capability to run on oil may be limited by the amounts of fuel stored on-site, and can be further affected by the timing of fuel consumption and replenishment, or for environmental reasons, as emissions restrictions on burning oil are tightening. As noted earlier, significant increases in renewable resources, which are also replacing retiring resources, help reduce the demand for

energy and the fuels used to generate it, but it will not result in the region moving significantly away from fossil fuels for the foreseeable future.

The shift away from generators with on-site fuel to natural gas-fired generators relying on “just-in-time” fuel delivery has further exposed the limitations of New England’s existing fuel infrastructure and heightened the region’s fuel-security risk. While New England is meeting its summer peak megawatt resource adequacy needs for capacity with the mechanisms that are in place today, from an energy availability standpoint, the system’s adequacy is being challenged by fuel-security risk as the generation fleet shifts from generators with on-site fuel to generators relying on “just-in-time” fuel. Given its responsibility to ensure that the wholesale electric power system continues to provide the region’s consumers with a reliable supply of electricity through these transitions, ISO-NE conducted the OFSA to assess the potential operational impacts the regions’ fuel-security risk can pose in the future if current trends continue.

As further discussed below, the results of the analysis shed light on New England’s fuel-security challenges and indicate further action is warranted to address those challenges.

#### **4. The OFSA Identifies Major Fuel-Security Risk in Wide-Range of Scenarios Examined**

In January 2018, ISO-NE issued the OFSA report, its first operational analysis specifically designed to examine how a wide range of hypothetical combinations of generating resources and fuel mixes could impact reliable operation of the region’s power system during a future winter period. The OFSA differs from all ISO-NE previously-conducted studies in three key ways: first, it is a deterministic analysis focused on the availability of *energy* over the course of an entire winter period, rather than looking at capacity availability on a single winter peak day; second, it quantified operational risk in terms of operational metrics by measuring energy shortfalls implemented through emergency actions pursuant to ISO-NE’s OP-4 and OP-7, which are used today to measure system stress; and, third it is an operational study focused on reliability.

The OFSA studied the effects of 23 hypothetical future resource and fuel mix scenarios reflecting ISO-NE's experience and regional trends, as well as outages of several key energy facilities during the entire winter of 2024/2025 to assess whether enough fuel would be available to meet demand under a wide range of potential conditions, and quantified the fuel-security risk in each scenario. The study targeted the 2024/2025 winter based on the levels of consumer demand experienced in the 2014/2015 winter.<sup>48</sup> Winter 2014/2015 served as a baseline because, while it did not have the coldest days recorded in the past ten years, it had the most sustained consecutive cold days as measured by heating-degree days.<sup>49</sup> Thus, it provided a wider perspective on the cumulative use of oil and LNG inventories over 90 days and the need to replenish these inventories as cold weather persists. If the region experienced colder winters than 2014/2015, as is possible, the number and duration of energy shortfalls found in the OFSA would be magnified.

For each scenario, the OFSA calculated whether sufficient fuel, including natural gas, LNG and oil, would be available for the system to satisfy electricity demand and maintain power system reliability throughout the 2024/2025 winter by assuming the five resource variables noted above (*i.e.*, resource retirements; LNG availability; oil tank inventories; imported electricity; and, additional renewable resources). The study assumes no coal-fired generation and no additional natural gas supply infrastructure (beyond the incremental expansion already underway), as ISO-NE does not anticipate further development of natural gas infrastructure during the time period of the analysis. The hypothetical cases, while not predictions, seek to illustrate a range of potential risks that could confront the New England power system with fuel and energy constraints during winter.

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<sup>48</sup> The hourly demand levels from winter 2014/2015 were adjusted to reflect the ISO's forecast for slightly higher net peak demand in extreme winter conditions in 2024/2025. The conditions experienced in the recent 2017/2018 Cold Weather Stretch were not used as a baseline as those took place after the study was completed. However, as noted in response to the Resilience Order questions below, ISO-NE used the analysis from the OFSA to, among other things, help improve overall situational awareness in preparation for the recent experience.

<sup>49</sup> See OFSA at 21.

The OFSA contains significant detail on the inputs and results of the 23 hypothetical resource and fuel-mix combinations examined. At a high level, the cases included:

- 1 reference case, which incorporates each of the five key variables at levels that can reasonably be expected given current trends, serving as a baseline for comparison with other scenarios (“Reference Case”);
- 8 single-variable cases that increase and decrease the level of just one key variable to assess its relative impact in each case (“Single-Variable Scenarios”);
- 2 boundary cases that illustrate what would happen if either all the favorable or unfavorable variables were realized simultaneously (“Boundary Cases”);
- 4 combination cases that combine the key variables to illustrate their combined effects on fuel security (“Combination Scenarios”); and,
- 8 outage cases that illustrate the effects of a winter-long outage of major energy facilities in the region (“Outage Cases”).<sup>50</sup>

These hypothetical cases illustrate the range of potential risks to the power system as fuel and, therefore, energy production capability, become further constrained over the course of coming winters given current trends.

The OFSA found that energy shortfalls due to *inadequate fuel* would occur with almost every fuel-mix scenario (including, full recognition of new renewable resources) in winter 2024/2025, requiring frequent use of emergency actions to protect the bulk power system. In other words, in almost all modeled future resource and fuel-mix combinations, the power system was unable to meet electricity demand and maintain reliability without some degree of emergency actions. The number of hours of emergency actions should not be interpreted as predictions, but rather as an indicator of a system stress. Taken together, the study results

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<sup>50</sup> The outage scenarios reflect the consequences of four possible high-impact events involving the outages of the following key facilities in New England: (1) a compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and restricting fuel to about 7,000 MW of generation for an entire winter; (2) the loss of Millstone Nuclear Station in Connecticut, one of the region’s remaining two nuclear stations in the study year, eliminating 2,100 MW of baseload power; (3) the loss of the Canaport LNG import and regasification facility in New Brunswick, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems; and, (4) a disruption of the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby 1,700 MW Mystic 8 and 9 combine-cycle generators, as well as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems and the local gas utility’s distribution system. See OFSA at 43.

suggest that New England could be headed for significant levels of emergency actions, particularly during major fuel or resource outages. These operational risks may be further compounded by unknown logistical challenges for fuel procurement and transportation that can be experienced during high-demand cold weather events.

The key conclusions suggested by the study's findings are:

- Outages – The region is vulnerable to the season-long outage of any of several major energy facilities considered in the Outage Cases. An extended outage of any of the key facilities would result in frequent energy shortages that would require frequent and long period of rolling blackouts. An outage at a natural gas pipeline compression station would have the most severe impact.
- Stored Fuels – Future power system reliability will be heavily dependent on the region importing and storing enough LNG. However, demand for LNG is growing as pipeline capacity remains the same and gas fields in Atlantic Canada are depleting. In addition, electricity imports from Quebec are uncertain as they may be needed in the Quebec area during cold winter conditions. More dual-fuel capability is also a key reliability factor, but permitting for construction and emissions is difficult.
- Logistics – The timely availability of fuels of all types will be critical, highlighting the importance of fuel-delivery logistics. Refilling oil and LNG tanks at some point over the course of a 90-day winter may not be a problem, but when cold snaps and winter storms follow each other in quick succession, replenishing fuel tanks quickly is of paramount importance. Such timely replenishing can be challenging, however, given the difficulty of predicting far enough in advance how much LNG or oil will be needed to ensure trucks and LNG tankers will arrive when needed, even assuming that the necessary orders are placed.
- Risk Trends – The modeled scenarios indicate that trends affecting New England's power system may intensify the region's fuel-security risks. These trends include

increasing resource retirements; the growth in natural-gas fired generation; growing natural gas demand from local gas utilities serving the heating sector; and an increase in renewable resources with variable output. The Reference Case, as described previously, required hundreds of hours of OP-4 actions and depletion of operating reserves, and more than a dozen hours of load shedding. On balance, the study revealed that fuel-security risks are trending in the negative direction, even in scenarios with increased amounts of LNG, renewables and imports.

- Renewables – More renewable resources can help lessen the region’s fuel-security risk depending on the type and quantity,<sup>51</sup> but are likely to drive coal- and oil-fired generator retirements. Accordingly, more LNG will be needed to counteract the loss of stored fuels.
- Positive Outcomes – More LNG, electricity imports, and renewables can help minimize system stress and maintain reliability, but to attain higher levels, transmission expansion and dependable delivery arrangements for LNG and imports will be needed.

The OFSA provides additional clarity to New England’s unique fuel-security challenges. The study results help ISO-NE and regional stakeholders compare different possible future fuel scenarios so that discussions can occur about the level of fuel-security risk tolerance, and together develop the appropriate long-term solution.

New England’s efforts addressing the region’s fuel-security challenges since the 2004 Cold Snap, including the OFSA and its role in identifying fuel-security risk, as well as the experience gained during the 2017/2018 Cold Weather Stretch, form the primary basis for some of the responses below.

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<sup>51</sup> For example, offshore wind tends to blow more steadily which can coincide with winter conditions, but it will not be on line for many years; solar facilities do not help meet winter peak demand.

### III. RESPONSES TO SPECIFIC QUESTIONS

#### A. The Commission's Understanding of Resilience is Consistent with ISO-NE's Consideration in Assessing the Reliability of the Bulk Power System

In assessing the reliability of the New England bulk power system, ISO-NE considers two key factors: security (*i.e.*, the system's ability to withstand unexpected disturbances, such as a loss of system elements) and adequacy (*i.e.*, the system's ability to supply the energy required to meet the demand, accounting for scheduled and reasonable expected unscheduled outages of system resources).<sup>52</sup> For the bulk power system to be resilient – *i.e.*, able to withstand and reduce the magnitude and/or duration of disruptive events – both of these aspects of reliability need to be addressed. ISO-NE's work in planning, markets, and operations to help ensure the region has the power resources and transmission facilities necessary to meet demand and reserve requirements results in a bulk power system that has many attributes of a resilient system.

#### B. Responses on How ISO-NE Assesses Threats to Resilience

- a. What are the primary risks to resilience in your region from both naturally occurring and man-made threats? How do you identify them? Are they short-, mid-, or long-term challenges?*

The most significant challenge to the resilience of the New England bulk power system is fuel-security – *i.e.*, ensuring that power plants have or will be able to obtain the fuel they need to produce the power required to meet the system's demand and reserves, particularly in winter.

Fuel-security concerns are not new to New England. ISO-NE's attention to the risk related to fuel security in the context of increased reliance of natural gas became prominent as a result of 2004 Cold Snap, when New England experienced extremely low temperatures and reached the all-time peak winter demand for electricity, exposing concerns about market and system performance during severe cold weather. The conditions exposed vulnerabilities of the New England power system, especially with regard to capacity limitations on the natural gas pipeline system and the availability of gas transportation for New England's gas-fired generators.

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<sup>52</sup> See NPCC Glossary (defining "Reliability").

During that cold snap a significant number of natural-gas fired generators were unavailable due to gas-fuel infrastructure constraints, economic outages, and operational issues.

Since that time, ISO-NE, in conjunction with regional stakeholders, has undertaken numerous efforts to address these concerns. For example, ISO-NE has made significant changes in the energy, reserves and capacity markets aimed at improving generator performance and gas-electric coordination, and thereby improve system reliability and market efficiency. In addition, ISO-NE has developed Operating Procedures and enhanced operational and forecasting systems and tools to mitigate fuel-security challenges and ensure shorter-term reliability is maintained. While these improvements have helped, ISO-NE's operational experience in recent winters, including the 2017/2018 Cold Winter Stretch, and current industry trends indicate the New England power system is on a path toward greater fuel-security risk and further action is needed.

The prevalent industry trends contributing to the region's fuel-security risk are as follows. First, the regional power system is increasingly reliant on natural gas for power generation; however, the existing natural gas-fuel infrastructure is not always adequate to deliver all of the gas needed for both heating and power generation in the winter. Second, environmental restrictions and goals are making it more difficult to permit additional dual-fuel generating capability, which helps when natural gas is not available, and emissions restrictions on burning oil are tightening, which further constrains the operation of the region's existing limited dual-fuel capability. Third, the region's older oil, coal, and nuclear generators with fuel on-site, which are critical to reliability when natural gas is not available, are becoming less economically competitive and may seek to retire before the region has addressed the fuel-delivery constraints, or added sufficient alternative resources to replace them.

Although the region is meeting its peak megawatt resource adequacy requirements for *capacity* with the market mechanisms that are in place today, this shift from generators with on-site fuel to natural gas generators relying on "just-in-time" fuels (or, even, more variable fuels, such as wind and solar), is challenging the system's adequacy from an *energy* availability standpoint. Any limitations or disruptions in the fuel delivery supply chain have an immediate impact on the operation of the power system. Accordingly, ISO-NE and regional stakeholders

need to consider appropriate measures to assess the system’s adequacy in terms of energy given the change in resource mix.

As described above, ISO-NE conducted the OFSA to understand and quantify the region’s fuel-security risk. The OFSA assessed how the system could be operated with the fuel available under a wide range of resource scenarios during an entire cold winter in 2024/2025. Examining fuel availability over an entire winter period in a wide range of hypothetical cases, reflecting potential future resource fuel-mix combinations in New England, provides a perspective on the relative levels of fuel-security risk that could manifest, depending on how the New England power system evolves.

One of the major conclusions of the study is that the impacts of current trends affecting the New England power system’s reliability are moving in a negative direction. All but one of the 23 scenarios examined (*i.e.*, the most favorable future resource-mix combinations) show that the regional power system could frequently experience some degree significant system stress, requiring operators to employ emergency procedures in order to maintain reliability. In 19 of the 23 scenarios, some level of load shedding was required to maintain system balance. While not predictions of the future, the results show that, in most of the future power system hypotheticals studied, sufficient levels of fuel that are necessary to enable resources to perform will not be available throughout the entire winter. The resulting energy shortfalls – measured using operational metrics – would require a range of operating procedures and emergency actions, up to and including, load shedding.

The OFSA results also show that the region is most vulnerable to the winter-long outage of any of the key energy facilities considered in the Outage Cases, and particularly vulnerable to the reduction in natural gas supply in New England that could result from an outage at a particular natural gas pipeline compressor station. While the OFSA does not specify the probability of each scenario examined (as it is a deterministic analysis), it qualitatively recognizes that the Outage Cases represent high-impact, low-frequency (“HI/LF”) risks. The probability of losing any one of the key energy facilities considered in the Outage Cases for an

entire winter period is low, but the impact would be high should the event unfold given the amount of energy each of those key facilities injects into the system.

***b. How do you assess the impact and likelihood of resilience risks?***

ISO-NE assesses the impacts of identified risks by gathering all of the information and data necessary, including direct operational observations and industry feedback, and performing comprehensive analysis to understand the potential impacts of the risks. The OFSA provides an example of how ISO-NE assesses risk and quantifies potential impacts of identified risks to the New England power system's resilience, outside of system planning and operational assessments.<sup>53</sup>

ISO-NE's assessments in preparation for the 2017/2018 Cold Weather Stretch,<sup>54</sup> also provide an example of how ISO-NE assesses and manages risks in anticipation of and during extreme weather events to ensure reliable power system operation.

As described in Part II.A, ISO-NE performs operational readiness assessments to foresee issues that may arise and identify appropriate actions to maintain reliability should an event unfold. In preparation for the 2017/2018 Cold Weather Stretch, ISO-NE initiated a review of the capacity adequacy of the system, taking into account the unavailability of gas-only units due to cold weather, weeks in advance. Specifically, in advance of the 2017/2018 Cold Weather Stretch, when weather forecasts were showing significantly lower than expected temperatures for a longer than expected duration, ISO-NE forecasters performed assessments of unit availability and the expected demand, imports, and weather to improve overall situational awareness and identify any potential problems. In addition, pursuant to OP-21, ISO-NE requested fuel surveys from owners of oil-fired power plants seeking information on their oil inventories to analyze the

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<sup>53</sup> The details regarding the scenarios examined, the inputs and assumptions reflected in the models for each case, and the methodology used to quantify each case's fuel-security risk are documented in the OFSA report submitted as part of this response. *See* OFSA at 18-31.

<sup>54</sup> During the 2017/2018 Cold Weather Stretch average temperatures in all major cities in New England were below normal for at least 13 *consecutive* days, of which 10 days averaged more than 10°F below normal. This is similar to the weather experienced in the 2014/2015 winter, which was used as the baseline for the OFSA. *See* 2017/2018 Cold Weather Stretch Presentation.

oil inventories with the units' expected run times and assess whether the units burning oil would be able to continue doing so until the extended cold weather diminished.

Each day, ISO-NE analyzed the fuel availability to meet the daily operating plan based on generators' DAM and RAA commitments. ISO-NE also generated a fuel report twice a day due to the overlapping gas-electric day, to monitor natural gas-fuel infrastructure schedules and, if dual-fuel, which fuel, oil or gas. The gas schedule was then compared to how much gas the generators had scheduled versus how much gas the generators would need to meet their RAA commitment. ISO-NE then used the Gas Usage Tool to assess the availability of natural gas for any additional commitments.

Throughout the extended cold weather, ISO-NE continued monitoring oil inventories and communicated with the Market Participant to determine if their respective replenishment plans would get us through the cold weather. ISO-NE continuously assessed whether oil units would run out of fuel before the cold weather diminished. Based on the information gained from these analyses, ISO-NE adjusted the dispatch to bring on additional natural gas-fired generators for the days gas was available to the generators in order to conserve oil and prevent certain oil-only generators from running out of oil, which, ultimately, allowed the region to get through the cold weather stretch.<sup>55</sup>

Operational measures implemented after the 2004 Cold Snap helped ISO-NE maintain overall situational awareness before, during, and after the 2017/2018 Cold Weather Stretch. For example, ISO-NE held numerous conference calls with other NPCC Reliability Coordinators, all six New England Local Control Centers, and the Northeast Gas Association/Gas Supply Task Force ("NGA/GSTF") members. With NPCC Reliability Coordinators, ISO-NE system operators reviewed expected weather and peak loads for the current and next day, expected MW surplus above operating reserve requirements, expected interchange schedules, and the conditions of natural gas supply and fuel oil inventory. System operators also discussed this information with the New England local control centers. With the NGA/GSTF members, system

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<sup>55</sup> See 2017/2018 Cold Weather Stretch Presentation.

operators discussed the overall conditions of each interstate pipeline and LNG supplying New England. In addition, system operators maintained daily communications with interstate pipeline operators. ISO-NE also initiated twice-weekly fuel surveys of oil-fired generation, and increased the periodicity to daily based on system conditions during and after the cold weather stretch to increase situational awareness.

The 2017/2018 Cold Weather Stretched experience underscored some of the challenges to reliability posed by the fuel-security risk, such as the fuel-related logistics. While the system operated reliably through the extended cold weather period, it relied heavily on oil-fired generators to meet load and reserves, introducing the replenishment and emissions restrictions concerns identified in the OFSA, and highlighting the importance for fuel inventories to be sufficiently replenished in winter. New England imports almost all of its fuel, so delivery logistics are a fundamental factor on reliable operations during winter. Winter storms can delay deliveries of oil by road, and LNG by sea; tanker truck drivers can run up against restrictions on driving time; heating oil customers get priority for deliveries; and oil deliveries can be delayed when the rivers freeze or there are not sufficient oil barges when the entire East Coast is seeking oil deliveries. In addition, some oil-fired generators were nearing their annual emissions limits. As such, their ability to operate during the remainder of the year will be limited absent waivers of the emissions limits to maintain power system reliability will be limited.

- c. Please explain how you identify and plan for risks associated with high-impact, low-frequency events (e.g., physical and cyber attacks, accidents, extended fuel supply disruptions, or extreme weather events). Please discuss the challenges you face in trying to assess the impact and likelihood of high-impact, low-frequency risks. In addition, please describe what additional information, if any, would be helpful in assessing the impact and likelihood of such risks.*

Identification of HI/LF Risks:

ISO-NE participates, reviews and evaluates industry work to help identify risks associated with high-impact, low-frequency (“HI/LF”) risks. Examples of industry work include the June 2010, NERC and DOE report, titled “High-Impact, Low-Frequency Event Risk to the

North American Bulk Power System,”<sup>56</sup> and the NERC Severe Impact Resilience Task Force and Cyber Attack Task Force report from May 2012.<sup>57</sup> Studies, such as the ones identified here, provide insight for ISO-NE to perform internal assessments and improve operational procedures and practices.

Significant work is already underway with respect to HI/LF events, such as cybersecurity, physical threats, and geomagnetic disturbances. Indeed, as the Resilience Order states, “the Commission has conducted significant work to address bulk power system reliability standards, including its continued work on Critical Infrastructure Protection (“CIP”) standards to protect the system against cybersecurity and physical security threats, as well as geomagnetic disturbances.”<sup>58</sup> ISO-NE has developed and implemented significant measures to make the system resilient against these identified HI/LF events, and is continuously building on already extensive system of process controls, advanced detection and response systems, and redundancy in systems and control centers in order to be able to detect, withstand, and recover from any cyber or physical attacks, as well as to comply with mandatory standards.

With respect to fuel-security, the focus of this response, ISO-NE conducted the OFSA to quantify the fuel-security risk in the future. The OFSA’s Outage Cases examined the potential operational impacts of a winter-long outage of key energy facilities in the region: (1) a compressor station on a major natural gas pipeline; (2) the loss of Millstone Nuclear Station; (3) the loss of the Canaport LNG import and regasification facility in New Brunswick; and, (4) a disruption of the Distrigas LNG import facility that fuels the Mystic 8 and 9 natural gas-fired combined cycle generating units. Although the OFSA does not specify the probability of these cases, it qualitatively recognizes that losing any one of these key energy facilities for the entire winter period, or even shorter periods, represents HI/LF risks.

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<sup>56</sup> North American Electric Reliability Corp. and the U.S. Dept. of Energy, High-Impact, Low-Frequency Event Risk to the North American Bulk Power System (2009), <https://energy.gov/sites/prod/files/High-Impact%20Low-Frequency%20Event%20Risk%20to%20the%20North%20American%20Bulk%20Power%20System%20-%202010.pdf>.

<sup>57</sup> North American Electric Reliability Corp., Cyber Attack Task Force Final Report (2012), [http://www.nerc.com/%20docs/cip/catf/12-CATF\\_Final\\_Report\\_BOT\\_clean\\_Mar\\_26\\_2012-Board%20Accepted%200521.pdf](http://www.nerc.com/%20docs/cip/catf/12-CATF_Final_Report_BOT_clean_Mar_26_2012-Board%20Accepted%200521.pdf).

<sup>58</sup> Resilience Order at P 12.

The OFSA found that the region is most vulnerable to the winter-long outage of any of these key facilities, resulting in hundreds of hours of Operating Procedure actions, including emergency actions, and between two dozen and more than 100 hours of load shedding. Such HI/LF risks are among the events used in training, such as the NERC GridEx IV exercise, to train ISO-NE System Operators, so that they are able to recognize and respond to the event should it unfold. .

#### Planning for Risk:

As described in Part II.A above, in system planning, ISO-NE assesses the impacts of HI/LF events on the performance of the system and its ability to withstand such events. Currently, ISO-NE transmission planning assessments include HI/LF events contingency testing under planning criteria prescribed by NERC, as well as NPCC. The NERC criteria applied in the studies ensures that the resulting system is robust and can withstand a wide range of possible events. In addition to the NERC TPL standards, which cover general transmission system design and also planning for geomagnetic disturbances, other NERC standards, such as CIP-014, create the obligation to limit substation vulnerabilities due to a physical attack. NPCC standards and criteria enforce another layer of conservatism in both system planning and design. Under NPCC criteria, for example, ISO-NE is required to evaluate the system with an element out of service and either the loss of two circuits on a common structure or loss of an element combined with the failure of a circuit breaker to operate. NPCC also requires the installation of two independent protection systems at stations deemed to have the potential for a significant impact on reliability, and further requires dual high-speed protection systems on certain facilities in New England. Both of these requirements ensure that system events are addressed quickly, limiting their potential for adverse impacts on the overall transmission system.

While studies like the OFSA provide a detailed look at the fuel-security challenges based on the wide range of hypothetical cases examined, ISO-NE's transmission planning assessments also include a view as to the system's ability to withstand certain gas systems contingencies. Under NERC extreme event testing requirements, ISO-NE considers the loss of two generation stations on a natural gas pipeline system. Under NPCC criteria, ISO-NE considers the impact of the loss of the interstate pipeline serving the largest amount of gas-fired generation. In planning,

however, both of these assessments assume the ability of natural gas-fired generator with dual-fuel capability to switch over to alternate fuels, and run with the alternate capability for an extended period of time, an assumption that does not necessarily reflect the real-world initial alternative fuel availability or the inventory to operate for a period of several days. Because these events are identified as an extreme system contingency in the criteria, it is not necessary to plan transmission to cover for issues found during such testing, especially with operational analyses, such as the OFSA, illustrating much larger fuel-security challenges. As discussed above, one of the objectives of the OFSA is to engage in discussions with regional stakeholders on what level of risk the region will tolerate.

