UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)))	Docket No. ER18-___-000

PETITION OF ISO NEW ENGLAND INC.
FOR WAIVER OF TARIFF PROVISIONS

ISO New England Inc. ("the ISO") submits this petition pursuant to the Commission's Rule 207[1] for waiver of certain provisions of the ISO's Transmission, Markets and Services Tariff ("Tariff")[2] in order to ensure reliable electric service for New England consumers during the ISO's 2022-2023 and 2023-2024 Capacity Commitment Periods,[3] the 24 months from June 1, 2022, through May 31, 2024.

I. OVERVIEW

The genesis of the requested waivers is the submission by Exelon Generation Company, LLC's ("Exelon") of Retirement De-List Bids for the Mystic Generating Station ("Mystic Station") on March 23, 2018. Those bids notified the ISO of Exelon's intention to retire the generators at its Mystic facility when the existing Capacity Supply Obligations associated with the plant expire on May 31, 2022. According to Exelon, under current

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[1] 18 C.F.R. § 385.207.

[2] The specific provisions of the Tariff that the ISO seeks to waive are identified below at page 6, and are discussed in detail in Section III.C.

[3] Unless otherwise indicated, capitalized terms used in this petition have the meanings ascribed to them in the Tariff. Market Rule 1 is Section III of the Tariff.

market rules in New England, "critical units to the region . . . cannot recover future operating costs including the cost of securing fuel."[4]

The Mystic Station consists of four units, designated as Units 7, 8, 9, and "Mystic Jet." Exelon's Retirement De-List Bids apply to all four units, which have an aggregate nominal summer capacity rating of 2,274 megawatts ("MW"). The Everett Marine Terminal (commonly known as "Distrigas," for the facility's original owner) is adjacent to the Mystic units. Distrigas is a liquefied natural gas ("LNG") import terminal, and the sole source of fuel for Mystic Station Units 8 and 9 ("Mystic 8 & 9"). In addition, Distrigas has firm capacity to deliver up to 435 million cubic feet ("MMcf") per day of natural gas (regasified LNG) into two New England interstate pipelines and a local gas distribution utility. Exelon is in the process of acquiring Distrigas from its current owner, ENGIE North America Inc.[5]

Exelon's planned retirements come at a time when the ISO and New England stakeholders are grappling with a growing threat to the reliable operation of the New England electric system. This threat is posed by the region's increasing reliance on natural gas-fired generation despite essentially static regional natural gas pipeline capacity. The problem is most critical during the winter months, when the region's pipelines are most constrained. The ISO's Operational Fuel-Security Analysis of January 2018, which

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4 *Exelon Generation Files to Retire Mystic Generating Station in 2022, Absent Any Regulatory Solution*, Exelon Corporation (Mar. 29, 2018), http://www.exeloncorp.com/newsroom/exelon-generation-files-to-retire-mystic-generating-station-in-2022.

5 Exelon has stated that its acquisition of Distrigas, on which it expects to close in October 2018, will permit Exelon to honor its current commitments, including its existing obligations to provide capacity from Mystic Station though the ISO's twelfth Capacity Commitment Period, which ends May 31, 2022. *See id.*

focused on potential future scenarios, provided greater clarity on the consequences the region may face if it does not resolve this issue.[6]

In this context, the ISO became particularly concerned about Exelon's planned retirement of Mystic 8 & 9, two combined cycle generators that do not rely on pipeline gas. Mystic 8 & 9 have a combined winter seasonal capacity rating of just over 1,700 MW.

After Exelon's announcement, the ISO studied the retirements of Mystic 8 & 9, and determined that the loss of those units presents unacceptable fuel security risks. Specifically, the ISO's analyses establish that retirement of Mystic 8 & 9 would cause the ISO to deplete 10-minute operating reserves (a violation of mandatory reliability criteria) on numerous occasions and, further, to instigate load shedding—rolling blackouts—during the New England winters of 2022-2023 and 2023-2024.

Compounding these issues, the retirement of Mystic 8 & 9 not only would deprive the New England electric system of those units' 1,700 MW of winter generating capacity with on-site fuel, it also would mean the loss of the Distrigas facility's biggest customer—substantially diminishing Distrigas's financial viability.[7] Should Distrigas also retire, the region's risks of reserve depletion and load shedding would increase, as would the length and severity of such events.

