REVIEW OF ISO-NE OPERATIONAL FUEL SECURITY ANALYSIS

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To: Clients and Colleagues

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Earlier this month ISO-New England (ISO-NE) released a report (Operational Fuel-Security Analysis) detailing the findings of a fuel-security analysis that was initiated to assess concerns with the region's increasing reliance on natural gas-fired electricity. This dependence is set to increase with the retirement of oil, coal, and nuclear power plants. Increased reliance on natural gas, with limited incremental development of the region's natural gas pipeline capacity is projected to increase fuel security risks for New England.

The report identified fuel security, in particular the availability of natural gas during the winter peak periods, as the region's greatest risk to power system reliability. The report makes clear that this is a very real risk for New England. However, we believe that the static nature of assumptions where market responses aren't fully considered, and the specification and selection of scenarios has caused the study to overstate these risks. The report indicates one goal is to improve the region's understanding of these risks and to inform subsequent discussions. This memo seeks to contribute to that discussion.

Fuel security is the ability of power plants to get the fuel they need, when they need it. In recent winters, ISO-NE operators have had to deal with the challenges of fuel security. The report identified five key fuel variables that will affect the magnitude of these fuel security risks.

These variables are first discussed, then the results of ISO-NE's analysis, followed by commentary on issues that may cause the analysis to overstate these risks or the likely incidence of the reliability events (e.g., load shedding and other less severe emergency actions such as public requests for energy conservation) identified in the report.

ISO-NE Identified Fuel Variables

The first variable is the retirement of coal, oil, and nuclear power plants. ISO-NE noted that by June 2021, 4,600 MW of non-natural gas-fired generation will have retired, representing more than 10% of the region's total generating capacity including the Vermont Yankee nuclear generating station (620 MW) and the Pilgrim nuclear generating station (690 MW). In recent winters when the supply of natural gas for New England's generation fleet has been limited, these resources have supplied a significant portion of the grid's energy. (See Figure 1 below, which contrasts two days this winter.) Retirement of these facilities increases the region's reliance on natural gas and heightens natural gas constraints, which in turn increases fuel security risks.

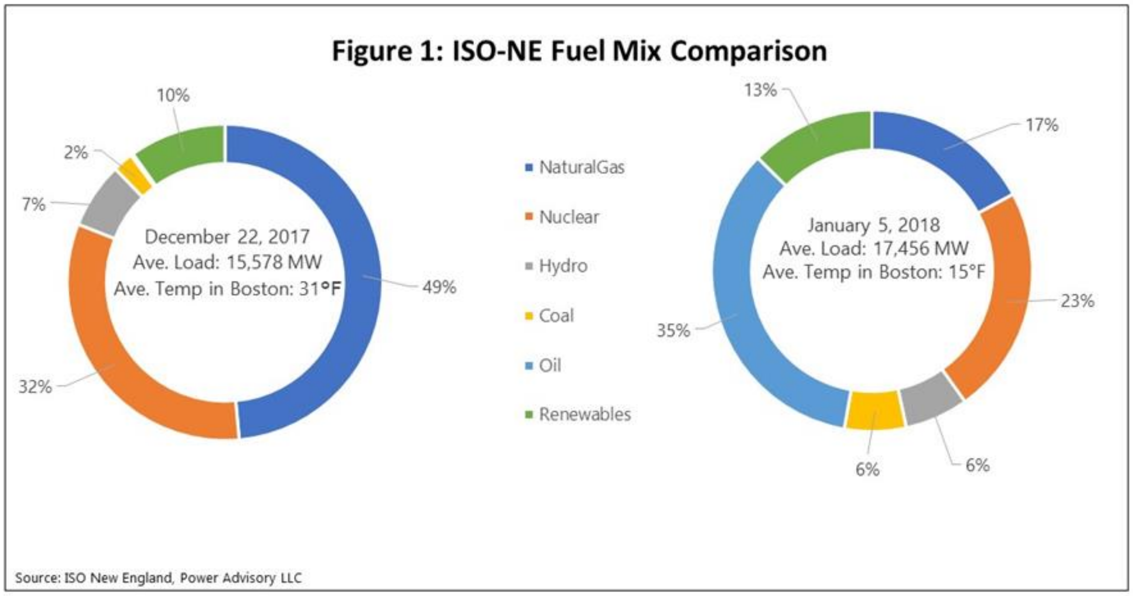

Figure 1: ISO-NE Fuel Mix Comparison

Source: ISO New England, Power Advisory LLC

The second fuel variable identified in the report is the availability of LNG. There are two primary LNG facilities that serve New England natural gas-fired generators: (1) the Distrigas facility in Everett, Massachusetts, which has a storage capability of 3.4 Bcf and vaporization capability of .7 Bcf/day and is owned and operated by Engie;[1,2] and (2) the Canaport LNG terminal in Saint John, New Brunswick, which has a storage capability of 10 Bcf and vaporization capability of .7 Bcf/day and is owned by Repsol and Irving Oil.[3] There is also two offshore LNG injection facilities: (1) the Northeast Gateway facility, which can inject .4 Bcf/day, but is rarely used; and (2) Neptune, which also can inject .4 Bcf/day, but has not operated since it achieved commercial operation.