Designing the system to withstand certain HI/LF risks, such as those relating to the environment, further contributes to the resilience of the power system. New England Transmission Owners are undertaking efforts to ensure that, for example, substations can better withstand flooding associated with severe weather events, such as hurricanes. These coastal flood events have occurred more frequently in recent years, as late as the nor'easter during the week of February 25, 2018 – raising questions about their low frequency status. The efforts to mitigate the impacts of seawater intrusions on bulk power system facilities have included measures, such as, raising sensitive equipment, installation of flood walls, and complete relocation and rebuild of a substation.

#### Operational Measures:

As part of its overall operational readiness, ISO-NE performs reliability assessments and real-time security studies to ensure that system resources can be re-dispatched to address contingencies and adhere to mandatory requirements for maintaining operating reserves that can be called on to produce electricity should a contingency occur. ISO-NE has also developed operational measures that it implements in preparation for and to support the power system's resilience against HI/LF events. In the context of fuel-security, ISO-NE has developed and implemented measures to increase its overall situational awareness in advance of, during, and after extreme cold weather events, such as the 2017/2018 Cold Winter Stretch, during which fuel-security is most challenged. Examples of these measures include:

- Operating Procedures designed to improve information on generator availability during cold weather conditions. For example, OP-21 requires generators to report their anticipated availability to ISO-NE, including details on their ability to procure fuel and any physical limitations of their generating units, in anticipation and during an Energy Emergency, which includes when ISO-NE projects fuel constraints. The OP-21 fuel surveys ask asset owners to report the amount of fuel in their inventories, their plans for replenishment, their storage capability, their dual-fuel operating characteristics, and their environmental restrictions. ISO-NE conducts monthly fuel surveys, but may conduct surveys more frequently, as was the case during the 2017/2018 Cold Weather Stretch, during which ISO-NE conducted surveys at twice weekly and daily intervals.
- Situational awareness tools, such as the Gas Usage Tool, to assess the fuel availability of natural gas-fired generators on a daily basis, prompting system operators to reach out to pipeline operations staff when deficiencies may be anticipated. The Gas Usage Tool allows ISO-NE to visualize natural gas system flow and estimate the amount of natural gas available for electric generation. This is accomplished by estimating the demand for gas by industrial and local gas distribution companies' customers, as well as gas-fired generators, compared to the capability of the natural gas-fuel infrastructure, including LNG injections into the regional gas-fuel infrastructure pipelines.
- Tariff, Operating Procedures, and business practice changes to facilitate communications and foster information-sharing relationships with regional gas industry in New England – thereby, improving the ability detect conditions on the gas system that could affect the availability of gas-fired generation. ISO-NE revised its Information Policy to allow ISO-NE to share information concerning the scheduled output of gas-fired generators with the operating personnel of the interstate natural gas pipeline companies serving New England. These changes allow ISO-NE to better anticipate and address potential reliability problems in the event that there is insufficient fuel for all gas-fired generators to meet their schedules. As described below, ISO-NE participates in conference calls held with members of the Electric/Gas

Operations Committee (“EGOC”). These conference calls are held quarterly or more frequently if members anticipate severe or abnormal conditions on their systems. ISO-NE’s Operating Procedures incorporate the EGOC’s Communications Protocol, which identifies the mechanisms to be used should ISO-NE need assistance of any regional natural gas company to help mitigate electric power operating emergencies and/or other abnormal conditions that could jeopardize the reliability of the New England power system. ISO-NE is also in frequent contact with personnel from regional pipelines. During gas sector maintenance periods, electric or gas peak load conditions, and/or extended cold weather periods, system operators contact their pipeline counterparts daily or multiple times a day. In addition to these communications, ISO-NE also receives Informational Postings from regional pipelines’ Electronic Bulletin Boards (“EBB”) concerning both Critical and Non-Critical Notices, Operational Flow Orders, and Planned Service Outages. As many of the gas-fired generators in New England are directly connected to the regional interstate pipelines, monitoring the EBBs provides ISO-NE with direct situational awareness of the impact of conditions on the interstate pipelines on the New England electric system.

In addition, the Operating Procedures used to quantify the operational risks posed by the various scenarios examined in the OFSA (*i.e.*, OP-4 and OP-7) provide ISO-NE system operators the tools necessary to manage imbalances in supply and demand, as well as emergency actions should more serious conditions unfold. These procedures are designed to maintain the integrity of the bulk power system. ISO-NE employs these procedures to respond to emergencies, such as generation or transmission contingencies due to HI/LF events. When deploying these emergency procedures, ISO-NE can call for the action that will best address the situation presented; no specific order of implementation is required. The order or speed at which the emergency actions would need to be implemented would change depending on the situation presented. In an extreme emergency, for example, ISO-NE can skip the order of the steps as they are presented in the procedures and operate load shedding immediately in order to protect the system’s integrity.

- d. Should each RTO/ISO be required to identify resilience needs by assessing its portfolio of resources against contingencies that could result in the loss or unavailability of key infrastructure and systems? For example, should RTOs/ISOs identify as a resilience threat the potential for multiple outages that are correlated with each other, such as if a group of generators share a common mode of failure (e.g., a correlated generator outage event, such as a wide-scale disruption to fuel supply that could result in outages of a greater number of generating facilities)? The RTOs/ISOs should also discuss resilience threats other than through a correlated outage approach. Do RTOs/ISOs currently consider these types of possibilities, and if so, how is this information used?*

Because each region is unique, it should be left to the region's respective RTO/ISO to determine what, if any, assessments are needed in light of the type of resilience threats faced there. As noted, the most significant challenges to the resilience of the New England power system relate to fuel security. As evidenced by the OFSA, ISO-NE already engages in the assessments contemplated.

- e. Identify any studies that have been conducted, are currently in progress, or are planned to be performed in the future to identify the ability of the bulk power system to withstand a high-impact, low-frequency event (e.g., physical and cyber-attacks, accidents, extended fuel supply disruptions, or extreme weather events). Please describe whether any such studies are conducted as part of a periodic review process or conducted on an as-needed basis.*
- f. In these studies, what specific events and contingencies are selected, modeled, and assessed? How are these events and contingencies selected?*
- g. What criteria (e.g., load loss (MW)), duration of load loss, vulnerability of generator outages, duration of generator outages, etc.) are used in these studies to determine if the bulk power system will reasonably be able to withstand a high-impact, low-frequency event? Are the studies based on probabilistic analyses or deterministic analyses?*

*In this response, ISO-NE addresses Questions "e", "f", and "g".*

ISO-NE studies assessing the bulk power system's ability to withstand a HI/LF event include:

- **Planning Studies:** As described in response to Question “c” above, transmission planning assessments include contingency testing under planning criteria prescribed by NERC, as well as NPCC, which ensure that the resulting system is robust and can withstand a wide range of possible events. While these planning studies can be performed on an as-needed basis, ISO-NE currently performs them as prescribed by the applicable NERC and NPCC standard and criteria. Examples of these assessments include: the annual assessments required by NERC TPL-001, the geomagnetic disturbance assessments required by NERC TPL-007, physical security assessments required by NERC CIP-014, and the NPCC Comprehensive Area Reviews. As noted, the events tested are typically dictated by the standard being addressed by a particular study. For example, in evaluating extreme event contingencies for NERC testing, ISO-NE assesses the loss of two stations supplied by the same gas pipeline. NPCC Comprehensive Area Reviews require the assessment of the loss of a gas pipeline. The thresholds used in long-term transmission planning assessments also vary by the type of assessment being performed. In the evaluation of three-phase faults with failure of a circuit breaker to operate, ISO-NE uses a loss of source threshold of between 1,400 MW and 2,000 MW. Use of this threshold has resulted in a number of circuit breakers being installed with independent pole tripping and/or the installation of redundant circuit breakers. In establishing thresholds for cascading due to extreme events, such as the loss of a substation, ISO-NE uses a source loss threshold of 2,200 MW.
  
- **Operational Analyses:**
  - Operable Capacity Assessments – ISO-NE conducts analyses for future planning days of known and unknown generator outages for assessing the capacity available to maintain a positive margin for the system.
  
  - RAA – ISO-NE conducts the RAA to ensure sufficient generators are available to meet capacity and reserve requirements for the current and next operating day. In these assessments, ISO-NE reviews the difference

between ISO-NE forecast of demand the total demand that cleared in the DAM and commit additional generators if the commitments are not sufficient to ensure adequacy of capacity to provide energy and reserves.

- Contingency Analysis – ISO-NE conducts contingency analyses to stay ahead of a potential event before it unfolds. ISO-NE’s security-constrained dispatch allows system operators to reliably and economically operate the bulk power system. To facilitate this, ISO-NE performs contingency analysis to verify the power system is protected thermally and for voltage for the unexpected failure or outage of an element, such as a generator, transmission line, circuit breaker, switch, or other electrical element. The software used for contingency analysis runs automatically every few minutes or whenever a system operator manually initiates the process. This analysis simulates taking each system component out of service, one at a time, to determine how the power system is affected. Thousands of contingencies are studied each time the contingency analysis runs, resulting in a list of all post-contingency. The analysis also provides a list of all post-contingency, transmission-element overloads that could occur following each contingency studied. The results of these analyses feed into the unit-dispatch software or UDS, which, in turn, develops a security-constrained economic dispatch solution, making slight adjustments to generator output to influence the flow of power through the system. This change in the flow of power can prevent a modeled contingency event, should it occur, from exceeding a limit or precipitating uncontrolled load shedding or a cascading outage.
- Other Fuel-Security Related Studies:
  - OFSA - The OFSA, which, as described earlier, examined the potential impacts on the system’s ability to withstand a winter-long outage of four key energy facilities in the New England region.

- Eastern Interconnection Planning Collaborative (“EIPC”) Gas-Electric Systems Study – ISO-NE, along with NYISO, PJM, TVA, MISO and IESO, participated in the EIPC’s Gas-Electric System Interface Study, which analyze the electric power system’s interface with the natural gas sector. The main objectives of the study were: (1) develop a baseline assessment of the existing natural gas and electric power system infrastructures; (2) evaluate the capability of the natural gas system to meet the seasonal needs of the electric power system’s fuel requirements; (3) identify contingencies on the natural gas system that could adversely affect electric power system reliability and vice versa; and, (4) review operational and planning issues, including fuel-assurances affecting the economics of dual-fuel power plants compared with incremental firm gas pipeline expansion.

***h. Do any studies that you have conducted indicate whether the bulk power system is able to reasonably withstand a high-impact, low frequency event? If so, please describe any actions you have taken or are planning as mitigation, and whether additional actions are needed.***

In many cases, long-term transmission planning assessments show that the system can withstand a number of potential extreme events. However, some testing shows that there are certain vulnerabilities to extreme events which could have widespread consequences. To address these events, significant system redesign would be necessary, most likely requiring additional transmission circuits, potentially dictating, in turn, the creation of new and separate rights-of-way and the addition of new substations, all at significant costs. That said, there are a number of actions being taken to limit the likelihood of certain events. In planning, the decision to proceed with one set of transmission solutions versus another alternative is informed by extreme event testing, such as comparably better or worse performance for as loss of a substation and loss of a right-of-way, when evaluating alternatives. In addition, the New England Transmission Owners are in the process of implementing measures at certain substations to ensure that they can better withstand potential issues associated with flooding that has become more frequent in recent

years. They are also increasing physical security protections at certain stations as a result of NERC CIP-014.

The operational readiness assessments are performed to ensure that system resources can be re-dispatched to address contingencies and adhere to mandatory requirements for maintaining operating reserves that can be called on to produce electricity should a contingency occur. The contingency analyses verify the power system remains protected thermally and for voltage should an unexpected failure or outage of an element occur, and the outputs of that analysis are factored in security-constrained economic dispatch of the system.

The OFSA is an operational deterministic analysis that looks at a wide range of possible generation and fuel-mix scenarios to assess the operational impacts on the reliable operations of the New England power system during a future winter period. One of the key objectives of the OFSA is to engage in discussions with regional stakeholders on what level of fuel-security risk the region will tolerate and the potential solutions to address that risk. As the System Operator responsible for the system's reliability, ISO-NE also needs to independently assess the level of risk to reliable operation. The Commission also has an important role in providing direction regarding the acceptable level of risk of electric service interruptions that ISO-NE should account for. As noted, even where a risk is deemed unacceptable, the solution needed to address or most effectively address a given issue may lay outside of the ability of ISO-NE to direct or otherwise accomplish.

- i. How do you determine whether the threats from severe disturbances, such as those from low probability, high impact events require mitigation? Please describe any approaches or criteria you currently use or otherwise believe are useful in determining whether certain threats require mitigation.*

Whether further mitigation is needed depends on the magnitude of the impact on ISO-NE providing an adequate level of resilience. With respect to fuel-security, ISO-NE developed the OFSA to better understand what levels of risk to reliability it would encounter as the grid operator under a wide range of possible combinations of generating resource and fuel mixes. In quantifying the operational risks in each scenario, ISO-NE sought to provide regional

policymakers and stakeholders the information they need to help ISO-NE determine what level of fuel-security risk the region will tolerate and develop potential solutions to address the risk. Some mitigation solutions may be outside scope of ISO-NE's jurisdiction and may need to be addressed by other appropriate entities. However, regardless of the probability, system operators need to be able to respond to prevent uncontrolled load shedding and cascading outages. ISO-NE utilized the loss of the compressor scenario for the NERC GridEx IV exercise to train the operators, as, on any given day, such a HI/LF event would likely require controlled load shedding and then the restoration of that load after the start-up and synchronization of generators with dual-fuel capability and other non-gas resources.

***j. How do you evaluate whether further steps are needed to ensure that the system is capable of withstanding or reducing the magnitude of these high-impact, low frequency events?***

See response to Question "i" above.

***k. What attributes of the bulk power system contribute to resilience? How do you evaluate whether specific components of the bulk power system contribute to system resilience? What component-level characteristic, such as useful life or emergency ratings, support resilience at the system level?***

In the Resilience Order, the Commission generally bases its understanding of resilience on the National Infrastructure Advisory Council's ("NIAC") resilience framework.<sup>59</sup> NIAC's resilience framework includes four outcome-focused abilities: robustness, resourcefulness, rapid recovery, and adaptability.<sup>60</sup> These attributes would contribute to the bulk power system's resilience.

As described in this response, the performance and needs of the New England bulk power system are assessed and designed to NERC, NPCC and ISO-NE planning standards and procedures, leading to a robust and, therefore, resilient system. The New England bulk power system has inherent attributes of resilience, because it is planned for and designed to meet the

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<sup>59</sup> See Resilience Order at P 23.

<sup>60</sup> See *id.*

deterministic planning criteria established by NERC, and built to withstand the environmental conditions. In order to meet these criteria, a highly networked system, consisting of many parallel paths, has been built in New England. For instance, upon the loss of a transmission facility, the remaining parallel facilities continue to carry power to other parts of the network. Further, in New England, transmission facilities are planned using two of the four available equipment ratings (*i.e.*, normal ratings, which are continuous ratings, and long-term emergency ratings, which can be used for 12 hours in the summer). Generally, the remaining two higher ratings are reserved for system operations, with a short-time emergency rating that can be used for fifteen minutes and a drastic action limit that can be used for five minutes in dire emergencies. Planning the system in this manner allows for some margin between the planned system and the system that the operators face in real time operations.

In addition, NPCC criteria require the installation of fully redundant protection systems at critical substations across the network, where loss of one protection system does not compromise the system's ability to quickly remove a faulted facility from service. New England is also required to install dual high-speed protection systems on critical elements, again, with the objective of ensuring that faulted elements are removed from the network quickly, limiting the larger impact of the disturbance.

The most significant challenge to the resilience of the New England power system now relate not to transmission, but to generation not having, or being able to obtain, the fuel they require to meet system demand and required reserves, particularly during extended periods of winter (or other system-stressed) conditions, such as the 13-day period observed this winter. The OFSA identifies for ISO-NE and stakeholders the growing fuel-security risk due to the heavy reliance on natural gas. Similar concerns exist when there is a heavy dependence on other resources. For instance, a system that is heavily dependent on wind power would struggle during times when the wind is not blowing, which often coincides with summer peak load conditions. The region experienced similar issues in the 1970's and 1980's when oil embargoes severely limited the energy that could be produced by a generation fleet whose fuel of choice was oil.

For the power system to be resilient, as the above examples indicate, resources must have the fuel to produce power when needed and must be able to operate consistent with their parameters, and in amounts that allow for reliable operations under winter peak (or other system stressed) conditions. Resources that can be available for an extended period typical of winter (or other system stressed) conditions, with such capability to be able to absorb and recover from fuel supply disruptions (and to be replenished in order to prepare for possible back-to-back events – would contribute to the resilience of the power system. The OFSA simulations of scenarios with higher levels of LNG, dual-fuel generating capability, imports, and renewable resources indicate that a resource mix with these resources help to reduce the fuel-security risk. ISO-NE will be working with stakeholders to develop a long-term solution that improves the logistics associated with these fuels.

- l. If applicable, how do you determine the quantity and type of bulk power system physical asset attributes needed to support resilience? Please include, if applicable, what engineering and design requirements, and equipment standards you currently have in place to support resilience? Are those engineering and design requirements designed to address high-impact, low-frequency events? Do these requirements change by location or other factors?***

See response to Question “k” above.

- m. To what extent do you consider whether specific challenges to resilience, such as extreme weather, drought, and physical or cyber threats, affect various generation technologies differently? If applicable, please explain how the different generation technologies used in your system perform in the face of these challenges.***

ISO-NE seeks to understand the locations, attributes, and limitations of each of the resources comprising the New England generating fleet, in order to improve overall situational awareness, and to be able to anticipate and address potential issues before they unfold. For example:

- ISO-NE has established procedures to improve information on generator availability during cold weather conditions.<sup>61</sup> These procedures require generators to report their anticipated availability to ISO-NE, including details on their ability to procure fuel and any physical limitations of their generating facilities. ISO-NE also surveys oil-fired generation for information on oil inventory, plans for refueling, replenishment strategies, procurement and transportation issues, and environmental or emissions issues.
- ISO-NE, in coordination with the owners of nuclear facilities, transmission owners and the local control centers, developed Master/Local Control Center Procedure No. 1, Nuclear Plant Transmission Operations,<sup>62</sup> along with associated attachments, which provides nuclear unit-specific details, along with conditions for entering their abnormal operating procedures for high winds, hurricanes and blizzards.
- ISO-NE has been studying, gathering operational data and observations on variable energy resources. ISO-NE has developed wind forecasts that it incorporates into ISO-NE processes, scheduling and dispatch services. To improve System Operators' situational awareness, ISO-NE has created display tools and is maintaining historical wind data for future use by the forecast services and in other analyses. ISO-NE has developed operational solar forecasts to account for the impacts of solar PV facilities on system load in the short-term to support the reliable operation of the system. Solar PV facilities power production increases variability and uncertainty to the system that can eventually affect system operations, such as a need for additional reserves, regulation or ramping. ISO-NE continues to improve load forecasting to address these challenges

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<sup>61</sup> See, e.g., OP-21.

<sup>62</sup> [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/mast\\_satllte/mlcc1.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/mast_satllte/mlcc1.pdf).

- n. To what extent are the challenges to the resilience of the bulk power system associated with the transmission system or distribution systems, rather than electric generation, and what could be done to further protect the transmission system from these challenges?***

As discussed above, there are two key aspects to power system resilience – the system’s security and adequacy – and both play an important role and need to be addressed.

- o. Over what time horizon should the resilience assessments discussed above be conducted, and how frequently should RTOs/ISOs conduct such an analysis? How could these studies inform planning or operations?***

The horizon for transmission planning studies in New England is ten years, and the operational readiness assessments are performed near or in real-time to support real-time system operations.

In general, the timing and frequency for assessments should be driven by the nature of the risks to the reliability of each region’s system. Assessments should be performed so that necessary investments can be made in time to mitigate the risks. With respect to fuel-security, ISO-NE selected 2024-2025 as the target winter to allow sufficient time in the intervening years to carefully consider the fuel-security risk and develop and implement the appropriate longer-term solutions, and let the investments be made. However, if circumstances dictate that the region’s fuel-security challenges become more pressing before a longer-term solution can be developed and implemented, ISO-NE will take any interim measures necessary to address near-term reliability risks.

- p. How do you coordinate with other RTOs/ISOs, Planning Coordinators, and other relevant stakeholders to identify potential resilience threats and mitigation needs?***

As indicated in previous responses, ISO-NE coordinates with NERC, NPCC, other RTOs/ISOs, regional gas pipelines, LDCs and LNG facilities to identify potential resilience threats and mitigation needs. Most notably:

- NERC – ISO-NE participates and follows the work of the NERC Standing Committees, particularly the Planning, Operating, and Critical Infrastructure

Protection Committee. As noted above, ISO-NE participates, reviews and evaluates HI/LF NERC studies, responds to alerts, and actively participates in the standard development process to ensure that the reliability standards address any gaps. ISO-NE also participates as a member of the NERC Membership Representative Committee, which, among other things, provides input to the NERC Board.

- NPCC – ISO-NE is a member of NPCC and fully participates in NPCC activities. ISO-NE participates in the conference calls with NPCC Reliability Coordinators. In preparation for cold weather conditions, ISO-NE reviews with NPCC Reliability Coordinators expected weather and peak loads for the current and next day; expected MW surplus above the operating reserve requirements; expected interchange schedules; and conditions of natural gas supply and fuel oil inventory.
- EGOE – ISO-NE is co-chair of the EGOE along with the NGA. The EGOE includes over 50 members with representatives from ISO-NE, NYISO, PJM, NERC, NPCC, and regional interstate gas pipelines, LDCs and LNG facilities. ISO-NE participates in EGOE routinely-held conference calls during which members discuss upcoming issues on their systems, including planning maintenance outages. More frequent calls are held if members anticipate severe or abnormal conditions on their systems. ISO-NE follows the EGOE Communications Protocol, which, among other things, specifies the regular flow of information, real-time communications, communications between ISO-NE and NGA and regional gas companies, and emergency industry contact information of coordination during non-business hours.
- EIPC – Through the EIPC, ISO-NE coordinates with Planning Authorities in the Eastern Interconnection. The EIPC, formed in 2009, addresses the Planning Authorities’ portion of North America planning issues, combines existing transmission expansion plans, and analyzes the interconnection-wide system.

- Northeast ISO/RTO Planning Coordination Protocol (“Protocol”) – To implement the Protocol, which requires interregional planning coordination among neighboring areas, ISO-NE participates in the Joint ISO/RTO Planning Committee (“JIPC”) and the Interregional Planning Stakeholder Advisory Committee (“IPSAC”). The JIPC and IPSAC facilitate interregional coordination and communication.
- Regional Stakeholders – ISO-NE coordinates with stakeholders, for example, through: (1) the New England Power Pool (“NEPOOL”), which is the voluntary association of the participants in New England’s wholesale markets; (2) ISO-NE stakeholder meetings, such as the Planning Advisory Committee for regional transmission planning; and, (3) state regulators, including those who form the New England Conference of Public Utilities Commissioners (“NECPUC”) and New England States Committee on Electricity (“NESCOE”).

***q. Are there obstacles to obtaining the information necessary to assess threats to resilience? Is there a role for the Commission in addressing those obstacles?***

ISO-NE has been able to get the information needed to assess the resilience of the bulk power system.

***r. Have you performed after-the-fact analyses of any high-impact, low-frequency events experienced in the past on your system? If so, please describe any recommendations in your analyses and whether they have or have not been implemented.***

ISO-NE uses the data obtained from experience with system-stressing events as an input to test against HI/LF events. As an example, the 2014-2015 winter served as the baseline for testing system stresses in the modeled, hypothetical cases examined in the OFSA. It was a cold winter, but also provided a cold spell that was similar in duration to the cold weather stretch the region just experienced.

### C. Responses on How ISO-NE Mitigates Threats to Resilience

- a. *Describe any existing operational policies or procedures you have in place to address specific identified threats to bulk power system resilience within your region. Identify each resilience threat (e.g., the potential for correlated generator outage events) and any operational policies and procedures to address the threat. Describe how these policies or procedures were developed in order to ensure their effectiveness in mitigating the identified risks and also describe any historical circumstances where you implemented these policies or procedures.*

To ensure consistent, reliable operation of the bulk power system on a day-to-day basis, ISO-NE has developed and follows detailed procedures that incorporate and meet NERC and NPCC standards. These provides include: (1) Operating Procedures, which outline certain steps ISO-NE takes to manage New England’s bulk power system; (2) System Operating Procedures, which detail the operation of the bulk power system (e.g., outage scheduling operating procedures); and, (3) Master and Local Control Center Procedures, which guide the relationship and coordination between ISO-NE and the separate local control centers in the region.

As discussed above, after the 2004 Cold Snap, ISO-NE developed new Operating Procedures, and enhanced operational tools and system to mitigate fuel-security risk. For example, ISO-NE worked with regional stakeholders in its development of OP-21, which is specifically designed to improve information on generator availability during cold weather conditions. Procedures, such as ISO-NE’s Master/Local Control Center Procedure No. 8, Coordination of Generator Voltage Regulator and Power System Stabilizer Outage<sup>63</sup> further improve ISO-NE’s overall situational awareness. This procedure sets out requirements regarding the coordination of outages of devices that, if removed from service, can impact the ability of the power system to respond dynamically to normal power changes, unplanned events, and abnormal conditions (e.g., automatic voltage regulators, power system stabilizers, and reactive control systems).