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6 *Operational Fuel-Security Analysis*, ISO New England Inc. (Jan. 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf ("OFSA").

7 *See* Testimony of Richard L. Levitan and Sara Wilmer at 7:5–8, 19-22:2 (stating that retirement of Mystic 8 & 9 likely would be the start of a "death spiral" for Distrigas because its other business is insufficient to enable it to recover its estimated going-forward costs) ("Levitan/Wilmer Testimony"). The Levitan/Wilmer Testimony is attached as Exhibit No. ISO-2.

Given the results of the ISO's studies, the ISO determined that it is essential to retain the services of Mystic 8 & 9 beyond their planned retirement dates. While the Tariff permits the ISO to retain retiring resources to resolve local transmission security issues, it does not contemplate retention to address reliability risks related to fuel security. The ISO therefore seeks the Commission's approval of waivers of the Tariff to the extent necessary to retain Mystic 8 & 9 to ensure the fuel security necessary for reliable operation of the New England electric grid.

The ISO files this waiver request now because Exelon has stated that, if Exelon does not timely obtain the Commission's approval of a satisfactory cost-of-service rate for Mystic 8 & 9, it will elect (as the Tariff permits) not to participate in the next Forward Capacity Auction to be held in February 2019 ("FCA 13") for the performance period starting in June 2022, and will retire Mystic 8 & 9 unconditionally.[8] Accordingly, the ISO requests that the Commission approve the waivers proposed in this petition by no later than July 2, 2018, to conform to the Tariff's prescribed schedule for market participants to commit to participation in FCA 13.

The Tariff waivers that this petition seeks are necessary: (1) to authorize the retention of Mystic 8 & 9 for fuel security, rather than for local transmission needs; and (2) to extend certain deadlines to accommodate Exelon's requirements. As detailed in Section

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8 The ISO has chosen to meet the immediate need to address Exelon's Retirement De-List Bids by seeking a waiver of certain Tariff provisions, rather than proposing changes to its Tariff. Those Tariff changes are best developed through New England's robust stakeholder process. While the ISO has begun work with stakeholders to develop criteria for the retention of resources to ensure fuel security, the ISO must address Exelon's Retirement De-List Bids before this stakeholder process will be completed.

III.D below, the ISO's requested waivers comport with the Commission's four-part standard for such requests.[9]

The ISO anticipates that, soon after the filing of this petition, Exelon will file its Cost of Service Agreement[10] for the Commission's review and approval under section 205 of the Federal Power Act.[11] As part of that filing, Exelon will ask the Commission to approve Exelon's proposed cost of service for Mystic 8 & 9 as the basis for establishing a rate to be effective for Mystic 8 & 9 during the 2022-2023 and 2023-2024 Capacity Commitment Periods. As explained in Section III.C.3 below, Exelon's required two-year term for the Cost of Service Agreement will ensure the availability of Mystic 8 & 9 until the ISO and its stakeholders develop, and market participants have an opportunity to make any investments needed to implement, a market-based fuel security solution for the region.

Consistent with the Commission's policy and precedent,[12] the ISO takes these steps only as a last resort to ensure reliable electric service in New England during the 2022-2024 Capacity Commitment Periods. The ISO remains committed to ensuring the efficiency, fairness, and efficacy of the wholesale electricity markets it administers. It is entering into a cost of service agreement with Exelon for Mystic 8 & 9 and submitting this

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[9] *See, e.g.*, *Consumers Energy Co.*, 150 FERC ¶ 61,125, at P 48 (2015), *reh'g denied*, 155 FERC ¶ 61,036 (2016); *DTE Electric Co.*, 150 FERC ¶ 61,127, at P 45 (2015), *reh'g denied*, 155 FERC ¶ 61,036 (2016).

[10] The Tariff includes a pro forma Cost of Service Agreement for a capacity resource that proposes to retire, and then is retained for reliability and elects a cost of service rate. Market Rule 1, Section III, Appendix I.

[11] 16 U.S.C. § 824d. Section III.13.2.5.2.5.1(b) of the Tariff provides that the Cost of Service Agreement will be filed under section 205.