The Distrigas and Canaport LNG terminals serve natural gas-fired generators in New England under a range of supply arrangements, but typically provide what is essentially a peaking supply. With LNG a global commodity, New England buyers must compete with buyers in distant markets. Given pipeline constraints into New England, during peak winter periods prices in New England are able to attract LNG supplies, but the short duration of these price events and limited storage capabilities of the LNG terminals do not ensure a sustained supply. Therefore, most cargoes of LNG need to be contracted and scheduled before winter begins. With the majority sourced from Trinidad and Tobago, once contracted the LNG won't arrive for at least five days. Delays from winter storms pose risks. ISO-NE noted: "Cold snaps can result in a sudden drawdown of stored LNG, and the rapid depletion of LNG

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[1] Mystic units 8 and 9 are directly connected with the Everett LNG terminal, which supplies their natural gas requirements.

[2] In its report ISO-NE indicates that the Distrigas project has a maximum injection of 0.435 Bcf/d into the interstate pipeline system and the local gas utility system". The Distrigas project has an additional .3 Bcf/day interconnection with Mystic station, such that the full vaporization capability of the Distrigas project can be utilized and a significant portion is dedicated to power generation.

[3] The Canaport LNG terminal is connected to the New Brunswick Pipeline and then the Maritimes & Northeast Pipeline, which in turn can deliver natural gas into Maine and southern New England markets.

combined with the region's limited storage facilities can challenge the region's fuel-supply chain, particularly if outages increase the need for LNG." (p. 16)

The third fuel variable is the supply of and maintenance of oil inventories at oil-fired and dual-fuel generation facilities. ISO-NE notes that with the retirement of oil-fired generating units, the infrastructure – barges and tanker trucks - to supply these facilities has withered. During a cold snap, winter storms can prevent tanker trucks from making deliveries, and federal restrictions on the number of hours drivers can drive can delay deliveries. These logistical issues pose the greatest risk to dual-fuel facilities given that they generally have the most limited on-site fuel storage capability. The operation of these facilities on oil is also constrained by air permits, which limit the number of hours of operation on oil. This became an issue in New England's recent cold snap. Given delays in fuel deliveries from winter storms and with some generators nearing emissions limits, ISO-NE took steps to conserve fuel by "posturing" units. Specifically, ISO-NE operated some facilities "out-of-merit" so that more economical generating units that had operating constraints would be available to operate later in the day or week. Recent regulations by the Massachusetts Department of Environmental Protection, which are being challenged in court, would ratchet down the operation of Massachusetts fossil units over time.

A fourth variable is the increasing penetration of renewable energy resources in New England. While renewables can help accommodate some of the loss in generation from coal, oil, and nuclear facilities, renewables are also contributing to the retirement of these plants by reducing the margins available in the energy market. With the renewable resources that are experiencing the fastest growth (i.e., solar and wind) having variable output, ISO-NE notes that they do not provide the same reliable supply offered by oil, coal, and nuclear units. Nonetheless, with renewable energy resources typically displacing natural gas-fired generation they are able to reduce electricity sector natural gas demand and the resulting natural gas constraints.

We believe that ISO-NE has significantly understated the likely contribution of renewables in two key areas: (1) no incremental on-shore wind generation is assumed in any of the scenarios; and (2) the reference case assumes no additional offshore wind beyond the Block Island Wind Project. In addition, the reference and more renewables cases reflect solar PV penetrations that are in line with ISO-NE's most recent solar PV forecasts, a forecast which has been increased each year since it was initially developed. The renewable energy totals do not reflect the 254 MW of solar PV projects or the 126 MW wind project that were awarded PPAs in the New England Clean Energy RFP.[4]

The final variable is electricity imports. The Reference Case assumed imports of 2,500 MW, with imports of 3,000 MW assumed in one scenario and 3,500 MW assumed in several scenarios. Electricity imports reduce the reliance on natural gas and depending on their delivery profile and commitments to firm winter deliveries, can significantly enhance the reliability of supply. Subsequent to the release of the fuel security report, Hydro-Quebec was subsequently selected in response to the Massachusetts 83D RFP to provide 9.45 TWh per year over a twenty-year term. This indicates that the reference case and