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<sup>63</sup> [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/mast\\_satllte/mlcc8.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/mast_satllte/mlcc8.pdf).

ISO-NE also employs Operating Procedures to serve demand while maintaining the required levels of reserves. Specifically, ISO-NE uses OP-4 to maintain supply and demand in balance, avoid violating the 10-minute operating reserve requirement, and averting the need to implement load shedding. This procedure sets out a number of actions that ISO-NE system operators step through to address problems as they present themselves in real time. The initial actions (Actions 1 through 5) under OP-4 are internal to the industry. In these steps, ISO-NE works with Transmission Owners, Market Participants and Neighboring Control Areas to address the problems. If these actions are not sufficient, OP-4 specifies higher-level actions (Actions 6 through 11), which may be more obvious to the public, such as voltage reductions, and urgent appeals for public conservation. ISO-NE also uses OP-7, its emergency procedure for implementing load shedding after ISO-NE starts depleting 10-minute operating reserves. OP-7's objectives are to protect the reliable operation of the Eastern Interconnection, restore balance between customers' load and available generation in the shortest practicable time, minimize risk of damage to equipment, and minimize interruption of customer service. These emergency procedures are designed to maintain the integrity of the bulk power system. They are used to respond to emergencies, such as transmission and generation contingencies, due to HI/LF events identified in the earlier responses. The order or speed at which these emergency actions would need to be implemented, however, would change depending on the circumstances presented. For example, ISO-NE can bypass other steps and move immediately to controlled load shedding if necessary to preserve the reliability of the bulk power system.

ISO-NE also has a System Restoration Plan in place to programmatically restore the system or portions thereof, depending on the expanse of the blackout.

***b. How do existing market-based mechanisms (e.g., capacity markets, scarcity pricing, or ancillary services) currently address these risks and support resilience?***

The wholesale electricity markets are designed to procure sufficient power resources to maintain reliability. ISO-NE has revised the rules governing the energy, capacity, and ancillary markets to address fuel-security concerns. For example:

- Energy Markets – In 2013, ISO-NE shifted the DAM to better align the electricity and natural gas markets to give generators more time to procure the gas they need to run. As a result of these changes, ISO-NE now closes the DAM offer and bid period at 10 am (as compared to 12 pm under the former rules), giving generators more time to nominate the gas they need to run the following operating day. In 2014, ISO-NE also implemented energy market offer-flexibility enhancements to allow Market Participants to update their offers to supply electricity in real-time to reflect changing fuel costs, improving market pricing and incentives to perform.
- Capacity Market – Through the Pay For Performance suite of changes filed and approved in 2014, ISO-NE tightened the Shortage Event trigger in FCM to ensure the Shortage Event triggered earlier in a period of reserve deficiency, and increased payments to resources providing reserves during scarcity conditions. These changes give resources incentives to undertake all cost-effective investments that enable them to perform when they are needed most, with the potential that the significant rewards and penalties will cause generators to respond with improved fuel arrangements. The Pay For Performance rules will take effect in the Capacity Commitment Period beginning on June 1, 2018. While it is expected that the Pay For Performance will incent power plants to secure more reliable wintertime fuel arrangements, as fuel constraints worsen, the markets may need to present stronger rewards or forfeiture risks to drive change.
- Ancillary Services – In 2013, ISO-NE implemented market rule changes to increase the amount of Ten-Minute Reserve capability that is procured in advance through the Forward Reserve Market in response to the degraded historical performance of reserve resources.<sup>64</sup> Permitting an additional amount of reserve to be procured in the FRM helps support the availability and deliverability of reserves to meet the increased real-time reserve requirements. Later in 2013,

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<sup>64</sup> See *ISO New England Inc., et al.*, Letter Order, Docket No. R13-465-000 (Feb. 8, 2013).

ISO-NE implemented market rules to improve the performance incentives associated with the FRM.<sup>65</sup> The revisions to the Forward Reserve Failure-to-Reserve Penalty sought to better incent appropriate performance by reserve resources. In addition, in 2013, ISO-NE modified generator resource auditing requirements and procedures to provide the ISO with a more accurate assessment of the 10 and 30 minute reserve capability of reserve resources,<sup>66</sup> as well as auditing the claimed capability of generators.

***c. Are there other generation or transmission services that support resilience? If yes, please describe the service, how it supports resilience, and how it is procured.***

New England's interconnection and transmission services are designed to work in conjunction with the New England wholesale electric markets. Pursuant to New England's Interconnection Procedures, Capacity Network Resource Interconnection Service and Capacity Network Import Interconnection Service allow Generating Facilities and certain Elective Transmission Upgrades ("ETU"), respectively, to provide the region capacity and energy through the wholesale electricity markets.<sup>67</sup> The Network Resource Interconnection Service and Network Import Interconnection Service allow these resources to participate in all wholesale electricity markets except the FCM.<sup>68</sup> Regional transmission service over the higher-voltage transmission facilities works in conjunction with the markets; the resources are scheduled based on economics, with the least-cost energy transactions scheduled first.

ISO-NE has also made significant Tariff changes to improve the process for interconnecting new resources, including ETUs, wind resources, and other inverter-based technologies.<sup>69</sup> While the ETU Interconnection Procedures *per se* do not directly address the

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<sup>65</sup> See *ISO New England Inc., et al.*, Letter Order, Docket No. ER13-1733-000 (Aug. 15, 2013).

<sup>66</sup> See *ISO New England Inc., et al.* 142 FERC ¶ 61,024 (2013).

<sup>67</sup> See OATT at Schedules 22, 23 and 25.

<sup>68</sup> See *id.*

<sup>69</sup> See *ISO New England Inc. and Participating Transmission Owners Admin. Comm.*, 155 FERC ¶ 61,031 (2016); *ISO New England Inc.*, 151 FERC ¶ 61,024 (2015); *ISO New England Inc., et al.*, 126 FERC ¶ 61,080 at P 14 (2009).

fuel-security risk discussed in this response, they provide the mechanism by which developers may pursue new transmission facilities to better integrate internal generation, as well as to interconnect to neighboring Control Areas to import capacity and energy into the New England region. The recently-approved revisions to the Interconnection Procedures to incorporate a methodology for considering Interconnection Requests on a cluster basis also facilitate the interconnection of resources, which are mostly wind, located in remote parts of the system.<sup>70</sup> Significant investment in transmission infrastructure is needed to move the power to consumers from the weak-grid areas of the system where half of the proposed wind resources would be sited. The revisions help by expediting the study process, and providing the mechanism for allocating the transmission upgrade costs among the cluster participants.

In addition to these process enhancements, as a condition of interconnection, New England's Interconnection Agreements and Operating Procedures require Generating Facilities, including wind and inverter-based technologies, and ETUs to meet certain design and performance requirements, such as reactive power, voltage and frequency response performance capabilities, that help maintain the power system's performance. Models must accurately represent the equipment performance so that ISO-NE can fully understand the expected behaviors.

Pursuant to Schedule 2 of the OATT, ISO-NE also compensates resources (generating and non-generating dynamic reactive resources) for maintaining reactive power or VAR capability necessary for ISO-NE system operators to maintain transmission voltages within an acceptable range. Under Schedule 16, ISO-NE compensates specific generating plants at key locations for their blackstart capability, which is needed to restart the transmission system following a blackout.

***d. How do existing operating procedures, reliability standards (e.g., N-1 NERC TPL contingencies), and RTO/ISO planning processes (e.g., resource adequacy programs or regional transmission planning) currently consider and address resilience?***

All ISO-NE planning assessments must comply with NERC and NPCC reliability requirements for meeting resource adequacy and transmission planning criteria and standards.

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<sup>70</sup> See *ISO New England Inc.*, 161 FERC ¶ 61,123 (2017).

These standards and criteria, which include testing against certain contingencies or events, are designed to ensure the operation of the power system can withstand pre-defined disturbance without resulting in cascading failure of the system. Additionally, NERC TPL-001-4 and NPCC Directory 1 require consideration of extreme events, though mitigation is not required.

***e. Are there any market-based constructs, operating procedures, NERC reliability standards, or planning processes that should be modified to better address resilience? If so, please describe the potential modifications.***

ISO-NE will work with regional stakeholders to develop potential long-term solutions to address the region's fuel-security risk, including modifications to better recognize fuel constraints in the markets, strengthen the financial incentives for plants to secure more reliable wintertime fuel arrangements, and, if necessary retain resources essential to ensure grid reliability. However, it will be up to Market Participants and state officials to take actions to secure forward fuel arrangements and bolster supply- or demand-side infrastructure to resolve the fundamental causes of fuel-delivery constraints. Appropriate investments could include enhancements to natural gas infrastructure or the supply chains for LNG and oil; relaxation of rules to facilitate permitting and operation of dual-fuel resources; investments in even more renewables and the transmission needed to deliver it; or further measures to significantly reduce demand on the power system or the gas system.

Respectfully submitted,

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Dated: March 9, 2018  
Attachment

**ATTACHMENT A**

# Operational Fuel-Security Analysis

*For Discussion*



JANUARY 17, 2018  
ISO-NE PUBLIC



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# Highlights: Operational Fuel-Security Analysis

- **Fuel-security risk** – the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter – is the **foremost challenge to a reliable power grid in New England**.
- ISO New England studied **23 possible future resource combinations** during winter 2024/2025 to determine whether enough fuel would be available to meet demand and to understand the operational risks.
- The ISO chose winter 2024/2025 and 23 scenarios to depict a **wide range of possible future power system conditions** in the mid-2020s. Actual power grid conditions could change earlier or later than the 2024/2025 target winter.
- These scenarios, while not a precise prediction of the future system, seek to illustrate the **range of potential risks** that could confront a power system if fuel and energy were constrained during winter.
- The goal is to improve the ISO's and the region's **understanding of these risks** and inform the ISO's subsequent discussions with stakeholders.
- The study assumed that no additional natural gas pipeline capacity to serve generators would be added within the timeframe of this study and instead focused on **five other variables** that are likely to be key factors in power system reliability. Notable findings regarding each variable:



## Resource Retirements

The retirements of coal-fired, oil-fired, and nuclear generators – resources with fuel stored on site – will have a significant impact on reliability and magnify the importance of other variables, particularly liquefied natural gas (LNG) supplies.



## LNG Availability

Improving generators' advance arrangements for timely winter deliveries of LNG could significantly reduce fuel-security risk, while reduced volumes of this global commodity would raise risk.



## Oil Tank Inventories

The availability of oil stored in tanks on site is a key reliability factor and depends on the extent to which natural-gas-fired generators are able to add dual-fuel capability to burn oil, how often they can run on oil, and whether they have oil when needed.



## Imported Electricity

Expanding access to electricity from neighboring power systems would help mitigate fuel-security risk but would require investment in transmission infrastructure.



## Renewable Resources

Accelerating the growth of renewable resources would enhance fuel security but would not eliminate reliance on LNG. It also would likely lead to more non-gas-fired resource retirements and require transmission investment.

→ Energy shortfalls due to inadequate fuel would occur with almost every fuel-mix scenario in winter 2024/2025, requiring frequent use of **emergency actions** to keep power flowing and protect the grid. Emergency actions that would be visible to the public range from requests for energy conservation to load shedding (rolling blackouts affecting blocks of customers).

→ The study's findings suggest **six major conclusions**:

- 1 **Outages:** The region is vulnerable to the season-long outage of any of several major energy facilities.
- 2 **Stored fuels:** Power system reliability is heavily dependent on LNG and electricity imports; more dual-fuel capability is also a key reliability factor, but permitting for construction and emissions is difficult.
- 3 **Logistics:** The timely availability of fuel is critical, highlighting the importance of fuel-delivery logistics.
- 4 **Risk trends:** All but four scenarios result in fuel shortages requiring load shedding, indicating the trends affecting New England's power system may intensify the region's fuel-security risk.
- 5 **Renewables:** More renewable resources can help lessen the region's fuel-security risk but are likely to drive coal- and oil-fired generation retirements, requiring high LNG imports to counteract the loss of stored fuels.
- 6 **Positive outcomes:** Higher levels of LNG, imports, and renewables can minimize system stress and maintain reliability; to attain these higher levels, delivery assurances for LNG and electricity imports, as well as transmission expansion, will be needed.

→ The ISO will discuss the study with regional stakeholders and determine whether further **operational or market design measures** are needed to address the region's fuel-security risk.

# Executive Summary



The health and safety of New England's 14 million residents and the vibrancy of its economy depend on a reliable power supply, and that requires fuel security – that is, a reliable supply of the various fuels used to generate the region's electricity. New England's generation fleet relies primarily on fuels imported from elsewhere in the United States or from overseas to produce power, giving fuel procurement, transportation, and storage a pivotal role in power system operations. This is particularly true during winter when fuel for nearly half the region's generating capacity may become inaccessible due to priority demand for natural gas from the heating sector.

As the operator of the region's six-state power system, ISO New England is required to plan and operate the grid to ensure a reliable supply of electricity. To help fulfill this responsibility, the ISO conducted a fuel-security analysis that evaluated the level of operational risk posed to the power system by a wide range of potential fuel-mix scenarios. The study quantified the risk by calculating whether enough fuel would be available for the system to satisfy consumer electricity demand and to maintain power system reliability throughout an entire winter.

***Fuel-security risk—the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter—is the foremost challenge to a reliable power grid in New England.***

## Background

On multiple occasions in recent winters, the ISO has had to manage the system with uncertainty about whether power plants could arrange for the fuel – primarily natural gas – needed to run.<sup>1</sup> Because the ISO has no jurisdiction over other industries' various fuel-delivery systems, it has addressed the effects of insufficient fuel supplies on the power system by employing real-time emergency operating procedures and implementing market design changes to incentivize generators to arrange for adequate fuel supplies. The ISO has also worked on improving communication and coordination with natural gas pipeline operators.

The ISO has been able to maintain power system reliability during severe winter conditions without using all its emergency procedures. However, the evolving generation mix is increasingly susceptible to variable and uncertain factors. Natural gas pipeline constraints, the logistics of importing liquefied natural gas (LNG)

<sup>1</sup> **Winter 2003/2004:** ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* (October 12, 2004), [https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne\\_final\\_report\\_jan2004\\_cold\\_snap.pdf](https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf); **Winter 2012/2013:** ISO New England, "Winter Operations Summary: January–February 2013," discussion paper (February 27, 2013), [https://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/strategic\\_planning\\_discussion/materials/winter\\_operations\\_summary\\_2013\\_feb\\_27\\_draft\\_for\\_discussion.pdf](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_27_draft_for_discussion.pdf); and **Winter 2013/2014:** ISO New England, "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), <http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabil.html>.

and fuel oil, the impact of New England’s weather on the availability and timing of fuel deliveries, and the amount and timing of electricity generated by renewable resources all contribute to a high level of uncertainty for ISO system operations.

In fall 2016, ISO New England initiated a study to better understand any potential future impacts of fuel-security risk. The study estimated the operational impacts of possible fuel-mix scenarios so that the ISO and the region can assess the level of risk and plan appropriate mitigation, if needed. Economic effects were not measured.

## The Study

While actual power grid conditions could change earlier or later than the target winter, the ISO modeled a wide range of resource combinations that might be possible by **winter 2024/2025**, considering **five key fuel variables**:



**The retirements of coal- and oil-fired generators**



**The availability of LNG**



**Dual-fuel generators' oil tank inventories** (i.e., how often on-site fuel tanks can be filled at dual-fuel generators that can switch between natural gas and oil)



**Electricity imports**



**The addition of renewable resources**

This study did not assess the impacts of adding natural gas pipeline capacity to serve generators within the timeframe of this study. The study incorporated the demand-reducing effects of projected energy-efficiency measures and distributed solar power.

The study includes **23 scenarios**:

- ▶ **1 reference case** incorporates likely levels of each variable if the power system continues to evolve on its current path, serving as a baseline for comparison with other scenarios.
- ▶ **8 single-variable cases** increase or decrease the level of just one key variable to assess its relative impact in each case.
- ▶ **2 boundary cases** illustrate what would happen if either all the favorable or all the unfavorable variables were realized simultaneously.
- ▶ **4 combination cases** combine the five key variables to represent future resource portfolios that could develop and their effects on fuel security.
- ▶ **8 outage cases** illustrate the effects of a winter-long outage at major energy facilities in the region.

The operational impact was measured in hours of emergency operating procedures that would be required to maintain system reliability when not enough fuel was available to generate all the electricity needed to meet forecasted electricity demand.

## Key Takeaways

In almost all future resource combinations, the power system was unable to meet electricity demand and maintain reliability without some degree of emergency actions. Some key takeaways:

- ▶ **Load shedding (19 cases)** – Among the combination cases, all but the most optimistic case resulted in load shedding, also known as rolling blackouts or controlled outages that disconnect blocks of customers sequentially. Load shedding is implemented as a last resort to protect the grid. All but three of the single-variable cases resulted in some degree of load shedding.
- ▶ **Public requests for energy conservation (22 cases)** – All but one of the cases led to the use of emergency actions that include public requests for energy conservation.
- ▶ **No emergency actions (1 case)** – The favorable boundary case represented a best-case resource combination that was fully able to meet demand without special actions. However, it did not reflect the increase in retirements of oil-fired generators that would be expected to accompany increased levels of the other four variables: LNG, oil inventories for dual-fuel generators, imports, and renewables.
- ▶ **Vulnerabilities** – The single-variable cases revealed the region's vulnerability to resource retirements and the availability of LNG. These cases also show that while increasing the amount of renewables would enhance fuel security, it would not eliminate reliance on imported LNG.

**The study results are not precise predictions.** Rather, they help compare different possible future fuel scenarios so that the ISO and the region can discuss a level of tolerable risk and plan appropriate mitigation.

- ▶ **Outages** – All the outage cases resulted in many hours of load shedding, particularly the season-long loss of a nuclear plant or pipeline compressor. Even significant increases in LNG, dual-fuel capability, and renewables would not eliminate the risk. While outages of shorter duration were not studied, it's likely that an outage of any duration at any of these facilities would create significant system stress.

The results are derived from the 23 scenarios analyzed; not every possible future resource combination has been modeled in this study. The study results should not be interpreted as precise measurements. Instead, the number of hours of emergency actions for each fuel scenario should be interpreted as an indicator of system stress.

Taken together, the study results suggest that **New England could be headed for significant levels of emergency actions**, particularly during major fuel or resource outages. Harder to measure are the risks to the region from brief, high-demand cold spells, which present particular logistical challenges for fuel procurement and transportation.

## Next Steps

The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018. A key question to be addressed will be the level of fuel-security risk the ISO, the region, and its policymakers and regulators would be willing to tolerate. A primary consideration for the ISO is its responsibility, as a regional reliability coordinator, to operate the New England power system in a way that maintains the reliability of the entire Eastern Interconnection.<sup>2</sup>

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<sup>2</sup> The Eastern Interconnection is one of two major alternating-current power grids in North America covering from central Canada east to the Atlantic coast (excluding Québec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas). During normal system conditions, all the smaller power systems in this area are electrically interconnected and operate at a synchronized frequency of 60 Hz average. The Eastern Interconnection is tied to the Western Interconnection, the Texas Interconnection, and the Québec Interconnection generally through numerous high-voltage direct-current transmission lines.

# Background:

## The Changing Grid and New England's Fuel-Supply, Infrastructure, and Logistical Challenges



A reliable power system requires a reliable supply of the fuels used to generate electricity. Because New England depends primarily on imported fuels to produce power, fuel security – or the assurance that power plants will have or be able to get the fuel they need, when they need it – is critical for the region's power system reliability.

Fuel security is a growing concern in New England. The regional power system is increasingly dependent on natural gas for power generation; the capacity of the region's natural gas infrastructure is not always adequate to deliver all the gas needed for both heating and power generation during winter; and natural gas is the fuel of choice for a large segment of new power plant proposals. The region's coal, oil, and nuclear power plants, which have fuel stored on site and are essential for reliability when natural gas is in short supply, are retiring. Further, the region has limited dual-fuel generating capability – that is, generators that can use either natural gas or oil – and emissions restrictions on burning oil are tightening.<sup>3</sup>

A dependable fuel supply requires a fuel-delivery system that has the appropriate physical capability to transport all the fuel needed, the contractual arrangements secured in advance to ensure timely deliveries, and power plants that have fuel storage on site. In New England, fuels need to be delivered and storage must be available throughout the winter months.

The region's fuel-security risks have been evident to ISO New England since a 2004 cold snap.<sup>4</sup> The ISO, a private, not-for-profit company independent from all companies doing business in the region's electricity marketplace, operates the six-state power grid around the clock. The ISO is responsible for maintaining the precise balance of supply and demand required to keep the lights on in New England and avoid cascading power system infrastructure outages that can trigger a widespread blackout.

On multiple occasions in recent winters, the ISO's system operators have been confronted with the challenges that arise when power plants can't get fuel. Because the reliability of New England's power system was maintained throughout these events, the region's electricity consumers have been shielded from this growing risk, apart from severe winter price spikes that eventually show up in retail rates.<sup>5</sup>

3. The region's current fleet of dual-fuel capable power plants totals about 8,750 megawatts (MW), but this includes about 2,200 MW from older, oil-fired power plants that rarely run on natural gas and are at risk of retirement.

4. During a January 2004 cold snap, more than 6,000 MW of natural-gas-fired generation was unavailable, much of it due to lack of fuel. ISO New England Internal Market Monitor, *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 'Cold Snap'* (October 12, 2004), [https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne\\_final\\_report\\_jan2004\\_cold\\_snap.pdf](https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf).

5. The total value of the wholesale energy market for the three months of winter 2013/2014 was about \$5.05 billion. By comparison, the value of energy market transactions in 2016 – the year with the lowest wholesale power prices since 2003 – was \$4.1 billion for the entire 12 months. Refer to the ISO's "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014), <http://isonewswire.com/updates/2014/4/4/oil-inventory-was-key-in-maintaining-power-system-reliabilit.html>.

## The Changing Grid

These real-world challenges are likely to intensify as a result of several interconnected trends that are rapidly changing the makeup of New England's power system:

- ▶ Increasing use of natural gas generation as the region shifts away from coal- and oil-fired power plants
- ▶ Retirements of coal- and oil-fired power plants and nuclear plants
- ▶ Growth of renewable resources, propelled by state initiatives
- ▶ Growth of resources that reduce consumer demand from the regional grid: energy-efficiency (EE) measures, such as energy-saving lightbulbs, and “behind-the-meter” (BTM) solar panels installed at homes and businesses on the distribution systems managed by local utilities

### The Dash to Gas

The two most significant of these trends are the increasing use of natural gas and the retirement of power plants that use fuels other than natural gas. By far the biggest factor is the “dash to gas.” Two decades ago, the regional power system derived most of its electricity from generators with fuel stored on site: coal, oil, and nuclear. Today, coal-fired, oil-fired, and nuclear power plants are still a significant portion of the region's generation fleet, but natural-gas-fired generators make up nearly half the fleet and use “just-in-time” fuel deliveries.

In 2000, oil- and coal-fired power plants produced 40% of the electricity generated in New England, while natural gas produced 15%. Starting in 2009, natural gas prices plummeted with the boom in domestic shale gas production. Because ISO New England dispatches the lowest-cost resources first to meet demand, natural-gas-fired generators are used most often. By 2016, natural gas generation had risen to nearly half the electricity produced in New England (49%), while coal and oil dropped to 3% of annual electricity generation, although they still make up nearly 30% of the region's total generating capacity.

While the use of natural gas for both heating and power generation is growing, the natural gas supply infrastructure is not expanding at the same pace, resulting in natural gas supply constraints in winter.<sup>6</sup> Given the region's current and growing reliance on natural gas, limitations on the region's natural gas delivery infrastructure are the most significant component of New England's fuel-security risk.

When pipeline supply constraints occur, all or almost all the available natural gas goes to heating customers. When natural-gas-fired power plants haven't been able to procure the fuel they need to run during recent winters, most of the region's power has come from coal, oil, and nuclear power plants – generators with readily available fuel stored on site – and imports from neighboring power systems with adequate natural gas infrastructure or energy storage in the form of hydroelectric facilities.<sup>7</sup>

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6. ICF International, *New England LDC Gas Demand Forecast Through 2030*, presentation (October 3, 2016), <https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf>.

7. While pumped hydroelectric facilities are considered to have “stored fuel,” in this report the term applies to coal, oil, and nuclear power plants. New England has three pumped-storage hydro facilities that store energy in the form of water in large ponds; when released through turbines, this stored water can provide critical reliability support by generating more than 1,800 MW of energy within 10 minutes, and for up to seven hours. The loss of pumped storage was not studied in this analysis, but pumped storage was included in the dispatch of resources to meet demand.