[12] *See, e.g., Devon Power LLC*, 103 FERC ¶ 61,082, at P 31 (2003) (stating that cost-based, reliability must-run contracts are appropriate in a region with competitive wholesale markets only as a last resort).

petition because, in the ISO's best judgment, both are essential at this juncture to meeting the ISO's overriding obligation to maintain the reliability of the New England electric system.

Accordingly, the ISO requests waiver of application of the following provisions of the Tariff to Exelon's Retirement De-List Bids for Mystic 8 & 9, with such waivers to be effective on or before July 2, 2018, and continuing through the term of the Cost of Service Agreement for Mystic 8 & 9 that Exelon will file with the Commission in a separate docket:

- Market Rule 1, Section III.13.1.2.3.1.5.1, relating to review of Retirement De-List Bids for local reliability needs.
- Market Rule 1, Section III.13.2.5.2.5, relating to the criteria applied in reviewing a Retirement De-List Bid for a local reliability need.
- Open Access Transmission Tariff, Attachment K, relating to evaluating upgrades to the transmission system to address a local reliability need.
- Market Rule 1, Sections III.13.2.5.2.5 and III.13.2.5.2.5.1, relating to retaining a capacity resource until the underlying reliability need is addressed.
- Market Rule 1, Section III.13.2.3.2(c), relating to permitting a supplier whose resource is being retained for reliability to submit a Dynamic De-List Bid in the auction.
- Market Rule 1, Sections III.13.1.2.3.1.5.1(c) and III.13.2.5.2.5.1(b), relating to compensation for a resource that is retained for reliability.
- Market Rule 1, Section III.13.2.5.2.5.2, relating to capital expenditures for a resource retained for reliability.
- Market Rule 1, Sections III.13.1.2.4.1 and III.13.1.2.3.1.5.1(d), relating to the deadlines for a capacity supplier that has submitted a Retirement De-List Bid to elect unconditional retirement or elect to be retained for an identified reliability need.

The ISO respectfully requests that the Commission issue its decision in this matter no later than July 2, 2018. A decision by this date is necessary because Exelon and other participants must decide no later than July 6, 2018 whether to participate in FCA 13.[13]

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[13] At the time of this filing, the ISO is discussing with stakeholders potential modifications to the Retirement De-List Bid rules. Those modifications, if

II. THE ISO MUST RETAIN MYSTIC 8 & 9 TO ENSURE THE FUEL SECURITY NECESSARY FOR RELIABLE ELECTRIC SERVICE IN NEW ENGLAND IN 2022-2024

In his attached testimony, Mr. Peter T. Brandien, the ISO's Vice President of System Operations, explains the importance of fuel security to system reliability, and why fuel security justifies retaining Mystic 8 & 9.[14] Mr. Brandien notes that fuel security is particularly challenging in New England because the region does not have any indigenous fuel production or extraction.[15] 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.[16] These factors mean that fuel procurement, transportation, and storage have a pivotal role in power system operations. This is especially true with respect to natural gas.[17]

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implemented for FCA 13, would require changes to certain Tariff deadlines to provide the ISO's Internal Market Monitor and market suppliers an additional month to make decisions regarding outstanding Retirement De-List Bids (including the bids that are the subject of this waiver petition). These potential Tariff changes are unrelated to the Tariff provisions at issue in this waiver petition, and allowing for an additional month to make decisions on outstanding Retirement De-List Bids would ultimately not prevent the need for waiver of the relevant deadlines as requested in this petition. For these reasons, and because the ISO is not yet certain it will proceed with the potential Tariff changes (and even if it does, there is no assurance that the Commission will accept them for implementation for FCA 13), the ISO has not factored the potential deadline changes into the timeline it is proposing in this petition.

14 The Testimony of Peter T. Brandien on Behalf of ISO New England Inc. is attached to this petition as Exhibit No. ISO-1 ("Brandien Testimony").

15 *Id*. at 8:17–20.

16 *Id*. at 8:20–22.

17 *Id*. at 9:3–9.