[4] While this wind project is in New York State, the PPA calls for the delivery of the energy and RECs to the ISO-NE grid such that this renewable generation will be displacing other New England generation.

many of the scenarios are too conservative. However, as discussed above ISO-NE did consider several scenarios with 3,500 MW of imports, which is consistent with such a contract. A study that Power Advisory performed for the Massachusetts Clean Electricity Partnership projected that such a volume of imports would reduce New England's natural gas requirements by about 5% by reducing the requirements for natural gas-fired generation.

ISO-NE notes that Hydro-Quebec, experiences the same or similar weather as New England, and that this is could limit its ability to export power during cold snaps when New England's needs are most acute.[5] The various winter deliverability provisions in the 83D RFP address this concern. With Northern Pass project delivering 9.45 TWh per year over a transmission line with a rated capacity of 1,090 MW, the project will be base loaded. Furthermore, Hydro-Quebec will be required to guarantee this delivery profile during the Winter Peak Period.

ISO-NE Assessment of Fuel Security Risks

To assess the risks posed by these variables, ISO-NE evaluated the operational risks posed under various future fuel-mix scenarios. The study consisted of 23 possible resource combinations for the winter of 2024/2025, that were tested to see if enough fuel would be available to meet demand. ISO-NE acknowledged that these 23 scenarios were not precise predictions of the future system or operating conditions, but were meant to illustrate a range of possible future conditions and risks that could accompany a winter fuel constraint.

The 23 scenarios included: (1) a reference case, which ISO-NE characterized as incorporating likely levels of each variable if the "power system continues to evolve on its current path"; (2) eight scenarios that increase or decrease the level of just one of the five key variables to assess its relative impact; (3) two boundary cases that illustrate what would happen if either all favorable or all unfavorable levels of variables were realized simultaneously. ISO-NE characterizes these as highly unlikely scenarios that provide outer bounds to the scenarios evaluated; (4) four combination scenarios that combine the five key variables at varying levels to represent potential future portfolios; and (5) eight outage scenarios that assume winter-long outages of four major energy or fuel sources.

In almost every scenario, the power system was unable to meet demand and maintain reliability without emergency action by grid operators. Load shedding became necessary in 19 of the 23 scenarios, in order to protect the grid. And all but 1 case, the best case, led to the use of emergency actions, including public requests for energy conservation. This is troubling and an indication of the fuel security risks faced by New England. Unfortunately, it is impossible to quantify how significant these risks are since there is no indication of the underlying probability of these events. We understand that assigning probabilities to such events is difficult and close to impossible. However, care needs to be taken when interpreting these results. We note that one party has wrongly interpreted the study as indicating that there is more than an 80% chance that some or all of New England would face rolling blackouts.[6]

[5] The report indicated that this study does not attempt to quantify these effects.

[6] https://commonwealthmagazine.org/energy/energy-study-draws-divergent-reactions/

Assessment of ISO-NE Scenarios

We believe that these scenarios overstate the fuel security risks faced by New England. The scenarios are overly pessimistic; fail to consider the ability of ISO-NE markets to respond to such conditions; understate changes to the region's generation mix that are likely to better allow New England avoid these system conditions; and fail to consider actions that the region and ISO-NE could take to respond to winter-long outages of critical elements of New England's energy infrastructure.

First of all, ISO-NE notes that the study did not consider prices, but it did "assume that the electricity and fuel markets send price signals sufficient to make full use of the existing electricity and fuel infrastructure as needed" (p. 20). However, in many scenarios the study made static assumptions regarding fuel supply availability. For example, in the reference case it assumed that (1) dual-fuel facilities would have their oil tanks filled only twice; (2) the maximum LNG available was 1 Bcf/day; and (3) imports were limited to 2,500 MW, with an additional 500 MW available from emergency actions. In the reference case, Operating Procedure No. 4 (OP 4), a series of increasingly significant actions that are called to balance supply and demand, would be called for 165 hours, with 53 hours when 10-minute operating reserve would be depleted. Under these conditions, ISO-NE energy prices can be expected to be at a level that attracts imports and additional LNG supplies and assures a high utilization of available LNG. Furthermore, the ISO-NE study indicates that system operating conditions become progressively dire as oil inventories decline. This suggests that there would be a clear signal to the markets to maximize the use of imports and LNG, very likely at levels that are higher than are assumed in many of these scenarios. Furthermore, there is also a longer-term price signal that has not been adequately considered in the study that is likely to influence the level of retirements. The ISO-NE study is a snap shot of the 2024-25 winter. If the conditions portrayed in the operational fuel-security analysis are to occur, one would expect that there would be similar, but less severe price events in prior years that would support the continued operation of oil units that are able to respond to such events. We believe that by failing to consider the strength of this price signal and the response that it engenders the study overstates fuel security risks.