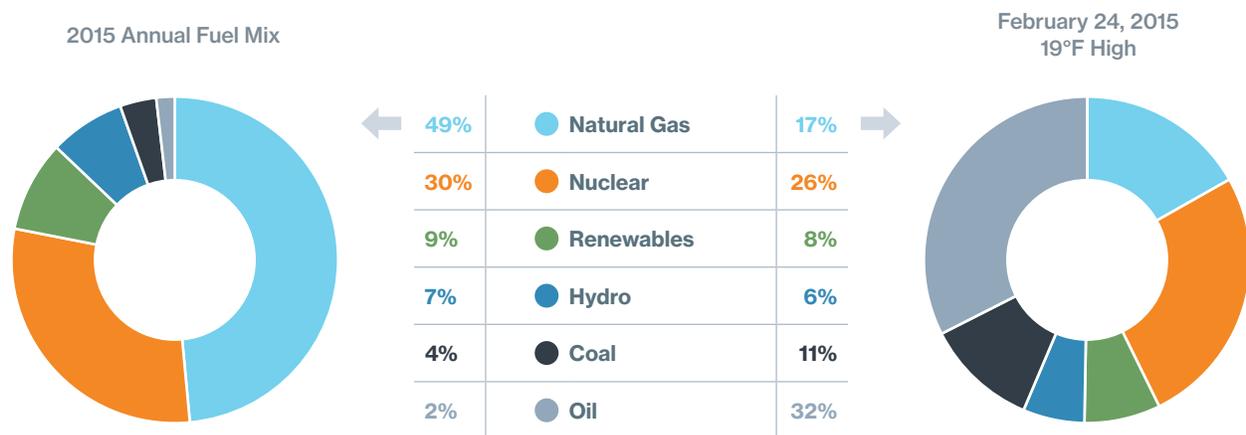
## Retirements of Coal, Oil, and Nuclear Power Plants

The low average annual output from generators using oil or coal masks the major contributions of these aging generators during peak winter and summer days when they may be contributing as much as a third, sometimes more, of the region's power (see Figure 1). These are typically days when summer demand peaks or during winter when generators can't access enough natural gas or the price of natural gas spikes.

### Generators with Stored Fuels Are Key Contributors to Reliability on Cold Days

During winter 2014/2015, combined contributions from oil and coal peaked at over 40% of regional generation on February 24, 2015. Annually, however, these fuels together produced only 6% of New England's generation. Nuclear power, another major non-gas-fired generation source, also made a significant contribution on February 24, 2015. Natural-gas-fired generation, meanwhile, dropped to just 17% for the day, despite providing 49% annually.

**Figure 1: 2015 Annual Fuel Mix Compared with Day of Highest Coal and Oil Generation in 2015**



Source: ISO New England, 2000–2015 Net Energy and Peak Load by Source and Daily Generation by Fuel Type 2015

In 2012, as part of its Strategic Planning Initiative, the ISO identified about 8,300 megawatts (MW) of coal- and oil-fired generators at risk of retirement due to age and economic headwinds.<sup>8</sup> Between 2013 and 2019, nearly 3,000 MW of coal- and oil-fired generation have retired or will retire, leaving about 5,400 MW available but at risk of retirement.

Nuclear power plants represent about 13% of New England's generating fleet but produced 31% of the region's electricity in 2016. Nuclear plants are also retiring in New England and across the country; owners have cited low wholesale electricity prices stemming from low-priced natural gas as the key driver. Vermont Yankee retired at the end of 2014, and Pilgrim will retire by 2019, removing about 1,300 MW of baseload power from New England's fleet.

8. ISO New England, "Strategic Planning Initiative Key Project," webpage (2017), <https://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative>, and *Strategic Transmission Analysis: Generation at Risk of Retirement*, Planning Advisory Committee (PAC) presentation (December 18, 2012), [https://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/prtcpnts\\_comm/pac/mtrls/2012/dec132012/retirements\\_redacted.pdf](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/retirements_redacted.pdf).

In total, the recent and impending retirements of coal-fired, oil-fired, and nuclear power plants add up to the departure by June 2021 of 4,600 MW of generators that use fuels other than natural gas.<sup>9</sup> That's more than 10% of the region's total installed power plant capacity.

The retirements of these aging generators may accelerate as more renewable resources are added to the regional power system. Renewable resources often have the benefit of state and federal financial incentives, as well as long-term contracts sponsored by states seeking to expand their clean energy portfolios. As such, these renewable resources have low costs and can bring down prices in both the energy and capacity markets. These lower prices may drive out coal- and oil-fired generators and nuclear plants dependent on these revenues.

## Growth of Renewable Resources

New England's fleet of renewable resources, powered by water, sun, wind, biomass, and trash, is still small, but wind and solar resources are growing rapidly. The region now has 25 onshore wind farms with more than 1,200 MW of nameplate capacity, up from 375 MW just six years ago, in 2011.<sup>10</sup> State and federal production credits and tax incentives have encouraged this growth.

Additional onshore wind facilities face challenges in development. Most are proposed for construction in remote areas of northern New England where the transmission system was sized to serve the sparse local population, not to carry large amounts of generation. Building the transmission needed to deliver the proposed wind energy to southern New England load centers has proven to be challenging for developers and the region.

The nation's first offshore wind farm, with a 30 MW nameplate capacity, came on line in 2016 off the coast of Block Island, and several companies are competing to build much larger wind farms off the coast of Massachusetts and Rhode Island.

New England has a long history of hydroelectric generation, with hundreds of small dams and several larger facilities. Pumped storage is also a key resource in the region. New England imports about 17% of its energy annually, with much of that coming from Hydro-Québec, which gets almost all its energy from hydro facilities.

The New England states have goals and requirements for clean energy that serve as a major driver of the growth of renewable resources in the region. Massachusetts, Connecticut, and Rhode Island issued a request for clean energy proposals in 2016 and have selected proposals for 460 MW.<sup>11</sup> Massachusetts is also implementing legislation that calls for the equivalent of about 1,200 MW of clean energy, including hydro from Canada, by 2022.<sup>12</sup> The request for proposals (RFP) for this initiative drew a robust response. The legislation also calls for 1,600 MW of offshore wind by 2027.

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9. The retirements of coal- and oil-fired generators include Salem Harbor (749 MW, shut down in 2011 and 2014), Norwalk Harbor (342 MW, shut down in 2013), Brayton Point (1,535 MW, retired 2017), Mount Tom (143 MW, shut down in 2014), and Bridgeport Harbor 3 (383 MW by June 2021). The nuclear retirements include Vermont Yankee (604 MW, retired 2014) and Pilgrim (677 MW by June 2019). The 4,600 MW also includes a number of smaller generators.

10. *Nameplate* refers to the maximum electricity a resource is rated capable of providing. Most resources' actual output is a smaller percentage of maximum due to outages, and most renewable resources have a lower actual output percentage due to the variability of weather. Actual production from solar photovoltaics (PV) is expected to be about 8% of nameplate (shorter days, more cloud cover in winter), while the output from onshore wind is expected at about 48% and offshore wind at about 53% of nameplate capability.

11. *New England Clean Energy RFP* (<https://cleanenergyrfp.com/>). In November 2015, Massachusetts, Connecticut and Rhode Island, issued an RFP to deliver additional supplies of renewable energy and large-scale hydropower to the New England power system. The three states collectively selected projects representing about 460 MW of clean energy for the New England market. None of the projects included associated transmission to deliver the clean energy supplies to New England load centers. The selection of the winning bids will not be final until contract negotiations and regulatory approvals are complete.

12. Massachusetts Gov. Charlie Baker, "Governor Baker Signs Comprehensive Energy Diversity Legislation," press release (August 8, 2016), <http://www.mass.gov/governor/press-office/press-releases/fy2017/governor-baker-signs-comprehensive-energy-diversity-law.html>. In Massachusetts, *An Act to Promote Energy Diversity* (H. 4568), requires Massachusetts electricity distribution companies to procure 1,600 MW of cost-effective offshore wind energy by 2027 and about 1,200 MW of clean energy generation – baseload hydropower, onshore wind, and solar supported by hydropower, standalone onshore wind, solar, or other Class I renewable resources by 2022. (<https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188>)

The queue of new generation projects seeking to interconnect to the high-voltage power grid operated by the ISO totaled about 13,500 MW as of December 1, 2017. Proposed wind farms make up just over half the proposals, or about 7,300 MW. The queue also includes 1,000 MW of proposed solar (8% of the total) and 400 MW of battery storage (3% of the total). Not all these projects will be constructed; historically, about 68% of the megawatts proposed are never built.

The vast majority of solar photovoltaic (PV) resources in New England are behind the meter, on the distribution system managed by local electric power utilities. A handful of large solar farms are participating in the regional wholesale markets totaling about 50 MW (nameplate); the largest is about 16 MW.

Advanced storage technologies hold promise as resources that can support reliability and the technology is progressing, but cost-effective, advanced energy storage is not yet available at a scale that can ensure reliability on a 35,000-MW power system. Currently, there are about 20 MW of utility-scale battery storage connected to the regional grid; it is unclear at this stage how higher levels of battery storage will affect the frequency and duration of energy shortages.

### **Growth of Energy-Efficiency Measures and Behind-the-Meter Solar**

The New England states are national leaders in energy efficiency, collectively spending more than \$1 billion annually to install energy-efficiency measures in homes and businesses.<sup>13</sup> The efforts are paying off, according to ISO New England's annual energy-efficiency forecast.<sup>14</sup> Total annual energy consumption in New England is tapering off, while winter peak demand is forecasted to decline very slightly from 2017 to 2026.

Behind-the-meter solar photovoltaic installations are also fueling reductions in energy consumption and peak demand. Just five years ago, at the end of 2012, New England had about 250 MW of BTM solar PV installed. At the end of 2016, the number had increased to 1,900 MW, and the ISO's PV forecast projects that by 2024, the region will have 4,400 MW of solar PV (and 4,700 MW by 2026).<sup>15</sup> All this new PV will be installed at homes and businesses on the distribution system, serving to reduce demand for power from the regional power grid. State incentives, particularly in Massachusetts, are helping drive this growth.

By lowering demand from the regional grid, these resources can have the effect of lowering prices as well, diminishing energy and capacity revenues and creating greater financial pressure on more costly resources.

### **Logistical Uncertainties: Fuel Deliveries and Weather**

The region still needs power plants with fuel stored on site, but if they can't get the fuel, they can't run. The uncertainty surrounding New England's fuel-security risk is compounded by an unquantifiable X factor: fuel-delivery logistics.

Fuel-security risks may be more acute in New England than in most other regions because New England is "at the end of the pipeline" when it comes to the fuels used most often to generate the region's power. New England has no indigenous fossil fuels and therefore, fuels must be delivered by ship, truck, pipeline, or barge from distant places.

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13. American Council for an Energy-Efficient Economy, "California Golden Again on Energy Efficiency, Regains #1-State Spot in Tie with 6-Time Winner Massachusetts," press release (September 27, 2016), <http://aceee.org/press/2016/09/california-golden-again-energy>.

14. ISO New England, "Final Energy Efficiency Forecast: 2021-2026" (May 1, 2017), [https://www.iso-ne.com/static-assets/documents/2017/05/final\\_eef\\_2017\\_v2.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/final_eef_2017_v2.pdf).

15. ISO New England, "2017 Final PV Forecast" (May 1, 2017), [https://www.iso-ne.com/static-assets/documents/2017/05/2017\\_solar\\_forecast\\_details\\_final.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf).

The natural gas pipeline system within New England is relatively small, and its access to the rest of the North American pipeline network is limited. In regions with a more robust pipeline network, a failure of a single point on the pipeline system typically can be contained to a local area and routed around, but such an outage in New England will likely create significant impacts.

Limitations or constraints on the fuel-supply chain are not unusual, particularly during bad weather. Winter storms can impede deliveries from liquefied natural gas (LNG) tankers, oil barges, and oil tanker trucks. Low temperatures can increase heating demand for natural gas, oil, and LNG, leaving less for power plants.

Renewable resources can help reduce the demand for energy and the fuels that generate it, but the output of wind and solar facilities depends on the weather and time of day. For example, solar panels can reduce the consumption of natural gas and oil during sunny winter days, so more oil and gas are available later to generate electricity to meet the daily winter peak demand. Solar energy can't help directly with the winter peak, however, because demand peaks after the sun has set.

The timing of fuel consumption and of fuel replenishment can be significant as well. In December, the weather is typically milder. As winter progresses in time and intensity, generators' oil and LNG inventories are depleted and tanks must be refilled rapidly.

Some typical logistical concerns for each fuel are outlined below:

▶ **Natural gas**

- **Pipeline gas.** New England receives natural gas via five pipelines from the west through New York State, and from Canada in the north.

Most of the region's pipeline gas is delivered through New York, where natural-gas-fired generators have the first opportunity to withdraw any surplus natural gas that is not already committed to the gas utilities.<sup>16</sup> Developers are proposing to build more new natural-gas-fired generation in eastern New York. Indian Point Energy Center, a nearly 2,100 MW nuclear station near New York City, has announced it will retire by 2021, which may increase demand for natural gas from generators in New York and could result in reduced supply to New England generators during periods of peak demand.<sup>17</sup> This study does not attempt to quantify these effects, however. Further, construction of additional pipeline capacity in New York will likely prove difficult.<sup>18</sup> Some natural gas is delivered to New England via pipeline from eastern Canadian natural gas fields off Nova Scotia, but most of this supply will be gone by 2020. The primary sources of natural gas for the Canadian Maritimes will become Canaport, a 10 billion cubic feet (Bcf) LNG import, storage, and regasification facility in New Brunswick, and the Maritimes and Northeast (M&N) pipeline. When it is serving Maritimes heating

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16. ICF International, *Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies* (November 18, 2013), [https://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/prtcprnts\\_comm/pac/mtrls/2013/nov202013/icf\\_upstream\\_gen\\_impacts\\_white\\_paper\\_11\\_18\\_2013.pdf](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcprnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11_18_2013.pdf). Eastern Interconnection Planning Collaborative (EIPC), *Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems* (March 9, 2015), p. 149, <http://nebula.wsimg.com/c1a27fe57283e35da35df90f71a63f7a?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1>.

17. New York ISO, *Power Trends: New York's Evolving Electric Grid, 2017* (2017), p. 35, [https://www.google.com/url?q=http://www.nyiso.com/public/webdocs/media\\_room/publications\\_presentations/Power\\_Trends/Power\\_Trends/2017\\_Power\\_Trends.pdf&sa=U&ved=0ahUKEwicr-KkrO7VAhWCwFQKHSc1C1QQFggEMAA&client=internal-uds-cse&usq=AFQjCNG4pCnCu\\_ZyHocx1sQurUb0HzeJ5A](https://www.google.com/url?q=http://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf&sa=U&ved=0ahUKEwicr-KkrO7VAhWCwFQKHSc1C1QQFggEMAA&client=internal-uds-cse&usq=AFQjCNG4pCnCu_ZyHocx1sQurUb0HzeJ5A). Patrick McGeehan, "Cuomo Confirms Deal to Close Indian Point Nuclear Plant" (New York Times [NYT], January 9, 2017), <https://www.nytimes.com/2017/01/09/nyregion/cuomo-indian-point-nuclear-plant.html>.

18. New York ISO, *Power Trends, 2017*, pp. 36–37.

demand, the M&N will be transporting gas from New York or Québec, through New England, to the Maritimes. The result could be less pipeline gas for New England.<sup>19</sup>

- **Liquefied natural gas.** LNG can be an important complement to pipeline gas. It is imported to New England from overseas by ocean-going tankers, typically from Trinidad and Tobago. Most cargoes of LNG need to be contracted and scheduled for months before winter begins; once contracted, the LNG won't arrive for at least five days.

LNG availability can also be affected by global weather or political events.<sup>20</sup> Ocean-going tankers can have difficulty offloading their cargoes at offshore LNG buoys or in ports during winter storms. Cold snaps can result in a sudden drawdown of stored LNG, and the rapid depletion of LNG combined with the region's limited storage facilities can challenge the region's fuel-supply chain, particularly if outages increase the need for LNG.

- ▶ **Oil.** The region's remaining oil-fired power plants get their fuel delivered by oil pipeline, barges, or tanker trucks – but as more and more oil-fired power plants have retired, the delivery supply chain has withered as well. Fewer oil barges and tanker trucks are located in New England. Oil-fired generators may start the winter with full tanks of oil stored on site, but a generator that depletes its oil inventory during a cold snap may not be able to refill its tank promptly if a winter storm prevents tanker trucks from traveling.

In winter, oil delivery trucks may be occupied delivering fuel to heating oil dealers and unavailable for power plant deliveries, or federal restrictions on how many hours drivers can drive may delay deliveries. Rivers may freeze, preventing barges from bringing fuel to generators.

In addition to potential fuel-delivery concerns, environmental restrictions limit how often many power plants can generate electricity using oil. Many of the region's dual-fuel power plants are currently limited to running no more than approximately 30 days per year on oil, and Massachusetts is implementing tighter air emissions regulations.

## Natural Gas Delivery Challenges: Infrastructure Constraints and Contracts

The natural gas system was sized and built to meet the peak demand needs of the local natural gas utilities (also called local distribution companies, or LDCs) serving heating customers. The natural gas utilities contracted for the pipeline capacity, so they have first priority for gas delivery.

On many days, pipeline capacity is sufficient for both the local gas utilities and the natural-gas-fired power plants, but during the coldest weeks of the year, this natural gas delivery infrastructure can't meet all the demand for natural gas for both home heating and power generation. As a result, natural-gas-fired power plants – which typically buy pipeline capacity released by local gas utilities on the secondary market – may not be able to access natural gas.

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19. "Nova Scotia's Deep Panuke natural gas projects drying up" (*The Chronicle Herald*, May 30, 2017), <http://thechronicleherald.ca/business/1473337-nova-scotias-deep-panuke-natural-gas-projects-drying-up>.

20. Erin Ailworth, "Unrest in Yemen may result in local LNG shortage" (*Boston Globe*, May 5, 2012), <http://www.bostonglobe.com/business/2012/05/04/electric-power-plants-threatened-attacks-gas-pipelines-yemen/48P2O2KqNm9sEa2P6dr6IM/story.html>.

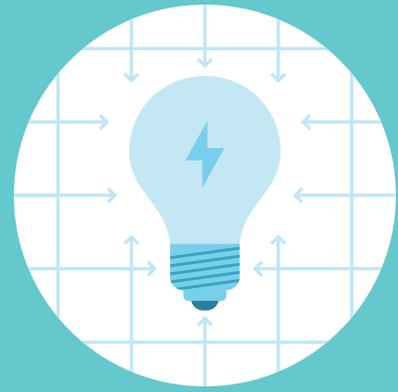
Contracting with pipelines for some level of firm natural gas delivery could solve this problem if the pipeline system expanded to accommodate the increased contracted demand. However, contracting for firm pipeline capacity is costly and requires a long-term commitment. This has been a deterrent for natural gas power plant owners, who have short- to medium-term financial horizons and are a diverse group with diverse market interests.

Contracting for LNG could also help if these contracts are executed before winter arrives. Typically, the ocean-going tankers that transport LNG are committed in the fall for winter delivery, so a sudden or unanticipated need to replenish LNG supplies may go unmet during an unexpectedly bad winter. In addition, as heating demand for natural gas grows, local gas utilities are likely to begin contracting for more of the region's limited LNG storage capacity, leaving even less for natural-gas-fired power plants.

Further, contracting for oil and LNG deliveries can be difficult during winter when other types of customers (e.g., heating, industrial customers) are also seeking urgent deliveries. When power plants don't sign contracts for pipeline gas or LNG, nor enter the winter with full oil tanks, deliveries of oil or LNG when needed cannot be guaranteed.

The retirements of power plants with stored fuel, tightening emissions restrictions, and the reliance on a fuel that may not be available when needed most are all challenging New England's power system. Logistical and time- and weather-dependent fuel-delivery uncertainties introduce additional potential for fuel-security risks that could degrade the reliability of the regional power system.

# Operational Fuel-Security Analysis



The shift away from generators with on-site fuel to natural-gas-fired generators relying on “just-in-time” fuel delivery has exposed the limitations of New England’s existing fuel infrastructure and has heightened the region’s fuel-security risks.

As the system continues to change, it is incumbent on ISO New England, as the reliability coordinator for New England’s six-state power grid, to assess the potential operational impacts these risks may pose in the near future.<sup>21</sup>

## Study Description

The ISO launched this operational analysis to quantify the region’s future fuel-security risk – that there may be times when sufficient fuel is not available for power plants to generate all the electricity required to meet consumer demand and maintain power system reliability during the entire winter of 2024/2025.

The study determined whether or how often the region would run short of natural gas and oil during an entire 90-day winter and calculated how often the resulting energy shortfalls would require the ISO to employ emergency actions, up to and including rolling blackouts.

## Resources and Key Variables

The study developed a wide range of hypothetical scenarios of a regional power system composed of different resource combinations, incorporating the same types of resources and fuels as those in New England’s fleet today:

- ▶ Natural-gas-fired generators
- ▶ Oil-fired generators
- ▶ Dual-fuel generation (power plants that can use natural gas or oil stored on site; most use natural gas as their primary fuel and oil as their backup fuel)
- ▶ Renewable resources, including on- and offshore wind, solar, biomass, and behind-the-meter solar photovoltaics
- ▶ Energy-efficiency measures
- ▶ Nuclear power plants
- ▶ Hydro generation
- ▶ Pumped-storage generation
- ▶ Imports

21. North American Electric Reliability Corp, “Reliability Coordinators,” webpage (2016), <http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx>.

The exception was the region's remaining coal-fired power plants, which were assumed to be retired by 2024.

Five key factors affecting power system operations were the variables in each scenario:

- ▶ **Retirements** of generators that use fuels other than natural gas (coal and oil)
- ▶ **Imports** of electricity over transmission lines from neighboring power systems in New York and Canada
- ▶ Level of **renewable resources** on the system
- ▶ Level of **LNG injections** into the region's natural gas delivery and storage infrastructure
- ▶ **Dual-fuel generators' oil tank inventories** – that is, how often the oil tanks on site at dual-fuel power plants are filled and refilled throughout a 90-day winter

The analysis modeled 23 possible future resource-mix combinations, including four high-impact outages of key energy facilities, during December, January, and February, of winter 2024/2025.<sup>22</sup> The study assessed each scenario's physical capabilities to meet demand and required reserve levels by calculating the amount of fuel needed to generate all the electricity required. The study then compared the amount of fuel needed with the actual level of fuel – wind, sun, hydro, other renewables, nuclear, imported electricity, natural gas delivered via pipeline, and oil and LNG stored in tanks – the region's fuel infrastructure could deliver to each hypothetical resource mix.

## The Need for Emergency Actions

The study determined whether or how often the region would run short of fuel and calculated how often the resulting energy shortfalls would require emergency actions, up to and including rolling blackouts. For each scenario with insufficient fuel to generate all the electricity needed to meet demand, the study model dispatched the resources providing reserves. If demand still existed after the reserves were depleted, the study calculated the frequency, magnitude, and duration of emergency operating procedures needed to maintain system balance.

The need to implement any emergency operating procedure is an indicator of system stress. System operators must take these actions to protect the region's high-voltage power system. The actions range from smaller steps invisible to the public up to load shedding (rolling blackouts). Load shedding would be implemented as a last resort to avoid an imbalance of supply and demand that could lead to cascading, uncontrolled outages and significant damage to the region's power grid that could spread to other regions.

## Caveats

This is a unique study in that it highlights the vital role of fuel security in power system operations. It differs from previous studies in three key ways:

- ▶ **First**, it quantifies operational risk by measuring energy shortfalls and levels of system stress.
- ▶ **Second**, it focused on the availability of energy over the course of an entire winter – 90 days during December, January, and February, rather than looking at capacity availability on just one winter peak day.
- ▶ **Third**, it is not an economic study that considers fuel costs or prices.

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<sup>22</sup> The study analyzed a wide range of scenarios but did not model every possible future resource combination.

Furthermore, this analysis did not examine the impacts of additional natural gas pipeline capacity on a winter peak day when most or all the pipeline capacity will be used to serve heating customers, not power plants. This study assumed that only four incremental pipeline capacity expansions, already underway or in advanced planning as of summer 2017, would be in service by 2024/2025.<sup>23</sup> This additional capacity is designated for local gas utilities that contracted for the expansion in expectation of growth in demand for natural gas for heating.

This *Operational Fuel-Security Analysis* differs from the economic studies conducted by the ISO at the request of stakeholders. The economic studies consider the wholesale electricity costs that could result from various resource mixes and their fuel costs. The model in this fuel-security analysis does not directly consider fuel costs as a factor in meeting regional demand each day. An unrelated economic study the ISO conducted recently for the New England Power Pool (NEPOOL) should not be confused with this fuel-security analysis.<sup>24</sup> This analysis also differs from the ISO's planning studies in that it focuses on operational impacts and does not evaluate potential solutions.

While this study doesn't directly consider fuel costs or prices, it does assume that the electricity and fuel markets send price signals sufficient to make full use of the existing electricity and fuel infrastructure as needed. For example, New England electricity prices would be high enough on a given day to attract sufficient imports from neighboring areas to meet New England's needs. Further, the Forward Capacity Market's pay-for-performance requirements, which are designed to provide incentives for resources to perform when needed, are scheduled to be phased in starting June 1, 2018, but the impacts, and the timing of the impacts, are uncertain.