Over the past seventeen years, New England's generation fleet has migrated from extensive reliance on oil and coal to natural gas. Natural gas was used to generate just 15 percent of New England's electricity in 2000, but it fueled production of 49 percent of the region's electricity in 2016, and that is expected to grow to 56 percent by 2026.[18]

However, New England's natural gas pipeline infrastructure has not grown commensurately with the region's use of gas to fuel the electric generation fleet. The region's interstate gas pipelines have been designed and built to meet the peak demands of the entities contracting for that capacity. In New England, most gas pipeline capacity is under contract to the local natural gas distribution utilities that serve retail gas consumers pursuant to their obligation to provide service under all conditions.[19]

Natural gas-fired power plants in New England typically rely on capacity that local utilities temporarily release in the secondary market. This secondary capacity, by definition, is available only 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 the coldest winter weather—pipeline capacity is unavailable for natural gas-fired generators.[20]

This has become increasingly problematic for the ISO as it strives to maintain reliable electric service during New England's cold winters. Mr. Brandien outlines the

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18 *See* OFSA at 11; ISO New England Inc., https://www.iso-ne.com/system-planning/system-plans-studies/rsp/ (last visited May 1, 2018) (the 2017 Regional System Plan is available for download by navigating below to "Regional System Plan Materials" and under "Documents" click "2017 Regional System Plan" and go to page 98 of the document).

19 Brandien Testimony at 9:12–16.

20 *Id*. at 10:4–6.

issue very clearly when he describes the ISO's experience over a 13-day stretch in the winter of 2017-18 during which New England endured below-normal temperatures, including ten days of temperatures more than 10 degrees below normal. During those thirteen days, natural gas-fired generation produced only about 24 percent of New England's electricity, rather than the nearly 50 percent it produced prior to the cold spell. Conversely, oil- and coal-fired resources generated "a full one-third of all energy . . . while in the preceding year such resources had provided just two percent (yearly average) of New England's electricity."[21] Because Mystic 8 & 9 do not rely on New England's gas pipeline network for fuel, their proposed retirement presents critically important issues for the reliability of the New England electric system.

A. Retirement of Mystic 8 & 9 Would Create Unacceptable Risks to Reliability

Mr. Brandien also details the ISO's analyses of Exelon's retirement bids, which show that the loss of Mystic 8 & 9 would create serious reliability risks for the New England electric grid. These studies focus on the two winters following the planned retirement of Mystic 8 & 9—the winters of 2022-2023 and 2023-2024 (the "Mystic Retirement Studies"). The Mystic Retirement Studies use the same system model employed by the ISO's Operational Fuel-Security Analysis (sometimes referred to herein as the "OFSA") regarding winter 2024-2025.[22]

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21 Brandien Testimony at 13:17– 20.

22 Peak load forecasts were adjusted and certain other input assumptions were modified from those used in the OFSA to correspond to expected conditions during the winters of 2022-2023 and 2023-2024.

For purposes of this petition, the most important results of the ISO's assessments are stated in terms of the frequency of instances when (1) the system's 10-minute operating reserves would be depleted (a violation of reliability criteria established by the North American Electric Reliability Corporation ("NERC")); and (2) the electric system would be unable to produce sufficient energy to meet system demand, and the ISO therefore would have to shed load, i.e., impose rolling blackouts. Mr. Brandien testifies that both the Mystic Retirement Studies and the Operational Fuel-Security Analysis support the ISO's conclusion that retaining Mystic 8 & 9 for 2022-2023 and 2023-2024 is necessary to ensure reliable winter electric service in New England.[23]

1. The Mystic Retirement Studies Validate the ISO's Decision to Retain Mystic 8 & 9

Mr. Brandien explains that the Mystic Retirement Studies focused specifically on the consequences of the proposed retirement of Mystic 8 & 9 in the 2022-2024 timeframe. Mr. Brandien testifies that the Mystic Retirement Studies establish that, even when Distrigas is assumed to remain in service despite retirement of Mystic 8 & 9 (a scenario about which the ISO's witnesses Mr. Richard Levitan and Ms. Sara Wilmer cast doubt[24]), the loss of the Mystic units, in itself, presents serious operational risks for the New England electric system.[25]

For example, the ISO's analysis indicates that, if Mystic 8 & 9 were retired in 2022, there would be violations of reliability criteria regarding 10-minute operating reserves, even under highly optimistic assumptions during the winter of 2022-2023—and even if

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23 Brandien Testimony at 4:15–22.