With respect to the reference case, we believe that ISO-NE's characterization that the case reflects the power system continuing to evolve on its current path is inaccurate. The reference case reflects a largely static case, with over seven years little to no evolution of critical variables that would help to mitigate these fuel security risks. As discussed, the reference case fails to account for: (1) 380 MW of solar and wind projects that have been selected in the New England Clean Energy RFP; (2) the 9.45 TWh per year of hydroelectricity that was selected in the 83D RFP;[7] and (3) the prospect of any additional OSW projects being in-service as of 2024-25 winter. We estimate that these resources will produce almost 12 TWh of

[7] We understand that we could be considered as being overly critical and applying hindsight given that the results of the 83D RFP were released more than a week after the ISO-NE study. However, the 83D RFP clearly communicated a goal of contracting 9.45 TWh of clean energy.

energy, resulting in an increase in renewable and clean energy supply of about 10% of ISO-NE's forecast energy demand for 2024.

While not an element of just the reference case, but an element of analysis that affects all the scenarios is the projected growth in natural gas demand for New England gas distribution companies of just under 2% per year. While some utilities are growing sale volumes by expanding their customer bases, we believe that energy conservation could be used to reduce this rate of growth. Furthermore, the study only considers pipeline expansions that were recently completed or are underway.

Second, with respect to eight outage scenarios that reflect winter-long outages of four major fuel or energy sources, these as well are unduly pessimistic. The outages evaluated were the winter-long loss of: (1) two units at Millstone representing 2,100 MW; (2) the loss of Canaport LNG; (3) the loss of Distrigas LNG; and (4) an outage at a compressor reducing natural gas deliveries by 1.2 Bcf/day.

The loss of both units at Millstone for the entire winter season is extremely unlikely. These are two separate units, which for safety reasons have separate facilities. While they share transmission facilities, under Nuclear Regulatory Commission rules there is redundancy and the loss of a transmission corridor as a result of a catastrophic event would result in an immediate mobilization of resources to replace the transmission facilities within the corridor.

With respect to the loss of the Canaport and Distrigas facilities, both have multiple vaporizers that provide redundant vaporization capacity. A season long loss of these LNG facilities would appear to be only possible through a failure of the LNG storage tank, which would represent a major safety threat and as such is likely to be appropriately monitored with adequate engineering safeguards. However, the Distrigas facility has two storage tanks and the Canaport facility three. While there could be temporary damage to offloading facilities that would preclude deliveries. It is difficult to envision damage so severe that it would remove these facilities from service for an entire season. Finally, New England has two offshore LNG facilities that each have a delivery capability of .4 Bcf/day. One of these is rarely used and then other has been never used. With the loss of either of these major LNG facilities, we would expect that these offshore facilities could be used to fill the void. We don't believe that this was adequately considered by the ISO-NE study.

The fourth winter long outage considered by ISO-NE is the loss of a compressor station for an entire season. This outage event is also highly improbable. The pipelines that serve New England have multiple compressor stations and the loss of any one compressor station is unlikely to have such a profound effect on natural gas deliveries. The natural gas pipelines that serve New England have been gradually expanded since they first entered commercial operation. The net effect of this is redundancy in the design of these systems such that the loss of any single compressor is unlikely to have such a profound impact. ISO-NE indicates that the Algonquin pipeline provides about 1.91 Bcf/day, such that a 1.2 Bcf/day reduction would represent 63% of the pipeline's total delivery capability. We believe it highly unlikely that the loss of such a compressor would be sustained for the entire season. Furthermore, as acknowledged by ISO-NE with the loss of such a large volume of pipeline capacity one would expect LNG deliveries to increase including the utilization of the offshore LNG facilities.

In sum, we believe these season long outages to be highly unlikely and as such not reasonable scenarios. An omission in the ISO-NE study is any reasonable level of policy response to what would presumably be viewed as a catastrophic event that likely engender a response to avoid the adverse consequences that ISO-NE's study identifies. We would expect such responses to include supporting the mobilization of existing offshore LNG unloading facilities, temporary relaxation of air permit limits of fossil generating units and potentially the mobilization of energy storage similar to what occurred in southern California after the Aliso Canyon natural gas leak.