The future hypothetical resource combinations envisioned in each scenario may never materialize, while some may come closer to the future power system than others. Further, power system conditions seldom behave in as orderly a fashion as a study model. Conditions can vary tremendously every day, and even every hour, on a large power grid.

Imports may surge or lag, the output of renewables may be more or less than the average output used in the study, and multiple generators can trip off line on the same day.<sup>25</sup> Fuel replenishment may be easier or more difficult depending on winter conditions, the LNG market may be affected by global conditions that hinder or expedite deliveries, and natural gas delivered via pipeline may or may not be available in sufficient quantities. Higher energy market prices could convince some older generators not to retire, sooner-than-expected advances in technology could change and improve how the system operates, or a combination of some of these factors could alter the future power system.

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23. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), <https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf>. Assumed the following additions: Algonquin Incremental Market (AIM) expansion, 0.345 Bcf/d pipeline capacity, in service January 2017; Atlantic Bridge, 0.13 Bcf/d, planned in service 2017; Connecticut Expansion, 0.07 Bcf/d, planned in service 2017; Continent-to-Coast, 0.11 Bcf/d, planned in service 2017.

24. The *2016 Economic Study Results: Peak-Gas-Day/Hour Capacity and Energy Analysis* (August 1, 2017) ([https://www.iso-ne.com/static-assets/documents/2017/08/a3\\_2016\\_economic\\_study\\_natural\\_gas\\_capacity\\_and\\_energy\\_analysis\\_rev1.pdf](https://www.iso-ne.com/static-assets/documents/2017/08/a3_2016_economic_study_natural_gas_capacity_and_energy_analysis_rev1.pdf)) was a continuation of the *2016 Economic Study: NEPOOL Scenario Analysis* (July 24, 2017) ([https://www.iso-ne.com/static-assets/documents/2017/07/draft\\_2016\\_phase1\\_nepool\\_scenario\\_analysis\\_report.docx](https://www.iso-ne.com/static-assets/documents/2017/07/draft_2016_phase1_nepool_scenario_analysis_report.docx)). The ISO conducts economic studies at the request of stakeholders as part of the regional system planning process. The NEPOOL natural gas study evaluated the natural gas system's ability to meet the requirements of natural-gas-fired generation in the stakeholder-designed scenarios used in the *2016 NEPOOL Scenario Analysis*. The NEPOOL study assumed that the natural gas system will have no planned or forced outages and the gas delivery system will be at full capacity on the summer and winter peak days in 2025 and 2030, while this *Operational Fuel-Security Analysis* quantifies the risks associated with insufficient fuel during the 90-day winter period. The NEPOOL analysis also differs from this fuel-security analysis in terms of metrics, scenarios, and the variability in power system inputs.

25. On August 11, 2016, during a hot and humid spell that pushed up demand, a large generator tripped off line followed by several more. In all, nearly 4,300 MW of resources dropped off line unexpectedly over the course of the day. System operators implemented the first two actions of Operating Procedure No. 4 (OP 4), which allowed the system to operate with less than the required level of 30-minute reserves and to dispatch demand-response resources that curtailed their energy consumption. (<http://isonewswire.com/updates/2016/10/19/summer-2016-recap-uneventful-until-august.html>)

Some New England states are pursuing significant, economy-wide reductions in carbon emissions by 2050. While these efforts can be expected to put upward pressure on demand for electricity as the transportation and heating sectors turn away from fossil fuels, the pace and future effects of these policies on the power system are still unclear.

While the study calculated the number of hours of emergency actions each scenario would require as an indicator of system stress, the resulting numbers should not be construed as a precise prediction. Rather, the results provide a basis for comparing the fuel-security risk of each of the hypothetical resource combinations, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories at dual-fuel generators, imports, and renewable resources. Some resource combinations would result in more hours of emergency actions, while others would require fewer actions or none.

## **Electricity Demand in Winter 2014/2015 and Winter 2024/2025**

The study evaluated each scenario's fuel-security risk throughout the 90-day winter of 2024/2025 based on the levels of consumer demand experienced in December, January, and February of winter 2014/2015.

Winter 2014/2015 serves as the baseline because, while it did not have the coldest days recorded in the past 10 years, it had the most sustained cold as measured by heating-degree days (HDDs).<sup>26</sup> Thus, it provided a wider perspective on the cumulative use of oil and LNG inventories over a full 90 days and the need to replenish these inventories as cold weather persists. If the region experienced colder winters than 2014/2015, as is possible (four winters in the past 38 years were colder, as measured by HDDs), the number and duration of energy shortfalls found in this study would be magnified. A winter with this level of sustained cold has a probability of occurring approximately once every 8 years.

ISO New England is responsible for the reliability of New England's power system under all types of system and weather conditions. No one knows before winter begins how extreme the weather will be. The ISO, the owners of generators and other equipment on the New England power system, and the fuel-supply chains that generators depend on must be prepared for a long, cold winter – perhaps as cold as 2014/2015, or even as cold as one of the winters with more heating-degree days than 2014/2015.<sup>27</sup> While the weather plays a primary role in operating conditions, so do other key variables, as highlighted in this study.

The hourly demand levels from winter 2014/2015 were adjusted to reflect the ISO's forecast for slightly higher net peak demand in extreme winter conditions in 2024/2025.<sup>28</sup> All the scenarios incorporate the ISO's latest forecasts for the effects of energy efficiency and distributed PV generation, which reduce the amount of electricity needed from the larger regional grid.

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<sup>26</sup>. A degree day is a measure of heating or cooling and an indication of a building's demand for energy (fuel consumption). A zero-degree day occurs when no heating or cooling is required. As temperatures drop, more heating days are recorded; when temperatures rise, more cooling days are recorded. The base point for measuring degree days is 65 degrees Fahrenheit (°F). Each degree of a day's mean temperature above 65°F is counted as one cooling-degree day, while each degree of a day's mean temperature below 65°F is counted as one heating-degree day. A day's mean temperature of 90°F equals 25 cooling-degree days, while a day's mean temperature of 45°F equals 20 heating-degree days.

<sup>27</sup>. Number of HDDs for 2014/2015: 3,551. Coldest winters as measured by HDDs: 1993/1994: 3,678; 2002/2003: 3,611; 1980/1981: 3,573; 1981/1982: 3,568.

<sup>28</sup>. ISO New England, *2017–2026 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 1, 2017), [https://www.iso-ne.com/static-assets/documents/2017/05/2017\\_celt\\_report.xls](https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls).

While actual power grid conditions could change earlier or later than the target year, the study used winter 2024/2025 as the target for several reasons. By winter 2024/2025, the outlook for power system reliability is uncertain. Given the pace of power system transformation and increasing economic pressures on the remaining oil, coal, and nuclear power plants, more retirements are expected in the next decade. The years until winter 2024 give the region time to address these challenges but don't provide any buffer to defer decisions about the region's fuel-security risk.

## Overview of the Scenarios

The study's reference case incorporated each of the five key variables at levels that can reasonably be expected to materialize in New England given current trends. Several "combination" scenarios also represent a range of resource and fuel types that could realistically be expected to be available in the 2024/2025 timeframe. The reference case provides a baseline for all the other scenarios, which included differing levels of the five variables.

Eight scenarios adjusted just one of the five variables at a time, up or down from the reference case level, to assess the relative impact of each variable. For example, two scenarios were developed to show the effects of differing LNG levels. Four variables – retirements, electricity imports, renewables, and dual-fuel oil inventories – were held constant, and in one scenario, LNG injections were *increased* above the reference case level, and in the other scenario, they were *decreased* below the reference case. Retirements and renewables were exceptions – neither was adjusted down from the reference case level. And for retirements, a higher level represented a greater loss of resources and is considered less favorable, while with all other variables, a higher level is considered positive or favorable.

Two scenarios represented the most and least favorable levels of each variable to show the best- and worst-case outcomes. For the best-case scenario, all five variables were modeled at levels that would minimize fuel-security risk, including low retirements. For the worst-case scenario, all five variables were modeled at less-favorable levels that would raise fuel-security risk, including greater retirements.

The four "combination" scenarios adjusted more than one variable to represent a blend of outcomes, including cases with less LNG, more LNG, higher retirements of non-gas-fired generators, and retirements of all at-risk non-gas-fired power plants coupled with very high levels of renewables and imports.

Eight high-impact scenarios assessed the effects of an outage of four major energy facilities for the entire winter on the reliability of the power system. The impacts were assessed on a system represented by the reference case and also by the combination case with the highest levels of retirements and renewables. The outages of the following key energy facilities were studied:

- ▶ A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel to generators with a combined capacity of about 7,000 MW
- ▶ The loss of Millstone Nuclear Power Station in Connecticut, one of the region's remaining two nuclear facilities, eliminating 2,100 MW of baseload power
- ▶ The loss of the Canaport LNG import and regasification facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d of gas that could be injected into the New England and Maritimes pipeline systems

- ▶ A disruption to the Distrigas LNG import, storage, and regasification facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW gas-fired Mystic 8 and 9 generators and as much as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d)

## Key Resource Assumptions

Several key assumptions about New England's future energy landscape are common to all the scenarios.

### Natural Gas Supplies

On the basis of a study ICF International conducted for the ISO on probable natural gas infrastructure expansions in the region, this fuel-security analysis assumed that the region's natural gas supply infrastructure will have been expanded only incrementally beyond its current capability by 2024, including a recently completed pipeline expansion and three smaller expansions underway.<sup>29</sup> The ICF study found that these four planned or recently completed expansions will total 0.65 Bcf by 2018, increasing New England's pipeline capacity from 4.04 Bcf/d to 4.69 Bcf/d over the five pipelines bringing natural gas into New England from New York and Canada.

The pipeline expansions are sized to meet the future capacity requirements of the natural gas utilities that contracted for the added capacity; pipelines aren't built speculatively to accommodate potential future customers, such as natural gas generators. As such, any incremental pipeline capacity is expected to be used by natural gas utilities to serve their growing customer base.

Two natural gas fields off the coast of Nova Scotia – Sable Island and Deep Panuke – are expected to be depleted before 2025. This fuel-security study assumed that the depletion of these gas fields would leave the Canadian Maritimes with just two sources of natural gas: Canaport and the Maritimes and Northeast pipeline that carries gas between Canada and Maine.

The study assumes that by 2024/2025, on most days, some natural gas will flow via pipelines from New York or Québec, through New England via the M&N pipeline, to the Maritimes to serve heating customers.<sup>30</sup> Pipeline gas will be used more often than Canaport's LNG because natural gas is typically cheaper than LNG. On high-demand days when pipeline gas is insufficient, higher-priced LNG from Canaport or other sources will be needed to augment the pipeline gas supply. Under these conditions, the M&N pipeline will function as an internal distribution system carrying gas from the west to Canada, rather than as a separate source of gas from Canada to New England. Considering this shift, the study treated the M&N pipeline's 0.833 Bcf/d capacity as an internal regional pipeline rather than as a source of natural gas from outside New England.

As a result, the pipeline infrastructure capable of delivering natural gas into the region in 2024/2025 would stand at 3.86 Bcf/d over four pipelines from New York and Québec: Algonquin Gas Transmission (1.9 Bcf/d from New York), Tennessee Gas Pipeline (1.4 Bcf/d from New York), Iroquois Gas Transmission System (0.26 Bcf/d from New York), and Portland Natural Gas Transmission (0.3 Bcf/d from Québec).

The study assumed that LNG will be imported to three sources in 2024/2025: Canaport, Distrigas, and the Northeast Gateway Deepwater Port buoy off Gloucester, MA.

29. ICF International, *Forecast of Near-Term Natural Gas Infrastructure Projects*, presentation (October 3, 2016), <https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-infrastructure-forecast-03-oct-2016.pdf> (Natural Gas Infrastructure Forecast).

30. The study did not factor in demand for natural gas to serve power plants in the Maritimes.

The maximum injection capability from each of the LNG facilities is 1.2 Bcf/d from Canaport, 0.4 Bcf/d from the Northeast Gateway buoy, and a maximum injection of 0.435 Bcf/d into the interstate pipeline system and the local gas utility system from the Distrigas facility. The maximum LNG that can be injected into the Canadian Maritimes and New England interstate natural gas pipeline systems is 2.04 Bcf/d.<sup>31</sup>

Combined, the expected pipeline capacity of 3.86 Bcf/d, plus the 2.04 Bcf/d maximum LNG that could be regasified and injected into the pipeline systems serving New England and the Maritimes, totals about 5.9 Bcf/d.

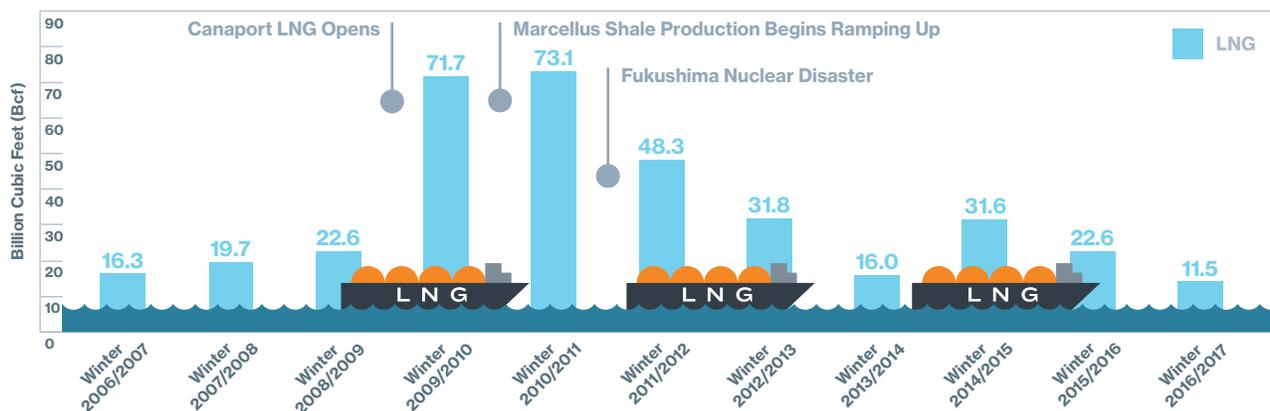
Natural gas deliveries from LNG facilities to New England pipelines have varied over the past 15 years, from none on one day in December 2016 to the maximum delivery observed at any one time of 1.25 Bcf on one day in February 2016.<sup>32</sup> The maximum amount of regasified LNG injected into the region's pipeline system in any scenario in this study was 1.5 Bcf/d, and the least was 0.65 Bcf/d in a scenario with an outage at Canaport.

Tracking LNG scheduled deliveries to the region's pipelines over an entire, 90-day winter season, the lowest level of LNG deliveries in the past 11 years arrived during the mild winter of 2016/2017, at 11.5 Bcf. The highest was 73.1 Bcf in winter 2010/2011, with the second-highest in 2009/2010, at 71.7 Bcf. The region's imports of LNG during winters going back to 2006/2007 are illustrated in Figure 2.

### LNG Deliveries to New England Hinge on a Global Market and Winter Weather Predictions

Regional LNG deliveries vary from winter to winter for a variety of reasons, including the level of firm contracts as well as global LNG futures prices. Forecasts for a severe winter can also cause futures prices to increase. When New England's forward prices are high, destination-flexible LNG spot cargoes are likely to be attracted to the region. The primary driver for the significant increase in LNG deliveries in the winters of 2009/2010 and 2010/2011 was the new Canaport LNG import terminal in New Brunswick. Rising Marcellus shale gas production, starting in the 2010 timeframe, has lowered natural gas prices for most of the year, making LNG less competitive on price, on average. The Fukushima nuclear plant meltdown in 2011 caused a significant increase in Japan's use of LNG.

Figure 2: Winter LNG Deliveries to New England Interstate Pipelines



Note: Graph does not include the Mystic 8 and 9 gas-fired generators' fuel supply from the LNG facility.

Source: Data from NatGas Analyst Tool by Genscape, a part of DMG Information (DMGI), www.genscape.com, based on scheduled deliveries posted to gas-industry bulletin boards

### Natural Gas Demand

A key factor in this study is how much natural gas will be left over for power generators after natural gas distribution companies have served their heating customers. A second study conducted in 2016 by ICF International for the ISO projected how much natural gas the gas utility companies will need in

31. The Distrigas LNG injection capacity does not count any LNG that goes directly to supply the Mystic 8 and 9 generators because this LNG is not available for injection into the interstate or local distribution pipeline systems and is not available to other generators. Likewise, the LNG used to supply Mystic 8 and 9 is not counted under the LNG caps modeled in the study scenarios.

32. This excludes any LNG directed to Mystic 8 and 9.

2024/2025.<sup>33</sup> This ICF study found that in winter 2014/2015, natural gas demand for heating totaled 4.4 Bcf on the winter peak day. The study also forecasted that on the coldest winter day, peak demand from local gas utilities alone could reach 5.45 Bcf/d by 2025.

Total demand for the entire year from gas utilities was 515 Bcf in 2014. The ICF study concluded that the annual demand for natural gas from local gas utilities will rise at an average of just under 2% per year, up to 591 Bcf per year in 2025 and 620 Bcf per year in 2030. As local gas utilities continue converting customers to natural gas heating, this demand will put additional pressure on gas availability for electric generation.

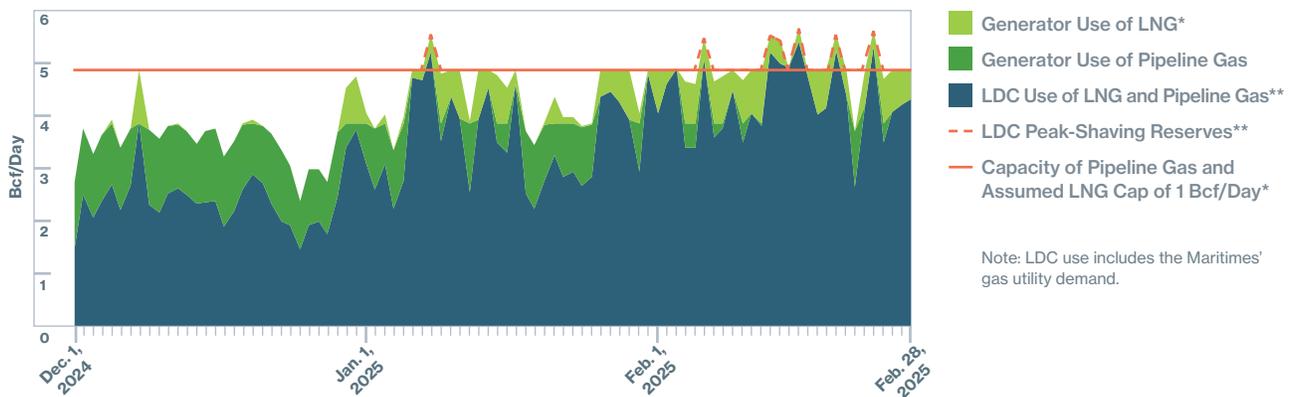
While Canada is moving to retire all its coal- and oil-fired power plants by 2030, this study does not attempt to project or include the potential impacts of additional gas demand from the electric generation sector in the Canadian Maritimes on New England's fuel security. The Maritimes' gas utility demand was included because, by 2024/2025, its heating demand is likely to be served entirely by Canaport or by importing natural gas through New England via the M&N pipeline. Either way would result in less natural gas for New England.

Figure 3 shows the effect of heating demand by local gas utilities in New England and the Maritimes on the availability of natural gas for generators, from both pipelines and from LNG.

### Natural Gas Availability for Power Plants Is a Function of Heating Demand for Natural Gas

The growing use of natural gas to meet heating needs on the coldest days in New England and the Canadian Maritimes can limit the availability of natural gas, from both pipelines and LNG facilities, for New England's power plants. Local gas distribution companies (LDCs) have priority contracts with natural gas pipelines to acquire gas for their heating customers. As shown here, on some days during winter 2024/2025, the generators' need for fuel is projected to reach or exceed the region's total amount of pipeline capacity plus the assumed maximum LNG injection of up to 1 Bcf/d in the reference case. Fully meeting electricity demand on these days will hinge on the fuel inventories of non-gas-fired power resources, particularly oil (as illustrated in Figure 5 on page 36). On days when LDC demand stresses the natural gas infrastructure capacity, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities. The regulated LDCs have purchased the LNG stored in these tanks, which cannot be sold to power plants or other parties. While these reserves aren't directly available to generators, they may sometimes make more natural gas available during the operating day.

**Figure 3: Winter 2024/2025 Supply of Pipeline Gas and LNG Compared to Use**  
(Reference Case)



\*Graph does not include the Mystic 8 and 9 gas-fired generators' fuel use or supply from the LNG facility.

\*\*Per data from ICF International, *New England LDC Gas Demand Forecast Through 2030* (December 14, 2016, presentation to Planning Advisory Committee) and *The Future of Natural Gas Supply for Nova Scotia* (March 28, 2013, for Nova Scotia Department of Energy).

33. ICF International, *New England LDC Gas Demand Forecast Through 2030*, PAC presentation (December 14, 2016), <https://www.iso-ne.com/static-assets/documents/2016/12/iso-ne-ldc-demand-forecast-03-oct-2016.pdf>.

## Coal-Fired Generation

The study assumed that New England would have no more coal-fired power plants in winter 2024/2025.

## Renewables

For each scenario, the study assumed the region would have at least 6,600 MW (nameplate capacity) of renewable resources in winter 2024/2025. This reflects the region's current amounts of wind (1,200 MW of onshore wind, 30 MW offshore) and other existing renewables, such as biomass, refuse, and solar resources (960 MW), plus all the behind-the-meter solar PV forecasted to be installed by 2024.

These assumptions were developed by studying proposed projects, as well as initiatives by the New England states. For example, the ISO's 2017 PV Forecast anticipates the region will have 4,430 MW of installed nameplate PV capacity through 2024.<sup>34</sup> The ISO Interconnection Queue currently includes proposals for about 4,600 MW of onshore wind and about 2,700 MW of offshore wind (as of August 15, 2017).<sup>35</sup> However, historically, about 68% of proposed megawatts are never constructed.

The model also incorporated into all scenarios the ISO's forecasts for growth of energy-efficiency measures. The ISO's forecast estimates that passive EE measures will lower peak demand by 3,907 MW in winter 2024/2025, to 20,761 MW in extreme winter weather. Winter peak demand is expected to decline about 0.7% per year over the 10-year planning period.<sup>36</sup>

Some scenarios assumed higher levels of offshore wind and behind-the-meter solar because these resources appear to have the greatest growth potential, driven by state policies and incentive programs. Onshore wind was held at the current level throughout the study timeline, given the transmission expansion that would be required to develop more onshore wind farms. However, these assumptions are not prescriptive; the megawatts modeled for one type of renewable resource in some scenarios could also be coming from other types of renewable resources, or even EE measures.

Several scenarios raised the level of renewables from 6,600 MW to 8,000 MW by adding nearly 1,400 MW of offshore wind by 2024. The cases with 8,000 MW of renewables also raised imports by 1,000 MW, to 3,500 MW, reflecting the assumption that an additional, hypothetical transmission line will be built by 2024 to address state goals for clean energy from Canada or New York.

One combination case raised renewables to 9,500 MW, the highest level of renewable resources assumed in this study. This scenario assumed that the region will have 2,000 MW of offshore wind by 2024, and that behind-the-meter solar PV will grow at a faster pace than currently projected, adding 900 MW of PV to the current forecast of 4,430 MW, for a total of 5,330 MW of BTM PV.

The cases with 9,500 MW of renewables also assumed imports of clean energy will grow by 1,000 MW as the result of higher imports over the new, hypothetical transmission tie. Adding the renewables and the 1,000 MW of additional imports brings the total clean energy assumed in this scenario to 10,500 MW (nameplate), or nearly a third of the region's current generating capacity.

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34. ISO New England, *Final 2017 PV Forecast*, presentation (May 1, 2017), [https://www.iso-ne.com/static-assets/documents/2017/05/2017\\_solar\\_forecast\\_details\\_final.pdf](https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf).

35. ISO New England, "Interconnection Request Queue," webpage (August 2017), <https://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue>.

36. ISO New England, *2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)* (May 1, 2017), [https://www.iso-ne.com/static-assets/documents/2017/05/2017\\_celt\\_report.xls](https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls).

Table 1 shows the assumptions for the renewables included in the reference case, the scenario with more offshore wind and imported clean energy, and the scenario with the highest level of renewables.

**Table 1: Renewable Resource Assumptions**

Case Scenario	Renewables Total MW (rounded)	Breakdown MW			
		 Onshore Wind	 Offshore Wind	 PV	 Other Renewables
2017	4,600	1,200	30	2,400	960
Reference Case	6,600	1,200	30	4,430	960
More Renewables	8,000	1,200	1,400	4,430	960
Max Renewables	9,500	1,200	2,000	5,330	960

## Imports

Thirteen high-voltage transmission lines connect New England to neighboring power grids in New York and Québec and New Brunswick, Canada. Most of the time, New England is importing power over these lines from its neighbors.