24 Levitan/Wilmer Testimony at 18:19 – 22:2.

25 Brandien Testimony at 42:10 – 47:20.

Distrigas remained in service.[26] Specifically, Mr. Brandien's Table 2 shows that 10-minute operating reserves would be depleted during multiple hours of winter operations, even assuming that 1.0 billion cubic feet ("Bcf") per day of LNG would be available (in effect, that Distrigas would remain in service), 3,500 MW of energy would be available on the ISO's external interties for the entire winter, and oil tanks at all dual-fuel generation facilities would be fully refilled twice. The system's vulnerability is well illustrated by the outcome when imports are assumed instead to be 3,000 MW, and dual-fuel oil tanks are replenished only once: 51 hours of depletion of 10-minute reserves and load-shedding totaling more than 11,000 MW-hours across six days during the 2022-2023 winter.

2. When the Studies Account for the Likely Loss of Distrigas as Well, the Case for Retaining Mystic 8 & 9 Is Even More Compelling

The Mystic Retirement Studies and the Operational Fuel-Security Analysis include scenarios representative of the event that, if Mystic 8 & 9 were taken out of service, Distrigas would retire also.[27] The results of those scenarios provide even more compelling support for the ISO's determination that Mystic 8 & 9 must be retained.

Table 1 in Mr. Brandien's testimony details the results of the studies regarding the winter of 2022-2023. Assuming LNG of 0.8 Bcf per day (still more than actual volumes on all but a few days during recent winters, but illustrative of retirement of Distrigas) during

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[26] Mr. Brandien also explains why depletion of 10-minute operating reserves is a particularly critical aspect of reliability in New England, due to the region's radial electrical location relative to the remainder of the Eastern interconnection. Brandien Testimony at 41:3–14.

[27] *See* Levitan/Wilmer Testimony at 18:19 – 22:2 (explaining that the retirement of Distrigas's largest customer, Mystic 8 & 9, would create significant doubt regarding Distrigas's continuing commercial viability).

the winter of 2022-2023, along with the very favorable assumptions of 3,500 MW of energy imports for the entire winter, and two full replenishments of oil tanks at all dual-fuel facilities, the ISO's analysis indicates the New England electric system would risk facing 37 hours during which 10-minute operating reserves would be fully depleted, and could endure load shedding on five days that would entail more than 5,000 MW-hours of unserved demand. As shown in Mr. Brandien's Table 4, the same scenario indicates depletion of operating reserves and load shedding of similar magnitude during the winter of 2023-2024.

Though completed prior to Exelon's submission of its Retirement De-List Bids for Mystic Station, the OFSA is also relevant to the ISO's decision to retain Mystic 8 & 9. Among the operational scenarios analyzed in the OFSA was a winter-long outage of the Distrigas facility in 2024-25. Under the OFSA's Reference Case assumptions, the loss of the Distrigas facility and the concurrent loss of Mystic 8 & 9 would lead to 87 hours of depletion of 10-minute operating reserves and 24 hours of load shedding over seven days during the 2024-25 winter.

Mr. Brandien notes that even this unwelcome result may be optimistic: the OFSA Reference Case assumes that other LNG facilities would increase their deliveries into New England pipelines sufficiently to replace 100 percent of the lost Distrigas LNG. In fact, the amounts of LNG actually available to the New England energy system rarely reach the study's assumed 1.0 Bcf per day of LNG.[28]

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[28] Brandien Testimony at 33:15–22, 38:1–7.

3. The Mystic Retirement Studies Use Conservative Assumptions About Likely System Conditions During the Study Period, and Therefore May Understate the Problem

Importantly, Mr. Brandien points out that the stark projections of the Mystic Retirement Studies probably tend to *understate* the problems that retirement of Mystic 8 & 9 would create. That understatement occurs because a number of the assumptions used in the Mystic Retirement Studies are more favorable to system reliability than actual conditions the ISO has experienced during recent winters. These assumptions include:

- All resources that cleared the FCA 12 capacity auction in February 2017 will be available in the 2022-2023 and 2023-2024 Capacity Commitment Periods, and there will be no retirements except those that have already submitted de-list bids. Thus, the system reflected in the Mystic Retirement Studies may include more generating capacity than will be available in the winters under study.

- All transmission facilities are available at their rated capacities for the entire 90-day study period.

- All units run as dispatched without regard for emissions limits (in reality, the ISO is concerned that state emissions limitations may limit the ability of the oil-fired fleet to run in cold weather).[29]

- Fuel delivery logistics are unconstrained, i.e., LNG and oil supplies are always replenished as and when needed.[30]

Even under these optimistic assumptions, together with assuming that Distrigas would remain in service after retirement of Mystic 8 & 9, the projections reported in Mr. Brandien's Table 5 demonstrate that retirement of the Mystic units is reasonably likely to result in violations of reliability criteria established by NERC and the Northeast Power

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[29] Vamsi Chadalavada, *Cold Weather Operations*, ISO New England Inc., 23 (Jan. 16, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf.

[30] Brandien Testimony at 39:10–11.

Coordinating Council ("NPCC") for 10-minute operating reserves, as well as the prospect of load shedding on some occasions, during the winters of 2022-2023 and 2023-2024.

4. Factoring in Even Limited Contingencies Significantly Increases the Reliability Risks

When the ISO factored into the Mystic Retirement Studies even limited contingencies in addition to the retirement of Mystic 8 & 9, the risks of reliability violations increased significantly. Table 6 in Mr. Brandien's testimony shows, for example, that with assumed outages of 1,000 to 1,250 MW of other system facilities—similar to the amounts actually experienced during the winter 2017-2018 cold spell—load shedding could be required on as many as five days during the winter of 2023-2024.[31] Per the testimony, this load shedding would occur even if Distrigas remained in service and total LNG deliveries could be sustained at 1 Bcf per day (well above actual experience on all but a few days in recent years) on average across the entire winter—and with maximum LNG deliveries on thirty-one days.[32] This outcome clearly reveals the system's extremely thin margin for error if Mystic 8 & 9 are retired.

When, under these limited contingencies, the retirement of Mystic 8 & 9 is accompanied by retirement of Distrigas—a potential outcome if Mystic 8 & 9 are shut down—the picture is even bleaker. For example, during the winter of 2023-2024, the ISO's analysis projects 41 hours of full depletion of 10-minute operating reserves and load shedding on five days.[33]

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31 *Id*. at 46:12–15 & Table 6.

32 *Id*. at 33:15–22.

33 *Id*. at 23:16–21 & Table 4, line 3. Again, these results are obtained even under the highly optimistic scenario of: (1) sustained imports from external sources of 3,500 MW of energy; (2) two full replenishments of oil storage inventories at *all* oil-fired

This discussion provides only an overview of the analyses Mr. Brandien presents in his testimony. Nevertheless, even this abridged version of the ISO's studies highlights the seriousness of the reliability risks presented by the proposed retirement of Mystic 8 & 9. It also underscores the ISO's conclusion that it must retain Mystic 8 & 9 for the 2022-2023 and 2023-2024 Capacity Commitment Periods to ensure the fuel security the ISO requires to maintain reliable winter service for New England's electricity consumers.

III. THE PROPOSED WAIVERS

A. Exelon's Conditions for Agreeing to Delay Retirement of Mystic 8 & 9

Exelon has indicated that it will retire both units at the end of its current capacity obligations for Mystic Station in May 2022, unless it obtains regulatory certainty, prior to taking on additional capacity supply obligations, that it can recover its full costs of operating Mystic 8 & 9 under a cost of service arrangement. Specifically, Exelon is willing to continue operation of Mystic 8 & 9—i.e., to delay retirement—only if it receives certainty before the running of FCA 13 in February 2019 that it can recover its full cost of service for Mystic 8 & 9 for the two-year period from June 1, 2022 through May 31, 2024 (corresponding to the thirteenth and fourteenth Capacity Commitment Periods of the Forward Capacity Market). In the absence of this outcome, Exelon has indicated to the ISO that it will elect unconditional retirement, and Mystic 8 & 9 will not participate in the February 2019 auction.

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and dual-fuel generators before and during the winter; and (3) LNG supplies of 0.8 Bcf per day (rather than 1.0 Bcf per day with Distrigas in service, but still high relative to recent history), with maximum LNG deliveries sustained for thirty-four days.