Some of the New England states' goals that call for more clean energy, including from Canada and New York, are incorporated into some scenarios that increased imports above the 2,500 MW reference-case level. These additional imports, at 500 MW and 1,000 MW, raised total imports to 3,000 in one scenario and 3,500 in several other scenarios. The additional energy was assumed to be composed of clean energy over a hypothetical new transmission line from Canada or New York. Most of those imports would likely be coming from Québec most of the time.<sup>37</sup>

New England and its neighbors experience winter weather at the same time and, in fact, the demand for power in Québec and New Brunswick peaks in winter. As a result, their imports to New England could be limited as they serve their own populations. This study does not attempt to quantify these effects, however.

<sup>37</sup> The study also assumed that New England would receive 500 MW of emergency imports from its neighbors during times of system stress when Operating Procedure No. 4 was implemented.

## Methodology

The study modeled each scenario's future fuel-security risk in several steps, including:

- ▶ Calculating the amount of electricity required to meet demand each hour of a 90-day winter, from December 1, 2024, through February 28, 2025
- ▶ Calculating how much natural gas would be available after all heating demand were served, as well as the levels of oil stored on site at oil-fired and dual-fuel power plants
- ▶ Calculating how much electric energy could be generated by each fuel type
- ▶ Comparing the amount of fuel required with the level of fuel the region's fuel-delivery system could supply in each hypothetical scenario
- ▶ Assessing the magnitude and duration of emergency actions required, up to and including rolling blackouts after all operating reserves were depleted, if the fuels available were not sufficient to meet demand

The study model was based on winter conditions when oil and gas fuels were expected to be tight, so demand was met by dispatching non-oil-fired and non-natural-gas-fired generators first. Resources in this category included renewables, such as on- and offshore wind, solar PV, other renewables (e.g., biomass, refuse, landfill gas); nuclear; and hydro, including pumped storage. Next in the dispatch order were imports, then natural-gas-fired generators. If all power plants were already operating at full capability, and more demand for power still needed to be served, dual-fuel generators with stored oil would be dispatched. Finally, oil-only generators would be used.

If not enough stored oil and LNG were available to generate all the power needed to meet the remaining demand, the study calculated the frequency, magnitude, and duration of the emergency actions needed to maintain system balance and meet reliability requirements.

## Metrics: How System Stress Was Measured

The study quantified how often energy shortfalls – that is, insufficient fuel to generate all the electricity needed – would occur that would require the ISO to use special procedures to serve consumer demand while maintaining the required level of reserves.

These operating procedures include tools used commonly by the ISO to manage imbalances in supply and demand, as well as emergency actions in more serious conditions. These procedures currently include allowing 30-minute reserves to be depleted, calling on demand-response resources to reduce energy usage, arranging for emergency purchases from neighboring systems, as well as tools used infrequently, such as voltage reductions (also known as brownouts). When deploying these emergency procedures, the ISO can call for the action that will best address the situation at hand; no specific order of implementation is required. If necessary, in an extreme emergency, the ISO can also skip these procedures and implement load shedding immediately.

As system stress intensified in each scenario, the study model progressed through a series of operating procedures, from those that have no impact on electricity service to consumers; to procedures that have minor public impacts, including requests for voluntary conservation and voltage reductions; and then to the depletion of 10-minute operating reserves before finally resorting to load shedding.

Ten-minute reserves are resources that can come on line within 10 minutes to cover for the unexpected loss of a resource. The depletion of 10-minute operating reserves is a significant step – once these reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding. This would be necessary to operate the system reliably and comply with mandatory national standards to avoid uncontrolled outages that could cascade across New England and threaten the entire interconnected system of power grids from the Atlantic Ocean to the Rocky Mountains.

## Required Reserve Levels

ISO New England is required to carry operating reserves to respond to the unexpected loss of any resource on the power system, such as when a large generator trips off line, and almost all the procedures employed in this analysis are used to maintain the required level of reserves. Reserves are insurance – the power plants providing reserves are ready to respond quickly to replace the lost electricity and recover system equilibrium, so that no one loses power and cascading outages are avoided. The North American Electric Reliability Corp., the Northeast Power Coordinating Council, and ISO New England all have requirements for maintaining reserve levels.<sup>38</sup> Beyond the operational risks involved in having insufficient reserves, not meeting these reserve requirements carries consequences, including fines.

The ISO maintains 10-minute operating reserves sufficient to recover from the loss of the largest source of power, whether it's a large generator or transmission line importing power. That's normally between 1,560 MW and 2,250 MW. Thirty-minute reserves – generators that can come on line within 30 minutes – are also required to help the system replenish the 10-minute reserves. Thirty-minute reserves are equivalent to 50% of the second-largest source of supply, which is normally about 625 MW. The depletion of 30-minute reserves typically is the first action taken when the ISO declares Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*.<sup>39</sup> The study assumed 2,300 MW of reserves.

## Operating Procedure No. 4

Operating Procedure No. 4 is the procedure used most often by ISO New England to maintain supply and demand in balance, to avoid violating the 10-minute operating reserve requirement, and to avert the need to implement load shedding. OP 4 includes 11 actions (see Table 2). Most OP 4 actions require no public notification or public response.

The fuel-security analysis assessed the need to implement OP 4 in each scenario in two parts: Actions 1 through 5 and Actions 6 through 11. Actions 1 through 5 are designed to work with transmission owners and other market participants to manage through stressed system conditions.<sup>40</sup> If Actions 1 through 5 are not sufficient to address the problem, the ISO may implement higher-level actions that may be more obvious to the public, such as voltage reductions and urgent appeals for public conservation.

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38. North American Reliability Corp., "Compliance & Enforcement," webpage (2016), <http://www.nerc.com/pa/comp/Pages/Default.aspx>.

Northeast Power Coordinating Council, "Standards," webpage (2017), <https://www.npcc.org/Standards/default.aspx>.

ISO New England, "Reliability Standards: Development and Compliance," webpage (2017), <https://www.iso-ne.com/about/what-we-do/in-depth/reliability-standards-development-and-compliance>.

39. ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (July 5, 2017), [https://iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op4/op4\\_rto\\_final.pdf](https://iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf).

40. In this study, demand-response resources were dispatched to reduce consumption when OP 4 Action 2 was implemented during times of system stress, reflecting the current actions available. However, on June 1, 2018, demand-response resources will be integrated into New England's wholesale energy markets and will be dispatched based on price in the same way generators are dispatched and will not be available as emergency resources. The study did not reflect this change because this will be the first time demand-response resources will be fully integrated into economic dispatch systems, so the price and other aspects of their offers, which affect when they will be dispatched to reduce energy consumption, is uncertain at this time. Real-time emergency generation, dispatched in Action 6, has been in decline due to environmental restrictions and will no longer be available as of June 1, 2018.

Table 2: ISO Operating Procedure No. 4 Actions

OP 4 Action	Action Description
1	<ul style="list-style-type: none"> <li>▶ Implement a Power Caution, which is a public notification that electric power reserves can no longer be maintained using normal measures. Although full reserves are not being maintained, utility personnel will begin to take steps to manage these reserves.</li> <li>▶ Advise resources with a capacity supply obligation (CSO) to prepare to provide capacity and notify “settlement-only” generators with a CSO to monitor reserve pricing to meet their obligations.</li> <li>▶ Begin to allow the depletion of 30-minute reserves.</li> </ul>
2	<ul style="list-style-type: none"> <li>▶ Dispatch real-time demand resources in the amount and location required.</li> </ul>
3	<ul style="list-style-type: none"> <li>▶ Request voluntary load curtailment of market participants’ facilities.</li> </ul>
4	<ul style="list-style-type: none"> <li>▶ Implement a Power Watch, which is a public notification that further steps to manage capacity could affect the public. Issue a public appeal for voluntary conservation.</li> </ul>
5	<ul style="list-style-type: none"> <li>▶ Schedule emergency energy transactions.</li> </ul>
6	<ul style="list-style-type: none"> <li>▶ Implement voltage reductions requiring more than 10 minutes.</li> <li>▶ Dispatch real-time emergency generation.</li> </ul>
7	<ul style="list-style-type: none"> <li>▶ Request generation without a capacity supply obligation to provide energy for reliability purposes.</li> </ul>
8	<ul style="list-style-type: none"> <li>▶ Implement voltage reductions requiring 10 minutes or less.</li> </ul>
9	<ul style="list-style-type: none"> <li>▶ Request activation of transmission customer generation not contractually available to market participants during a capacity deficiency.</li> <li>▶ Request voluntary load curtailment by large industrial and commercial customers.</li> </ul>
10	<ul style="list-style-type: none"> <li>▶ Implement a Power Warning. Issue urgent radio and TV appeal to the public for voluntary conservation. Public appeals are made when other efforts (e.g., emergency purchases, voluntary curtailment, contracted curtailment, and voltage reduction) have been unsuccessful in bringing supply and demand back into balance.</li> </ul>
11	<ul style="list-style-type: none"> <li>▶ Request state governors’ support for ISO appeals for conservation.</li> </ul>

## ISO Operating Procedure No. 7

If OP 4 actions are not sufficient, the ISO may start depleting 10-minute reserves, which leaves the system vulnerable to uncontrolled outages that could cause significant damage to power system equipment and spread to other regions. If the 10-minute-reserves were depleted, implementation of controlled outages – rolling blackouts – could be required to maintain system balance. ISO New England Operating Procedure No. 7 (OP 7), *Action in an Emergency*, is the emergency procedure the ISO follows to implement load shedding.<sup>41</sup>

OP 7 is employed when there is unusually low frequency on the system, equipment overload, a capacity or energy deficiency, unacceptable voltage levels, or any other event the ISO deems an operating emergency in either an isolated or widespread area of the system. The objectives of OP 7 are as follows:

- ▶ Protect the reliable operation of the Eastern Interconnection
- ▶ Restore balance between customers' load and available generation in the shortest practicable time
- ▶ Minimize risk of damage to equipment
- ▶ Minimize interruption of customer service

When OP 7 is implemented, the ISO orders local control centers operated by transmission owners to reduce a specific quantity of system load. They do this by manually opening distribution system breakers to disconnect blocks of customers. Blocks of customers are disconnected and reconnected to the system sequentially, which is why load shedding is sometimes called “controlled outages” and “rolling blackouts.” Rolling blackouts do not affect all customers in the affected area at the same time.

The study calculates the number of times each operating procedure would be needed throughout a 90-day winter in each scenario, the number of hours each procedure would be needed, and the quantity of consumer demand that would go unserved and for how long. These measurements, or metrics, of the number and severity of energy shortfalls illustrate the level of risk involved in each scenario and the relative benefits of the five key variables.

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<sup>41</sup> ISO New England Operating Procedure No. 7, *Action in an Emergency* (January 17, 2017), [https://www.iso-ne.com/static-assets/documents/rules\\_procds/operating/isone/op7/op7\\_rto\\_final.pdf](https://www.iso-ne.com/static-assets/documents/rules_procds/operating/isone/op7/op7_rto_final.pdf).

# Study Results



The study results provide a basis for comparing the fuel-security risk of each of the 23 hypothetical resource combinations analyzed, with a focus on the relative impact of the five key variables: retirements, LNG, oil tank inventories, imports, and renewable resources. Although not all possible resource combinations were studied, the results show that some resource combinations would require more hours of emergency actions, while others would require fewer actions or none. Looking at all the scenarios together (see Figure 4 and Appendix A) provides perspective on the relative levels of fuel-security risk that could be present, depending on how the New England power system evolves, as well as approaches the region can consider to ensure power system reliability. The results should not be construed as a precise prediction.

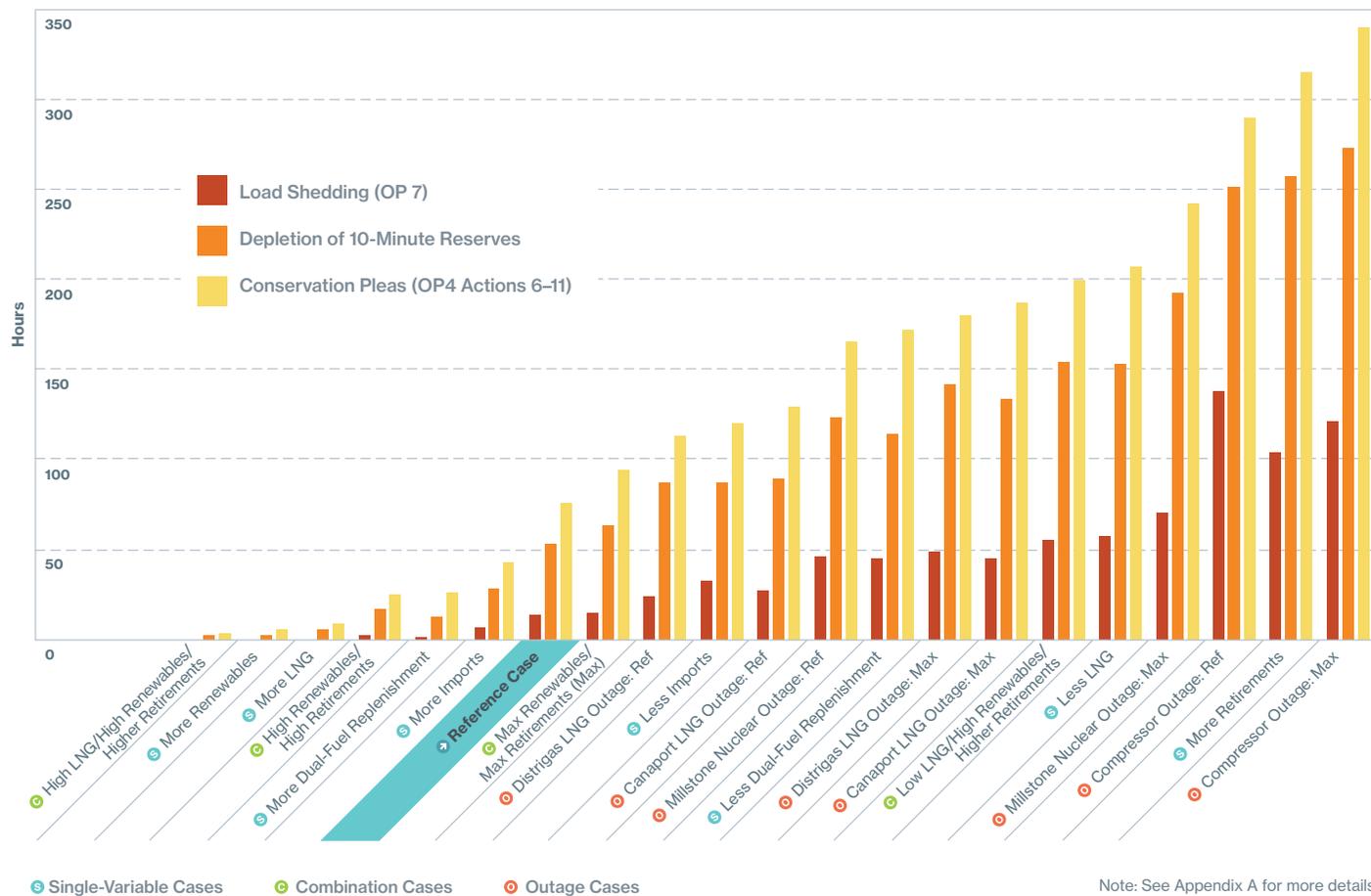
The results show that in most future power system scenarios studied, adequate levels of fuel would not be available throughout the entire winter. Without adequate fuel, the region's power plants would be unable to generate all the electricity needed to meet demand and required reserves – even after accounting for the demand-reducing effects of behind-the-meter solar arrays and energy-efficiency measures. The resulting energy shortfalls would require a range of operating procedures and emergency actions, up to and including load shedding.

Under the wide range of scenarios studied, in all but the most favorable future resource-mix combinations and in all key resource outage scenarios, the study shows that New England's fuel-security risk could become acute by winter 2024/2025, requiring frequent use of emergency actions. In some scenarios, energy shortfalls can be managed with relatively low-impact operating procedures that require no public notification or public actions to maintain system balance. However, most scenarios would require multiple hours of load shedding.

## Current Trends Are Pushing the Power System toward Greater Risk

The major trends affecting the New England power system are moving in a negative direction. This analysis looked at a wide range of future resource mixes to assess the operational impact. All but one of the 23 modeled scenarios (the high [i.e., positive] boundary case, not shown here because it is unlikely to materialize) would lead to some level of emergency actions during winter 2024/2025 (i.e., OP 4 Actions 6–11), as well as hours when the ISO would have to deplete 10-minute reserves to keep the lights on. All but four scenarios would require some level of load shedding (i.e., OP 7). (The low [i.e., negative] boundary case resulted in even more hours of emergency actions but was omitted because it also is unlikely.)

**Figure 4: Hours of Emergency Actions under Modeled Scenarios, Ordered Least to Most**



A summary of the reference case and its results is presented below.

## Reference Case

The reference case is a baseline scenario that represents a future resource mix, including low retirements and moderate levels of other variables, based on reasonable expectations that such levels will develop if the power system's evolution continues on its current path. It does not incorporate state policy goals and requirements for clean energy; other scenarios account for the potential effects of these initiatives on the region's resource mix. While the reference case results discussed below indicate tight operating

conditions, its purpose is to provide a point of orientation for all the other scenarios. Neither the reference case nor any of the other cases are predictors of the future, and none of the scenarios should be viewed as ISO New England's preferred scenario.

## Reference Case Assumptions

- ▶ **Retirements: 1,500 MW.** The ISO projects that the region's 23 remaining coal- and oil-fired generators, with a capability of 5,400 MW, are at risk of retirement. The reference case assumes that by 2024, nine of these power plants, representing 1,500 MW, will be retired. This includes the remaining coal-fired power plants as a result of stricter emissions limits and economic pressures. The retirements in the reference case are in addition to the 4,200 MW recent and pending retirements that will be complete by 2019.

None of the 22 other scenarios reduced retirements below the 1,500 MW reference case level; several increased retirements to 4,500 MW and some would retire all the remaining 5,400 MW of coal- and oil-fired power plants.

- ▶ **LNG injections: 1 Bcf/day.**<sup>42</sup> The maximum amount of regasified LNG that can be injected into New England's pipeline system is about 2.04 Bcf/d. In recent years, the most LNG injected at any one time into New England's pipeline system was 1.25 Bcf/d, on one day in February 2016. The reference case assumed that 1 Bcf is the maximum level of LNG that will be available for both heating and power generation on any given day. Less LNG would be needed on some days, and on some days, more.

- ▶ **Dual-fuel oil tank fill rate: two times per winter period.** Dual-fuel power plants' oil tanks in the reference case were assumed to be filled two times during the 90-day winter: once before the start of the winter and one more time during the winter. For example, a power plant with a 10,000-gallon tank will start the winter with a full tank and then refill it another time, for a total winter oil inventory of 20,000 gallons.

The fill rate of two times was chosen because most generators' oil tanks hold about 10 days' worth of oil, so filling their tanks twice would allow most dual-fuel generators to burn oil for about 20 days. Environmental restrictions currently limit many oil-fired generators in New England to burning oil for no more than approximately 30 days per year. Running for 20 days would put most power plants near their annual limit, a moderate assumption for the reference case. The maximum fill rate in any of the scenarios was set at three times, which would put many generators at their annual limit.

Massachusetts is implementing stricter emissions restrictions that will significantly reduce the amount of time generators in the state could run on oil, but the new Massachusetts regulations are not factored into the future scenarios. Another limitation not factored into the study was the fact that some dual-fuel generators have oil tanks that hold less than 10 days' worth of oil, limiting how long they can run on oil during a cold snap.

- ▶ **Imports: 2,500 MW.** The reference case assumes that the level of imports would be 2,500 MW because on average, over the last five winters, about 2,500 MW was flowing into New England from these neighboring grids just over 60% of the time; most of the rest of the

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<sup>42</sup> As shown in Figure 3, the gas utilities can tap into LNG reserves they have stored at "peak-shaving" facilities when necessary for their purposes. While these reserves aren't directly available to generators, they may sometimes make more natural gas available from other sources during the operating day.

time, about 2,000 MW was imported. The highest observed was about 4,000 MW, just 1% of the time. The study also assumed that if emergency actions were implemented, New England would receive an additional 500 MW of emergency imports from its neighbors, for a total of 3,000 MW of imports in the reference case.

- ▶ **Renewable resources: 6,600 MW.** The reference case assumed that New England’s fleet of renewable resources will total 6,600 MW (nameplate) in winter 2024/2025, with no new wind or hydro imports. This incorporates the region’s current renewable portfolio of about 2,200 MW of wind and other existing renewables such as biomass and refuse and solar resources. To this total, the reference case adds about 4,400 MW of new behind-the-meter solar PV forecasted to be installed by 2024. This estimate of future renewables provides a baseline for comparison from today to scenarios that incorporate additional renewables as planned or required by state legislation.

None of the scenarios in this study reduced renewables below the reference case level of 6,600 MW.

### Reference Case Results

The study found that in a severe winter in 2024/2025, a resource mix represented by the reference case could see multiple hours of emergency actions, including exposure to as many as 14 hours of load shedding spread over six days. Less severe emergency actions (OP 4 Actions 6 to 11) would be required for more than 75 hours, and the depletion of 10-minute reserves – often the last step before load shedding – would be needed for more than 50 hours (see Table 3).

**Table 3: Reference Case Assumptions and Results**

						TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
→ Reference Case (Ref)	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

The study found that, while the assumed maximum available LNG of 1 Bcf/d was not needed every day in the reference case, it was needed on 35 days, and this still would not be sufficient to avoid load shedding or other emergency actions on six days.

Overall, at the slightly higher load levels projected for 2024/2025 but with a cold winter like 2014/2015, the region as a whole would use 62.4 Bcf of LNG over the entire winter for both heating and power generation. This amount is significantly more than the 34.9 Bcf injected into the interstate pipelines, on average, over the past 10 winters and almost double the 31.6 Bcf of LNG injected during winter 2014/2015.

Figure 5 illustrates the daily use of LNG by both gas utilities to serve heating demand and power generators throughout the winter of 2024/2025 in the hypothetical reference case, which assumed a maximum of 1 Bcf/d of LNG injections. The graph also shows declining oil inventories, even in a scenario based on the assumption that dual-fuel oil tanks would be filled twice.

### Emergency Actions Track LNG and Oil Availability

Building off Figure 3 on page 25, this chart takes a closer look at the relationship between regional LNG supply and demand, declining oil inventories as winter progresses, and system reliability. On days when LDC demand for LNG is high, less natural gas is available for generators. When LDC demand stresses the capacity of the natural gas infrastructure, LDCs can tap into LNG reserves stored at their “peak-shaving” facilities. While these reserves aren’t directly available to generators, their use may sometimes make more natural gas available during the operating day. The model shows that as winter progresses, oil inventories decline, while days with high heating demand tend to occur more often. If all or most of the LNG is being used for heating when oil inventories have declined, the region will likely require more frequent emergency actions on the power system (e.g., pleas for energy conservation [OP 4 Actions 6–11] and load shedding [OP 7]).

**Figure 5: Projected Winter 2024/2025 Oil and LNG Use and Emergency Actions**  
(Reference Case)



\* Includes distillate and residual oil. This scenario assumed dual-fuel units’ oil tanks would be filled twice: the initial inventory before winter and one replenishment during winter.

\*\*Graph does not include the Mystic 8 and 9 gas-fired generators’ fuel use or supply from the LNG facility.

\*\*\*LDC use includes the Maritimes’ gas utility demand. LDC data are from ICF International, New England LDC Gas Demand Forecast Through 2030 (December 14, 2016, presentation to Planning Advisory Committee).

## Single-Variable Scenarios

The results are summarized below for the eight favorable and unfavorable scenarios that changed just one variable. Each of the favorable and unfavorable scenarios increased or decreased one key variable from the reference case baseline. (The exceptions were retirements, which were never dropped below the reference case level of 1,500 MW; and renewables, which never dropped below 6,600 MW, and in the case of higher renewables, was assigned a higher level of imports to reflect clean energy imports over a new transmission line.)

The study also included a best-case scenario (*High Boundary*), where all five variables were modeled at levels that would minimize fuel-security risk, and a worst-case scenario (*Low Boundary*) in which all five variables were modeled at less favorable levels that would raise fuel-security risk. At opposite ends of the spectrum, these two cases illustrated the best and worst outcomes but represent future resource combinations that are highly unlikely to materialize. Because they are considered unlikely scenarios, the results of these scenarios are not included in charts but are detailed in the matrix in Appendix A.

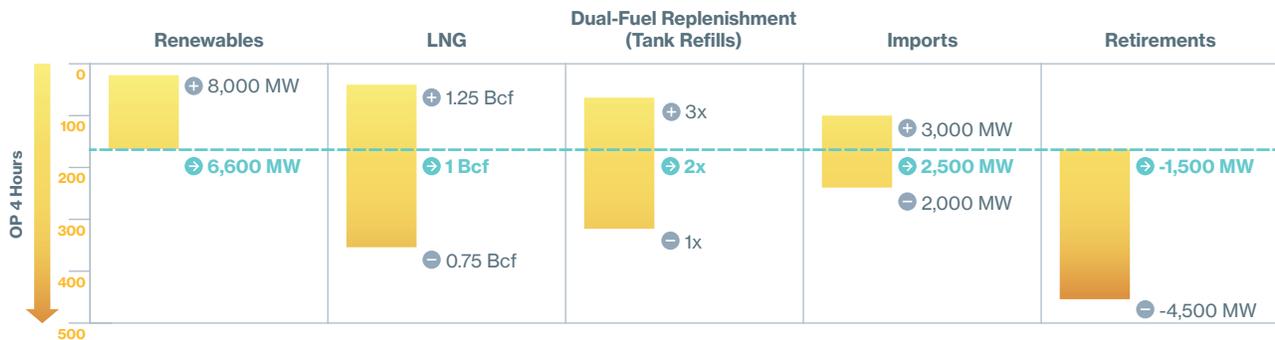
The single-variable scenarios with favorable inputs required from 0 to 7 hours of load shedding. The negative, single-variable scenarios, with the least favorable inputs, required load shedding ranging from 33 to 105 hours.