Exelon states that its decision to begin the retirement process for the Mystic units is grounded in the performance of New England's wholesale markets.[34] For several years the ISO as well as stakeholders have recognized the region's increasing lack of fuel diversity and the need to improve fuel security.[35] Within the wholesale electricity markets, the most significant contribution to these efforts has been the development of the Pay for Performance ("PFP") capacity market model, the first performance period of which will go into effect in June 2018.[36] While PFP's full payment and penalty rate will not be achieved until 2025, even once fully implemented, PFP cannot be expected to resolve the region's fuel security challenges by itself, particularly in light of the significant opposition in the region to investments in fuel supply infrastructure.[37]

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34 *See supra* note 4.

35 *See Final Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 "Cold Snap,"* ISO New England Inc. (Oct. 12, 2004), https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf (addressing studies undertaken to evaluate fuel security concerns in light of the region's increasing reliance on natural-gas fired generation); *2011-2012 Regional Electricity Outlook*, ISO New England Inc., (June 20, 2011), https://www.iso-ne.com/static-assets/documents/aboutiso/fin/annl_reports/2000/2011_reo_2010_financials.pdf (discussing concerns over the region's reliance on natural gas and winter pipeline constraints); *Prepared Statement for Gordon van Welie for U.S. Department of Energy Quadrennial Energy Review Meeting*, (Apr. 21, 2014) https://www.iso-ne.com/static-assets/documents/pubs/pubcomm/pres_spchs/2014/van_welie_statement_4_21_14.pdf (discussing the natural gas reliance issues and the New England state governors' initiative to address the need for additional natural gas pipeline and electric transmission infrastructure).

36 The ISO has undertaken a number of other changes to increase market efficiency, create incentives for resources to perform when needed, and improve gas-electric coordination. See Brandien Testimony at 16:1 – 18:18 for a discussion of some of these changes.

37 In filing the PFP market rules, the ISO addressed fuel diversity concerns, and the failure of the then-prevailing capacity market design to provide sufficient incentives for suppliers to enter into short notice and firm fuel contracts and to

The region is now poised to confront this issue through development of a market-based solution for fuel security.[38] Nevertheless, the three-year lead time of the Forward Capacity Market means that resources must decide well in advance of each capacity performance period whether a market-based solution will develop and mature to a point of properly valuing fuel security by the time the performance period arrives, or whether instead to utilize the de-list process to try to obtain an out-of-market rate. For a resource that is unwilling to accept compensation based on its going-forward costs as reflected in a de-list bid price, the only meaningful option under the Tariff is to use the retirement process to file for a cost of service rate.

The ISO's immediate priority in response to Exelon's decision is to retain Mystic 8 & 9 for fuel security until a market-based solution to this issue can be developed and implemented. The current Forward Capacity Market rules do not permit the ISO to retain Mystic 8 & 9 under Exelon's stated conditions. Therefore, the ISO asks the Commission to waive the relevant portions of the Tariff, as identified herein, to the extent necessary to

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maintain much-needed dual fuel capability. *See* Filings of Performance Incentives Market Rule Changes of ISO New England Inc. and New England Power Pool, Docket No. ER14-1050-000, Attachment I-1 at 3, 10-11 (Jan. 17, 2014). Since that time, however, the region has faced continued opposition to the development of additional natural gas pipeline capacity, and added environmental restrictions have degraded the potential value of new investments in dual fuel capability.

38 The ISO and New England stakeholders are focused on the critical task of developing a market-based solution to resolve the region's fuel security risks and properly value the contributions that resources like Mystic 8 & 9 make in ensuring fuel security. These efforts began formally in January of this year, when the ISO published the OFSA. They have continued with a series of stakeholder meetings to evaluate the OFSA, further define the fuel security risks and the means of addressing those risks, and to begin the process of developing a market-based solution. *See Reliability Committee*, ISO New England Inc., https://www.iso-ne.com/committees/reliability/reliability-committee/ (last visited May 1, 2018).

permit retention of Mystic 8 & 9 under a cost-based rate (to be determined separately) during the 2022-2023 and 2023-2024 Capacity Commitment Periods.