Figure 6 illustrates the range of OP 4 emergency-procedure hours resulting from each of the “plus” (favorable level) and “minus” (unfavorable level) single-variable cases. Figure 7 shows the range of OP 7 emergency-procedure hours for the single-variable cases.

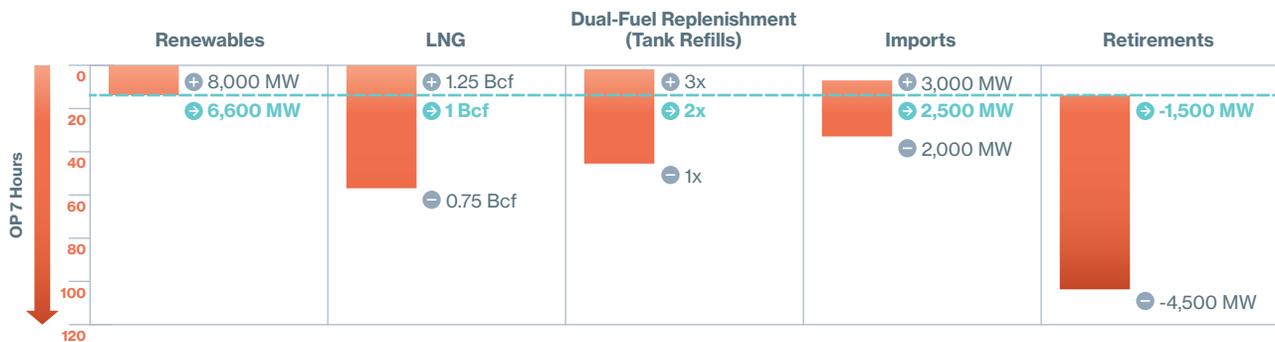
### Levels of Five Variables Are Key to Fuel-Security Risk

The single-variable cases explore the range of impacts of each of the five individual variables studied, as illustrated by these graphs. Each bar spans a variable's results from a high amount (⊕) through the reference case level (↔) and down to a low amount (⊖). Results in the first graph are measured in OP 4 emergency-action hours, which are an indicator of system stress and may involve public pleas for energy conservation. In the second graph, results are measured in OP 7 hours, which represent load shedding. Compared with the reference case, increased inputs lead to decreased risk – and vice versa (with the exception of retirements because more retirements lead to increased risk). No single variable eliminated all risk. Notably, decreases in each variable had proportionally greater negative effects, despite being of comparable value to the increases. The region's vulnerability to resource retirements and decreases in LNG availability is particularly evident.

**Figure 6: Ranges of OP 4 Hours in Single-Variable Cases**



**Figure 7: Ranges of OP 7 Hours in Single-Variable Cases**



■ Range of OP 4 Hours Spanning Plus and Minus Cases     
 ■ Range of OP 7 Hours Spanning Plus and Minus Cases     
 ⊕ High-Case Input Value      ⊖ Low-Case Input Value     
 - - - Reference Case Hours      ↔ Reference Case Input Values     
 Note: See Appendix A for more details.

## Renewable Resources

As shown in Table 4, no load shedding was required for the positive, single-variable scenario that increased renewables to 8,000 MW and imports to 3,500 MW (to represent an additional 1,000 MW of clean energy over a new transmission tie to a neighboring system).

The high-renewables scenario resulted in 29 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the scenario required 54.6 Bcf total LNG injections over the entire winter.

**Table 4: Assumptions and Results for the Scenario with More Renewables Compared with the Reference Case**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>More Renewables</b>	-1,500	1.00	2	3,500	8,000	29	24	6	2	0	0
<b>Reference Case</b>	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6

## LNG

The favorable single-variable scenario raised LNG injections to 1.25 Bcf/d, which equals the highest daily LNG injection seen at any one time in the last nine years. This scenario required no load shedding (refer to Table 5). The unfavorable LNG scenario posited a maximum injection of 0.75 Bcf/d. The lower LNG injections required 58 hours of load shedding over 10 days.

The high LNG scenario resulted in 32 days when at least 95% of the assumed maximum LNG injection of 1.25 Bcf/d was being used. Over the entire winter in this scenario, 71 Bcf of LNG was used in New England. The low LNG scenario resulted in 39 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was injected, and the region used 52.4 Bcf of LNG over the entire winter.

**Table 5: Assumptions and Results for the Scenarios with More and Less LNG Compared with the Reference Case**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>More LNG</b>	-1,500	1.25	2	2,500	6,600	32	40	9	6	0	0
<b>Reference Case</b>	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
<b>Less LNG</b>	-1,500	0.75	2	2,500	6,600	39	355	208	153	58	10

## Imports

Table 6 shows the results for the scenarios with more or less imports. The favorable single-variable scenario that raised imports to 3,000 MW, a level that was seen just 35% of the time during the winter period over the past five years, required 7 hours of load shedding over 4 days. The case that reduced imports to 2,000 MW, the level of imports seen on most days over the last five winters, required 33 hours of load shedding over 7 days.

The high-imports scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, with 60 Bcf/d imported for the winter. The low-imports scenario resulted in 36 days when at least 95% of the LNG was being used, up to the assumed maximum of 1 Bcf/d, and the region used 64.8 Bcf/d over the 90 days of winter.

**Table 6: Assumptions and Results for the Scenarios with More and Less Imports Compared with the Reference Case**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More Imports	-1,500	1.00	2	3,000	6,600	35	103	43	28	7	4
→ Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Imports	-1,500	1.00	2	2,000	6,600	36	239	120	87	33	7

## Dual-Fuel Replenishment

The scenario that increased the number of times dual-fuel generators' oil tanks were filled to three times during the winter – which would theoretically max out most generators' 30-day limit for running on oil – showed just one hour of load shedding on one day. The scenario that lowered the number of times oil tanks were filled to just once during the winter showed 46 hours of load shedding over 10 days. Refer to Table 7.

Both the high-oil-tank and low-oil-tank inventories scenarios resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Both the high-oil and low-oil inventories scenarios used 62.4 Bcf total LNG over the course of the winter.

**Table 7: Assumptions and Results for the Scenarios with More and Less Dual-Fuel Replenishment Compared with the Reference Case**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
More Dual-Fuel Replenishment	-1,500	1.00	3	2,500	6,600	35	69	26	13	1	1
→ Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Less Dual-Fuel Replenishment	-1,500	1.00	1	2,500	6,600	35	317	173	115	46	10

## Retirements

The unfavorable single-variable scenario that increased coal- and oil-fired power plant retirements to 4,500 MW had the worst outcomes among the single-variable cases: 105 hours of load shedding over 16 days, and 455 hours of all OP 4 actions as well as the depletion of 10-minute reserves during 258 hours of those OP 4 hours. The high-retirements scenario resulted in 35 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used, and the region used 62.4 Bcf/d over the winter. Table 8 summarizes the results for the high-retirements scenario.

**Table 8: Assumptions and Results for the Scenario with More Retirements Compared with the Reference Case**

						TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
More Retirements	-4,500	1.00	2	2,500	6,600	35	455	316	258	105	16

## Combination Scenarios

The four combination cases each altered several variables at one time to develop a combination of future resource mixes that reflect several possible future power systems. All these cases included higher levels of renewables, which could be considered a proxy for greater levels of EE that reduce consumer demand for power; adding renewables would reduce the need to turn to stored fuels.

All the combination cases also added 1,000 MW to imports to bring the total to 3,500 MW. By increasing imports by 1,000 MW, these scenarios account for the Massachusetts requirement for about 1,200 MW of clean energy, such as hydro or wind energy imported from Canada or New York over a new high-voltage transmission line. All the combination cases also assumed oil tanks were filled twice during the winter.

### Combination LNG Scenarios (High LNG and Low LNG with High Renewables/Higher Retirements)<sup>43</sup>

Two combination cases included high levels of renewables, at 8,000 MW, with imports at 3,500 MW, and higher levels of retirements, at 4,000 MW, with one case reducing LNG injections to 0.75 Bcf/d and the other increasing LNG injections to 1.25 Bcf/d. As shown in Table 9, the combination case with higher LNG injections showed no load shedding, while the combination case with low LNG injections resulted in 56 hours of load shedding over 12 days.

<sup>43</sup> The case names refer to the labels included on the detailed results matrix in Appendix A as well as the smaller tables included with the scenario results in the body of the report.

The high LNG combination scenario showed total LNG injections of 61.6 Bcf and resulted in 23 days when at least 95% of the assumed maximum of 1.25 Bcf/d LNG was being used. The low LNG injections scenario resulted in total LNG consumption of 46.3 Bcf over the winter and 35 days when at least 95% of the assumed maximum of 0.75 Bcf/d LNG was being used.

**Table 9: Assumptions and Results for the Combination LNG Scenarios Compared with the Reference Case**

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High LNG/ High Renewables/ Higher Retirements	-4,000	1.25	2	3,500	8,000	23	18	4	2	0	0
Low LNG/ High Renewables/ Higher Retirements	-4,000	0.75	2	3,500	8,000	35	358	200	154	56	12

### Combination Scenario with High Retirements (High Renewables/High Retirements)

The third combination scenario doubled the reference case retirements of non-gas-fired units to 3,000 MW. The scenario also set renewables and imports to 8,000 MW and 3,500 MW, respectively, and held the maximum LNG injections level with the reference case at 1 Bcf/d. With high retirements, renewables, and imports, the third combination case resulted in just 2 hours of load shedding on one day. This scenario also resulted in total LNG injections of 54.6 Bcf over the winter and 29 days when at least 95% of the assumed maximum of 1 Bcf/d LNG was being used. Table 10 shows these results.

**Table 10: Assumptions and Results for the Combination Scenario with High Retirements Compared with the Reference Case**

	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
High Renewables/ High Retirements	-3,000	1.00	2	3,500	8,000	29	84	25	17	2	1

## Combination Scenario with Maximum Renewables and Maximum Retirements (Max Renewables/Max Retirements, or Max)

The fourth combination scenario assumed that the region's entire fleet of coal- and oil-fired generators had retired, totaling 5,400 MW. The case also assumed that the region's fleet of renewables had grown to 9,500 MW, the maximum level used in the study. This scenario added about 900 MW to the PV forecast, bringing the total PV to 5,300 MW. The projected level of offshore wind was increased by another 400 MW above the 1,600 MW offshore wind requirements of the Massachusetts energy legislation, to 2,000 MW. This scenario also increased imports to 3,500 MW, incorporating 1,000 MW of clean energy imported from neighboring systems.

This scenario could be considered akin to the effects of implementing strict carbon reduction goals or using other regulations to significantly limit carbon emissions from power plants. Carbon-reduction initiatives would attract higher levels of renewables and drive more fossil-fuel-fired generators to retirement.

In the scenario, with high retirements and high renewables, 15 hours of load shedding over 6 days was needed, and 52.9 Bcf of LNG was required over the winter, resulting in 23 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. Refer to Table 11.

**Table 11: Assumptions and Results for the Combination Scenario with Maximum Retirements and Renewables Compared with the Reference Case**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
 Reference Case	-1,500	1.00	2	2,500	6,600	35	165	76	53	14	6
Max Renewables/Max Retirements (Max)	-5,400	1.00	2	3,500	9,500	23	206	94	64	15	6

## Outage Scenarios

Eight outage scenarios show the consequences of four possible high-impact events involving the outages of important energy facilities for an entire winter. Outages of shorter duration would also create significant system stress and could require the implementation of emergency actions. Each of the outages was modeled twice: on a system represented by the reference case (*Ref*) and on a system represented by the combination case that includes the maximum levels of retirements and renewables assumed in the study (*Max Renewables/Max Retirements [Max]*).

The winter-long outages of the following facilities were modeled:

- ▶ A compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and restricting fuel to about 7,000 MW of generation for the entire winter
- ▶ The loss of Millstone Nuclear Power Station in Connecticut, one of the region’s remaining two nuclear stations, eliminating 2,100 MW of baseload power
- ▶ The loss of the Canaport LNG import and regasification facility in New Brunswick, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems
- ▶ A disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d that can be injected by Distrigas into the Algonquin and Tennessee interstate gas pipeline systems and the local gas utility’s distribution system

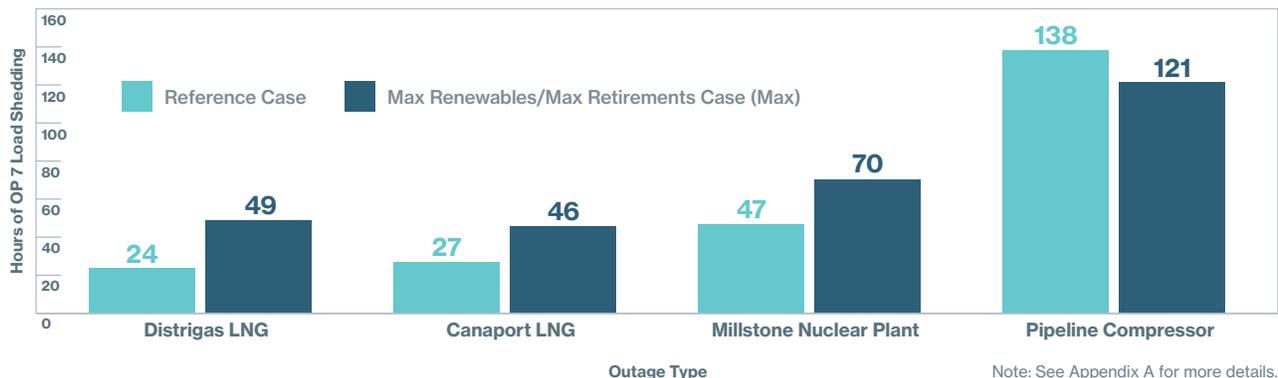
Figure 8 shows the projected hours of load shedding resulting from a season-long outage of a major fuel or energy source in the reference and *Max* cases.

Some variables in the reference and *Max* cases were adjusted to reflect the expected consequences of each outage. For example, the reference case assumes that 1 Bcf/d would be the maximum LNG injection available on any given day. But if a compressor station went out for the entire winter, natural gas prices would rise and LNG suppliers would be expected to ship more LNG to New England. Similarly, higher natural gas prices mean higher wholesale electricity prices in New England, so dual-fuel generators could be expected to fill their tanks more often to ensure they would have fuel to run when prices were high.

### High Levels of LNG, Oil, Imports, and Renewables Would Not Eliminate Load Shedding if a Major Energy Facility Goes Out

This graph shows the projected hours of load shedding (i.e., OP 7) that would result from the season-long loss of the Distrigas LNG terminal, Canaport LNG terminal, the Millstone nuclear plant, or an interstate pipeline compressor station. The study looked at the impacts of each of these outages in both the reference case and Max case, with the highest amount of renewables and retirements. It is worth noting that even the most aggressive increases in LNG, oil, and renewables would not prevent the need for load shedding, particularly during a pipeline compressor station outage. These winter-long outage scenarios also hint at the severe impact of a shorter-term outage, which would provide less time for the markets to mobilize other fuel or energy sources.

**Figure 8: Projected Hours of Load Shedding due to Season-Long Outage of a Major Fuel or Energy Source**  
(Reference Case Compared with the Max Scenario)



## Compressor Outage

As outlined above, the winter-long loss of a natural gas pipeline compressor station would likely spur higher imports of LNG and more frequent oil tank refills. Taking that into account, the maximum LNG injection assumed in both the reference and combination scenarios was increased from 1 Bcf/d to 1.5 Bcf/d, higher than the highest coincident injection of 1.25 Bcf/d seen on any one day in the region. These scenarios also assumed oil tanks were filled three times, rather than twice. Even with additional LNG and oil, the compressor station outage in the reference case (*Compressor Outage: Ref*) would have the highest number of load-shedding hours (apart from the unlikely worst-case scenario), at 138 hours over 17 days. On a power system represented by the scenario with the maximum level of retirements and renewables (*Compressor Outage: Max*), 121 load-shedding hours over 19 days would be needed. Table 12 shows the assumptions and results for this scenario.

Over 17 days, 138 hours of load shedding would equate to about eight hours per day, though given the variations in system conditions from day to day and hour to hour, such an even distribution of load shedding would be unlikely. Some days would have less than eight hours of load shedding; some would have more.

The compressor station outage in the reference case resulted in 127.8 Bcf of total LNG injections over the winter, while the outage in the combination scenario required 112.2 Bcf. Both are far higher than the highest level of LNG delivered to New England pipelines, which was 73 Bcf in winter 2010/2011. The reference case and combination cases resulted in 47 days and 41 days, respectively, when at least 95% of the assumed maximum daily LNG injection of 1.5 Bcf/d was being used.

As these results illustrate, a pipeline compressor outage would have a significant impact on New England's power system because of the region's limited network of pipelines; most or all the limited natural gas that could get into New England would go to gas utilities serving their heating customers.

**Table 12: Assumptions and Results for the Pipeline Compressor Outage Scenarios**

						TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>Compressor Outage: Ref</b>	-1,500	1.50	3	2,500	6,600	47	458	290	252	138	17
<b>Compressor Outage: Max</b>	-5,400	1.50	3	3,500	9,500	41	510	340	273	121	19

## Millstone Nuclear Outage

The winter-long outage of a nuclear power station was incorporated into the hourly dispatch employed by the study model, rather than represented as an input variable. The model assumed that Millstone, a 2,100 MW nuclear power plant, which would usually be among the first resources dispatched every day, would not be available for the entire winter. Without this baseload resource, more resources using other

fuels, including natural gas, oil, and LNG, would be needed more often, depleting their fuel sources. In the reference case, the nuclear outage (*Millstone Nuclear Outage: Ref*) would require 47 hours of load shedding over 10 days. Refer to Table 13.

In the nuclear outage case with maximum retirements and maximum renewables (*Millstone Nuclear Outage: Max*), more renewables would help when available, but the absence of all coal- and oil-fired generators coupled with the nuclear outage would mean virtually all the power plants with stored fuel in New England would be unavailable. The result would be 70 hours of load shedding over 12 days.

The Millstone reference case outage resulted in 72.9 Bcf total LNG injections over the winter – about the same as the most wintertime LNG deliveries seen to date – and 42 days when at least 95% of the assumed maximum daily LNG injection of 1 Bcf/d was being used. The nuclear combination case outage resulted in total LNG injections of 61.6 Bcf over the winter, and 36 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used.

**Table 13: Assumptions and Results for the Millstone Nuclear Outage Scenarios**

						TOTAL WINTER IMPACT					
	Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills)	Imports (MW)	Renewables (MW)	Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>Millstone Nuclear Outage: Ref</b>	-1,500	1.00	3	2,500	6,600	42	349	166	124	47	10
<b>Millstone Nuclear Outage: Max</b>	-5,400	1.00	3	3,500	9,500	36	389	243	193	70	12

### Distrigas LNG and Mystic 8 and 9 Outage

On a power system represented by the reference case, the outage of Distrigas, one of the region’s three LNG import facilities and the nearby Mystic 8 and 9 generating units fueled by that imported LNG, would cause 24 hours of load shedding over seven days (*Distrigas LNG Outage: Ref*), as shown in Table 14. If the outage occurred on a system with maximum retirements and maximum renewables, twice as many load shedding hours would be required, at 49 hours over 11 days (*Distrigas LNG Outage: Max*).

The Distrigas outage in the reference scenario resulted in 50.9 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. The *Distrigas LNG Outage: Max* scenario resulted in total LNG injections of 43.8 Bcf over the winter, and 34 days when at least 95% of the assumed maximum LNG injection of 1 Bcf/d was being used. While this scenario assumed that the Distrigas LNG import facility would be out of service during the entire winter, maximum LNG injections were not reduced below 1 Bcf/d because it was assumed the region’s other two LNG facilities would increase their imports.

**Table 14: Assumptions and Results for the Distrigas and Mystic 8 and 9 Outage Scenarios**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>Distrigas LNG Outage: Ref</b>	-1,500	1.00	3	2,500	6,600	41	276	114	87	24	7
<b>Distrigas LNG Outage: Max</b>	-5,400	1.00	3	3,500	9,500	34	346	181	142	49	11

### Canaport LNG Terminal Outage

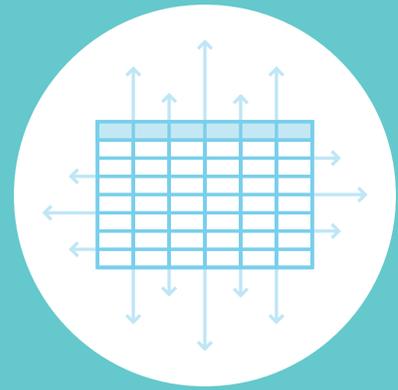
The season-long outage of the large Canaport LNG import facility in Canada would reduce the LNG available to inject into New England’s pipeline system. The study reflects this by reducing LNG injections to 0.65 Bcf/d, the lowest level assumed in any scenario. In the reference case, the outage would cause load to be shed 27 hours over nine days (*Canaport LNG Outage: Ref*). In the scenario with maximum retirements and maximum renewables, the outage would require 46 hours of load shedding over 11 days (*Canaport LNG Outage: Max*). Refer to Table 15.

The Canaport LNG import facility outage in the reference scenario resulted in 48.1 Bcf total LNG injections over the winter, and 41 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used. The *Canaport LNG Outage: Max* resulted in 41.4 Bcf total LNG injections over the winter and 35 days when at least 95% of the assumed maximum LNG injection of 0.65 Bcf/d was being used.

**Table 15: Assumptions and Results for the Canaport LNG Outage Scenarios**

	 Retirements (MW)	 LNG Cap (Bcf/Day)	 Dual-Fuel (Oil Tank Fills)	 Imports (MW)	 Renewables (MW)	TOTAL WINTER IMPACT					
						Days of LNG at ≥95% Assumed Cap	All OP 4 Hours	OP 4 Actions 6-11	Hrs. of 10-Min. Reserve Depletion	Hrs. of Load Shedding (OP 7)	Days with Load Shedding (OP 7)
<b>Canaport LNG Outage: Ref</b>	-1,500	0.65	3	2,500	6,600	41	270	129	90	27	9
<b>Canaport LNG Outage: Max</b>	-5,400	0.65	3	3,500	9,500	35	354	187	134	46	11

# Key Findings



## Key findings from the report include:

- ▶ **All four outage scenarios** involving the winter-long loss of key energy facilities produced the most severe outcomes, illustrating the region's vulnerability to these sources. Each outage of a natural gas pipeline compressor station, a nuclear station, or one of the region's LNG import facilities resulted in hundreds of hours of operating procedures and emergency actions and between two dozen and more than 100 hours of load shedding. The loss of a compressor station was particularly problematic, given the resulting reduction in natural gas supply in New England. The local gas utilities would fully use their firm capacity rights on other pipelines and secure priority rights to the region's LNG facilities for many more hours. This would further reduce the natural gas available to power plants, with the results showing more than 120 hours of load shedding spread across 19 days.
- ▶ **Two combination cases (*High LNG/High Renewables/Higher Retirements and High Renewables/High Retirements*)** showed that higher levels of retirements of oil- and coal-fired power plants could be addressed with higher levels of LNG, imports, and renewables, resulting in fewer hours of emergency actions, less need to deplete operating reserves, and very limited exposure to load shedding. These cases' inputs fall in the range between the reference case and the scenario with maximum retirements and maximum renewables, indicating that the power system can be expected to remain extremely vulnerable to the outages of any of the region's key energy suppliers.
- ▶ **A combination case (*Low LNG/High Renewables/Higher Retirements*)** with a high level of retirements of non-gas-fired generators coupled with lower LNG injections required frequent emergency actions and multiple hours of load shedding, despite higher levels of imports and renewables.
- ▶ **The combination case (*Max Renewables/Max Retirements*)** with maximum retirements and maximum renewables illustrated the impacts of retiring every at-risk coal- and oil-fired generator in the region and developing the highest level of renewable resources. With moderate levels of LNG, imports, and oil tank inventories, more than 200 hours of emergency actions and more than a dozen hours of load shedding over six days were required to maintain system balance. The outage scenarios based on this combination case demonstrated that the loss of a key energy facility would exacerbate the use of emergency procedures.

► **The single-variable cases** that raised or lowered just one variable showed the following:

- **The retirements of oil- and coal-fired power plants** have the greatest impact among the five variables on increasing the region’s fuel-security risk, as measured by the frequency and duration of energy shortfalls requiring emergency actions. The scenarios that raised the level of retirements saw a seven-fold increase in OP 7 hours over the reference case. Other negative variables increased load shedding to no more than four times the reference case level.
- **Lower LNG injections** have the next-greatest impact on increasing the region’s fuel-security risk, increasing load shedding to nearly 60 hours compared with 14 hours in the reference case. **Conversely, higher LNG injections** have a significant impact on reducing the region’s fuel-security risk – the higher LNG case had no load shedding and far fewer hours of emergency actions.
- **Increased oil inventories at dual-fuel generators** also significantly improve fuel security. The single-variable scenario that increased the number of times dual-fuel power plants could replenish their oil inventory showed relatively lower levels of system stress, including just one hour of load shedding.
- **Large amounts of renewable resources combined with additional imports** lowered the fuel-security risk compared with the reference case, with no load shedding and a greatly reduced need for emergency actions.

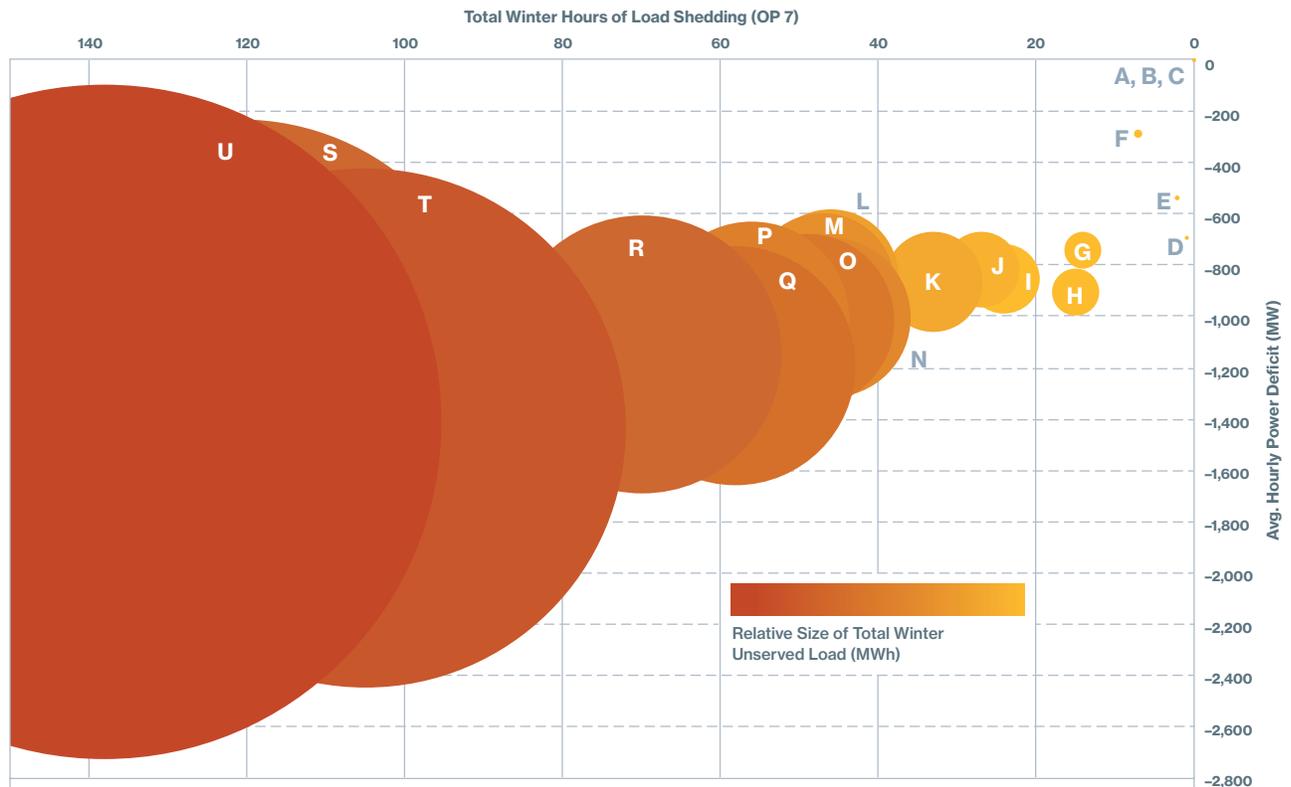
► **The two boundary cases that moved all variables in either the most favorable or least favorable direction** showed the most positive or negative results, as would be expected. But each of the boundary scenarios would require all five variables to evolve in the same direction, which is unlikely.

Figure 9 reflects the magnitude of load shedding (i.e., OP 7) in all but the high and low boundary scenarios, with the bubble size depicting the total projected megawatt-hours (MWh) of unserved load. One megawatt-hour is the amount of energy produced by 1 MW over one hour. A power resource of 500 MW capacity, for example, will provide 1,000 MWh of energy if it operates at this capacity for two hours. In New England, 1 MWh can serve the equivalent of approximately 860 homes for one hour, on average. This study assumed New England would have sufficient resource *capacity* (megawatts) to meet future demand in winter 2024/2025, and instead focused on the ability of that capacity to generate *energy* over time (megawatt-hours). Megawatt-hours of energy shortfalls – or unserved load – demonstrate how fuel availability can ultimately determine a resource’s actual output over the course of an entire winter, regardless of its capacity.

## The Greatest Risks Come from Major Outages, More Retirements, and Lower LNG and Oil Supplies

This chart reflects the magnitude of load shedding (i.e., OP 7) in each of the scenarios. (The high and low boundary cases were omitted.) The bubble size represents the total megawatt-hours of load shedding for the winter, illustrating the region's vulnerability to outages of major energy facilities, increases in retirements, and drops in LNG or oil supplies.

Figure 9: Magnitude of Load Shedding in Modeled Cases



### Cases Ordered by Total Winter Unserved Load (MWh), Least to Most:

Case	MWh	Case	MWh	Case	MWh
A) High LNG/High Renewables/ Higher Retirements ☺	0	H) Max Renewables/ Max Retirements (Max) ☺	13,609	O) Distrigas LNG Outage: Max ☹	49,805
B) More Renewables ☺	0	I) Distrigas LNG Outage: Ref ☹	20,496	P) Low LNG/High Renewables/ Higher Retirements ☺	56,518
C) More LNG ☺	0	J) Canaport LNG Outage: Ref ☹	22,026	Q) Less LNG ☺	69,179
D) More Dual-Fuel Replenishment ☺	696	K) Less Imports ☺	28,608	R) Millstone Nuclear Outage: Max ☹	80,312
E) High Renewables/ High Retirements ☺	1,070	L) Canaport LNG Outage: Max ☹	38,819	S) Compressor Outage: Max ☹	149,574
F) More Imports ☺	2,031	M) Millstone Nuclear Outage: Ref ☹	41,080	T) More Retirements ☺	150,297
G) Reference Case ☺	10,397	N) Less Dual-Fuel Replenishment ☺	46,232	U) Compressor Outage: Ref ☹	194,705

☺ Single-Variable Cases

☺ Combination Cases

☹ Outage Cases

Note: See Appendix A for more details.

# Conclusions



For New England, the foremost risk to current and future power system reliability revolves around fuel security – the ability of power plants to get the fuel they need to run, when they need it.

This operational fuel-security assessment has quantified the level of risk in a wide range of possible future resource combinations and provides information the region can use to consider approaches to ensuring power system reliability. The diversity of scenarios was designed to help ISO New England and its stakeholders better understand how well these future power system profiles, or other profiles that fall between them, could support power system reliability throughout an entire winter.

The study results indicate the risk of future energy shortfalls is greater than the risk today. All but one of the 23 scenarios show that the regional power system could frequently experience some degree of system stress, requiring system operators to employ emergency procedures. All but four scenarios show that some level of load shedding would be needed to maintain system balance. This indicates that the region is currently maintaining a delicate balance that could easily be disrupted if any of the five key variables – retirements of coal- and oil-fired generators, LNG injection levels, the availability of oil as well as the permitted ability to burn oil, electricity imports, and the development of renewable resources – trend in a negative direction at an accelerated rate.

This fuel-security analysis also illustrates the acute vulnerability of New England's power system to the loss of any one of several key energy facilities. The region is particularly vulnerable to an outage at a natural gas pipeline compressor station.

## Outages

The regional dependency on several key facilities is a particular concern highlighted by this study. An extended outage at any one of these key facilities – a natural gas pipeline compressor station, the Distrigas LNG import facility in Massachusetts and the Mystic 8 and 9 generators it fuels, the Canaport LNG import facility in Canada, or the Millstone nuclear power plant – would result in frequent energy shortages that would require frequent and long periods of rolling blackouts.<sup>44</sup> While outages of shorter duration were not studied, the importance of these facilities to system reliability is highlighted by the results of this fuel-security study. An outage at any of these facilities, regardless of duration, would likely create significant system stress.

<sup>44</sup>. Potomac Economics 2016 *Assessment of the ISO New England Electricity Markets*, report of the ISO New England external market monitor (June 2017), p.22, <https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf>. "In the Baseline scenarios shown in Figure 7, LNG capacity would become pivotal for meeting generators' demand in 2023/24, even if the oil storage is fully utilized."

The reliability impact of any one of these outages cannot be eliminated, even on a system with more LNG, oil inventory, and imports, the study shows. Each outage scenario would require load shedding that could affect hundreds of thousands of average New England homes at a time.

A compressor station outage on a major natural gas pipeline would have the most severe impact on power system reliability, requiring the most frequent and extensive load shedding of all the scenarios, aside from the unlikely negative boundary scenario. Frequent load shedding would be required even in a scenario with the likely increase in imports of LNG and electricity, as well as greater use of oil inventories by dual-fuel power plants and very high levels of renewable resources.

The ISO's ability to address this high-impact scenario is limited to designing operational procedures to ensure that if such a compressor station or pipeline outage occurs, system stability can be maintained and cascading outages are prevented. The impact of such an outage can be mitigated through the use of increased LNG and imported electricity, as well as greater renewable resources and dual-fuel capacity with enhanced strategies for replenishing oil tank inventories.

## Stored Fuels: Imported LNG, Electricity Imports, and Dual-Fuel Capability

The study illustrates that over the next several decades, New England's power system will largely depend on the availability of two key elements: sufficient injections of LNG and electricity imports from neighboring regions. However, the availability of LNG and imports may be subject to some forces that are outside the purview of ISO New England and New England's policymakers.

Additional dual-fuel capability, which will increase the inventory of stored oil available to generate electricity when other fuels are not available in sufficient quantities, would also provide a key contribution to power system reliability. However, state emissions requirements are tightening, which will limit the amount of time some generators can run on oil, and obtaining permits to construct new dual-fuel generators is becoming more difficult.

LNG injections from import terminals in the east and Canada have provided important supplements to pipeline gas and have helped support New England's power system reliability, but as demand for natural gas for heating rises and pipeline capacity remains the same, more local gas utilities are contracting for LNG to serve their customers. Further, as natural gas fields in Atlantic Canada are depleted, the Maritimes' demand for natural gas from pipelines and LNG import facilities is expected to rise. In the future, less LNG may be available for power plants in New England. But at the same time, the continuing retirements of oil- and coal-fired power plants, which use fuel stored on site, will increase New England's reliance on imported LNG.

Robust levels of imported electricity from neighboring power systems are essential to continued power system reliability. However, imports also present a degree of uncertainty and risk. Each scenario assumes a level of imports at least twice the amount obligated through the Forward Capacity Market.<sup>45</sup> In other words, half the imports assumed in the study may not be available if the neighboring area where they are located needs them. This is important because Québec, New York, and New Brunswick all experience winter weather at the same time as New England. The question is whether New England's neighbors will have enough electricity to serve their own customers and supply New England with all the electricity

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<sup>45</sup> Resources that clear in the annual Forward Capacity Market auction administered by ISO New England take on an obligation (called a capacity supply obligation, or CSO) to be available in the relevant capacity commitment period. In return, they receive a monthly payment based on the auction clearing price and the number of megawatts they promised to make available.

assumed in the scenarios. Also, New York and New Brunswick, as well as New England, all depend on imports from Québec. A power system contingency in Québec can deplete its exports and have a domino effect on its neighbors.<sup>46</sup>

Further, as New York's power system evolves away from oil-fired and nuclear plants with on-site fuel, and toward increased dependence on natural gas and renewables, the extent of the New York system's ability to support electricity exports to New England is unclear. Also unclear is whether this trend will reduce the availability of pipeline gas supplied to New England.

With the increasing retirements of generators with stored fuels (nuclear, coal, and oil), the region's reliance on imported fuels and electricity is likely to grow. Greater levels of dual-fuel capability, which would enable natural-gas-fired generators to turn to oil stored onsite when they can't get gas, helps system reliability.

## Logistics

Some resource mixes pose less fuel-security risk than others, but all scenarios are subject to the unquantifiable uncertainties of fuel-delivery logistics, weather, and events that unfold on the power grid more randomly than can be represented in a study of this type.

Fuel-delivery logistics are a factor in fuel-security risk. As winter progresses, the cumulative use of oil and LNG depletes power plants' inventories, requiring replenishment and heightening the importance of timely fuel deliveries. Refilling oil and LNG tanks at some point over the course of a 90-day winter is not the problem. But when winter storms and cold snaps follow on each other in quick succession, refilling fuel tanks quickly is of paramount importance. Timely replenishment can be challenging, however, because of the difficulty in predicting far enough in advance how much LNG or oil will be needed to ensure trucks and LNG tankers will arrive when needed.

The vagaries of weather, combined with restrictions on how often power plants can run on oil, compound the uncertainties of fuel-delivery logistics. Most power plants in New England are limited to operating on oil no more than 30 days per year. A cold December with limited availability of natural gas could cause a generator to not only deplete its fuel inventory but also reduce the days remaining that it can run on oil – with two months of winter left to go.

The study results highlight significant logistical questions that may have an impact on fuel adequacy for generators. For example, will ocean-going tankers of LNG, a global commodity, arrive in the northeast when needed? Will winter storms prevent oil trucks from delivering fuel to power plants? Will tanker trucks be unavailable because they are delivering oil first to heating customers? Will New England weather deliver a one-two punch of extreme cold followed by a severe storm, leaving more generators with depleted inventories and not enough time to get their tanks refilled, as happened in 2013?<sup>47</sup> And will neighboring power systems deliver the high levels of imports most of these scenarios count on, at a time when their own winter demand is peaking?

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46. Jan Ellen Spiegel, "Canadian fires cause close call for New England power supply," CT Mirror (August 8, 2013), <https://ctmirror.org/2013/08/08/canadian-fires-cause-close-call-new-england-power-supply/>.

47. ISO New England, "New England grid operated reliably through 2012/2013 winter despite resource performance challenges" (ISO Newswire, March 27, 2013), <http://isonewswire.com/updates/2013/3/27/new-england-grid-operated-reliably-through-20122013-winter-d.html>.

ISO New England, "Winter Operations Summary: January–February 2013," draft paper (February 28, 2013), [https://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/strategic\\_planning\\_discussion/materials/winter\\_operations\\_summary\\_2013\\_feb\\_27\\_draft\\_for\\_discussion.pdf](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_27_draft_for_discussion.pdf).

## Risk Trending in a Negative Direction

Current trends are pushing the New England power system on a path toward greater fuel-security risks. These trends include the increasing retirements of power plants with fuel stored onsite (nuclear, coal and oil); the growth in power plants dependent on natural gas, a fuel that's delivered just in time; growing demand for natural gas from local gas utilities in both New England and the Maritimes, which will likely leave less for power plants; and an increase in renewable resources with variable production.

This fuel-security analysis was conducted to quantify the potential operational impacts of these trends. The wide range of 23 hypothetical scenarios was designed to illustrate the potential outcomes from a variety of future power systems made up of different resource combinations, including more favorable as well as less favorable levels of each variable. The study incorporated expected levels of energy-efficiency measures into its demand forecast and included significant development of behind-the-meter solar, offshore wind, and additional imports.

Only four of the scenarios – including the positive boundary scenario, which is highly unlikely to materialize – had no load shedding and few emergency actions. And the study results clearly show that New England remains extremely vulnerable to the loss of any of the region's key energy facilities.

The reference case, which represents a future power system that could be expected to develop, required hundreds of hours of emergency actions and the depletion of reserves and more than a dozen hours of load shedding. These risks could be offset by additional LNG imports or more renewable energy. However, the addition of large quantities of low-cost renewable resources is expected to lower wholesale energy prices and drive additional non-gas-fired generators to retirement, thus exacerbating fuel-security risks.

On balance, the analysis revealed that fuel-security risks are present in the vast majority of cases, even in scenarios with higher LNG, renewables, and imports.

The wide range of scenarios provides not just clear illustrations of what would happen if the power system evolved as outlined in each scenario, but also allows for conclusions about the outcomes of intermediate levels of each variable.

## More Renewables Help, but Don't Eliminate the Risk

Renewable resources can mitigate the region's fuel-security risk, and the study includes scenarios that incorporate all, and in some cases more than, the renewable resources that could result from existing or future clean energy initiatives of several New England states.

The growth of renewable resources, with their low operating costs, is likely to drive greater retirements of more costly, aging coal- and oil-fired power plants. Even when the retirements of these generators occurs in tandem with robust growth of renewable resources, the region's dependence on higher imports of LNG to counteract the loss of stored fuels is not erased.

Another factor is the timing of winter peak demand, which occurs after the sun has set. Solar arrays can help reduce consumption of oil and natural gas for power generation on sunny winter days, preserving more oil and gas to help meet peak demand. But solar PV itself does not help meet the daily winter peak in demand.

Energy from wind farms isn't always available when needed, though offshore wind tends to blow more steadily than onshore wind. Further, developing more onshore wind facilities in northern New England and importing more clean energy from neighboring systems will require significant investment in new transmission infrastructure.

Energy storage can help even out intermittent output from wind and solar resources and support system reliability, but cost-effective, utility-scale advanced energy storage is still being developed.

## More Positive Outcomes

A resource mix with higher levels of LNG, imports, and renewables shows less system stress than the reference case. These scenarios, while based on resources dependent on uncontrollable factors – the global LNG market, the coincident winter demands of regions exporting power to New England, and weather – result in fewer hours of emergency actions, depletion of reserves, and load shedding. To achieve these levels of LNG, imports, and renewables, firm contracts for LNG delivery, assurances that electricity imports will be delivered in winter, and aggressive development of renewables, including expansion of the transmission system to import more clean energy from neighboring systems, would be required.

# Next Steps



The ISO will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018.

A key question to be addressed will be the level of fuel-security risk that the ISO, the region, and its policymakers and regulators are willing to tolerate. As the system operator mandated to maintain a reliable power system, the ISO must conduct its own assessment of the level of risk to reliable operations. A primary consideration will be ISO New England's responsibility, as a regional reliability coordinator, to operate the region's power system in a way that maintains the reliability of not only the region but also the entire Eastern Interconnection.

Discussions about possible solutions to the region's fuel-security risk are also expected to commence in 2018. The ISO will work with stakeholders to determine whether further operational or market design measures will be needed to address the fuel-security risks already confronting the New England power system and that may accelerate in the coming years.

Using the new model developed for this study, the ISO plans to conduct periodic operational assessments to re-evaluate the level of fuel-security risk presented by the resources available at the time. The ISO could also conduct additional analysis based on stakeholder feedback on the study results.

		TOTAL WINTER IMPACT															
		INPUTS					OP 4 Actions		Depletion of 10-Minute Reserves <sup>1</sup>			OP 7 Action: Load Shedding					
		Retirements (MW)	LNG Cap (Bcf/Day)	Dual-Fuel (Oil Tank Fills) <sup>2</sup>	Imports (MW)	Renewables (MW) <sup>3</sup>	All OP 4 Actions	Actions 6-11	Hours	Avg. Hourly Power Deficit (MW) <sup>4</sup>	Hours	Avg. Hourly Power Deficit (MW) <sup>4</sup>	Load at Risk (MWh) <sup>5</sup>	Hours	Avg. Hourly Power Deficit (MW) <sup>4</sup>	Unserviced Load (MWh) <sup>5</sup>	Days with Load Shedding
<b>S Reference Case (i.e., Current Trends) and Single-Variable Cases</b>																	
ROW																	
1	+ High Boundary	-1,500	1.25	3	3,500	8,000	0	0	0	0	0	0	0	0	0	0	0
2	More Renewables	-1,500	1.00	2	3,500	8,000	24	6	408	2	765	1,530	0	0	0	0	
3	More LNG	-1,500	1.25	2	2,500	6,600	40	9	440	6	545	3,272	0	0	0	0	
4	More Dual-Fuel Replenishment	-1,500	1.00	3	2,500	6,600	69	26	319	13	609	7,913	1	696	696	1	
5	More Imports	-1,500	1.00	2	3,000	6,600	103	43	404	28	816	22,859	7	290	2,031	4	
6	→ Reference Case (Ref)	-1,500	1.00	2	2,500	6,600	165	76	419	53	980	51,963	14	743	10,397	6	
7	Less Imports	-1,500	1.00	2	2,000	6,600	239	120	427	87	1,039	90,395	33	867	28,608	7	
8	Less Dual-Fuel Replenishment	-1,500	1.00	1	2,500	6,600	317	173	410	115	1,079	124,045	46	1,005	46,232	10	
9	Less LNG	-1,500	0.75	2	2,500	6,600	355	208	430	153	1,072	164,065	58	1,193	69,179	10	
10	More Retirements	-4,500	1.00	2	2,500	6,600	455	316	454	258	1,078	278,135	105	1,431	150,297	16	
11	- Low Boundary	-4,500	0.75	1	2,000	6,600	811	692	480	642	1,394	895,145	475	2,080	987,872	31	
<b>C Combination Cases</b>																	
12	High Renewables/High Retirements	-3,000	1.00	2	3,500	8,000	84	25	373	17	760	12,918	2	535	1,070	1	
13	High LNG/High Renewables/Higher Retirements	-4,000	1.25	2	3,500	8,000	18	4	405	2	500	1,000	0	0	0	0	
14	Low LNG/High Renewables/Higher Retirements	-4,000	0.75	2	3,500	8,000	358	200	435	154	1,030	158,552	56	1,009	56,518	12	
15	Max Renewables/Max Retirements (Max)	-5,400	1.00	2	3,500	9,500	206	94	408	64	934	59,790	15	907	13,609	6	
<b>O Outage Cases (Modeled on Ref and Max Cases; Assumed More Dual-Fuel Tank Fills)</b>																	
16	Distrigas LNG Outage: Ref <sup>6</sup>	-1,500	1.00	3	2,500	6,600	276	114	440	87	961	83,628	24	854	20,496	7	
17	Distrigas LNG Outage: Max <sup>6</sup>	-5,400	1.00	3	3,500	9,500	346	181	442	142	971	137,814	49	1,016	49,805	11	
18	Canaport LNG Outage: Ref <sup>7</sup>	-1,500	0.65	3	2,500	6,600	270	129	421	90	944	84,973	27	816	22,026	9	
19	Canaport LNG Outage: Max <sup>7</sup>	-5,400	0.65	3	3,500	9,500	354	187	424	134	998	133,779	46	844	38,819	11	
20	Millstone Nuclear Outage: Ref <sup>8</sup>	-1,500	1.00	3	2,500	6,600	349	166	433	124	1,015	125,852	47	874	41,080	10	
21	Millstone Nuclear Outage: Max <sup>8</sup>	-5,400	1.00	3	3,500	9,500	389	243	450	193	1,012	195,358	70	1,147	80,312	12	
22	Compressor Outage: Ref <sup>9</sup>	-1,500	1.50	3	2,500	6,600	458	290	468	252	1,231	310,163	138	1,411	194,705	17	
23	Compressor Outage: Max <sup>9</sup>	-5,400	1.50	3	3,500	9,500	510	340	448	273	1,107	302,258	121	1,236	149,574	19	

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 Reference Case

- Once reserves are depleted, any resource loss or transmission line trip that cuts imports would trigger load shedding.
- Count assumed tanks were filled before winter, plus refilled during winter. For example, "2x" counted the initial full tank, plus one refill.
- Cases with increased renewables also included increased imports to reflect expected additions of clean energy imports from Canada or New York.
- On average, one megawatt (MW) of electricity can serve about 860 homes in New England, which has about 7.1 million retail customers, encompassing not just residential customers but also commercial and industrial.
- A megawatt-hour (MWh) of electricity can serve about 860 homes for one hour in New England, on average.

- Case assumed a disruption to the Distrigas LNG import facility in Massachusetts, eliminating all the natural gas that can fuel the nearby, 1,700 MW Mystic 8 and 9 gas-fired generators, as well as 0.435 Bcf/d the LNG facility can inject into the Algonquin and Tennessee interstate gas pipeline systems (0.3 Bcf/d) and the local gas utility's distribution system (0.135 Bcf/d).
- Case assumes the loss of Canaport, the major LNG import facility in New Brunswick, Canada, eliminating as much as 1.2 Bcf/d that could be injected into the New England and Maritimes pipeline systems.
- Case assumes the loss of Millstone, one of the region's remaining two nuclear power plants, eliminating 2,100 MW of baseload power.
- Case assumes the loss of a compressor station on a major natural gas pipeline, eliminating 1.2 Bcf/d and cutting off fuel for the entire winter to generators with a combined capacity of about 7,000 MW.