B. Overview of the Forward Capacity Market's Current Treatment of a Retirement De-List Bid

The ISO market rules governing Retirement De-List Bids provide suppliers with a mechanism for permanently retiring an existing capacity resource from the Forward Capacity Market by submitting a de-list bid in the annual qualification period leading up to the Forward Capacity Auction. In March of the year prior to the auction, the supplier is required to submit its Retirement De-List Bid, specifying the price it must receive in the auction if it is to remain in the capacity market for another year.[39] The IMM evaluates and, in some instances, adjusts that price to ensure it reflects the going-forward costs of providing capacity from the resource that is subject to the retirement bid.[40] The IMM notifies the supplier of its determination in mid-June of the year prior to the auction, and then files its determination with the Commission in July.[41]

A supplier may choose to accept the price determined by the IMM—meaning that it will participate in the auction and retire only if the auction clears below its IMM-authorized retirement-bid price (as approved by the Commission, making it the "Commission-approved" retirement bid price)—or it can choose to retire regardless of the IMM's price determination, in which case it will not participate in the auction at all.[42] The Tariff refers to these two options, respectively, as "conditional" and "unconditional"

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[39] Market Rule 1, Section III.13.1.2.3.1.5.

[40] Market Rule 1, Section III.13.1.2.3.2.1.

[41] Market Rule 1, Sections III.13.1.2.4 and III.13.8.1

[42] Market Rule 1, Section III.13.1.2.4.

treatment. This choice must be made within ten business days of receiving the IMM's determination—i.e., in early July of the year prior to the auction.[43]

In addition to the IMM's price evaluation, under certain conditions, the ISO must perform a reliability review to evaluate whether the supplier's capacity is needed to address a local transmission need. This review is necessary if either: (1) the IMM-determined price for a Retirement De-List Bid is above the FCA starting price; or (2) the supplier has opted to have the resource reviewed for reliability.[44] Under this review, capacity is deemed to be needed for reliability "if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules" for the "sole purpose of addressing a local [transmission] reliability issue."[45] This review must be performed within a month after the IMM files its determination on the retirement bids with the Commission—i.e., by mid-August of the year prior to the auction.[46]

If the ISO determines that the resource is needed for reliability under the standard specified in the Tariff, the supplier has ten business days to decide whether to accept the ISO's request to retain the resource for reliability, or whether instead to retire despite the reliability determination.[47] If the supplier chooses to remain, it will receive, at its choice, either the Commission-approved retirement bid price, reflecting the resource's going-forward costs, or a cost of service rate determined by the Commission following section

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[43] Market Rule 1, Section III.13.1.2.4.

[44] Market Rule 1, Section III.13.1.2.3.1.5.1.

[45] Market Rule 1, Section III.13.2.5.2.5(a).

[46] Market Rule 1, Section III.13.1.2.3.1.5.1(b).

[47] Market Rule 1, Section III.13.1.2.3.1.5.1(d).

205 proceeding.[48] A supplier's choice to file for a cost of service rate must be made within approximately six months following the auction, and the rules generally anticipate that a cost of service proceeding will be commenced after the auction.[49]

C. Waivers of the Following Forward Capacity Market Tariff Provisions Are Necessary to Permit the ISO to Retain Mystic 8 & 9 for Fuel Security

Waivers of the Tariff are necessary in this case for three reasons. First, waiver is needed to permit the ISO to retain Mystic 8 & 9 for reliability based on its determination that the resources are needed to provide region-wide fuel security for the 2022-2024 time period. Second, waiver is necessary to exempt the Mystic 8 & 9 Retirement De-List Bids from the Tariff's local reliability review requirement for FCAs 13 and 14. This step properly follows from the ISO's determination that Mystic 8 & 9 must be retained to maintain fuel security, rather than to address a local reliability issue. Third, waiver is necessary to permit Exelon to delay, until January 2019, its decision on whether to proceed with retirement or accept the reliability retention, allowing the maximum amount of time possible for the Commission to rule on Exelon's cost of service for Mystic 8 & 9 before the next capacity market auction.

Prompt action by the Commission on the proposed waivers is required because the Tariff prescribes certain deadlines in the coming months for market participants that seek

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48 Market Rule 1, Section III.13.2.5.2.5.1(b).

49 Section III.13.2.5.2.5.1(b) contemplates that a resource retained for reliability may elect to be compensated for its capacity under the terms of a cost of service agreement, the form of which is contained in Appendix I to Market Rule 1. This election must be made within six months following the ISO's filing of the FCA results. The rules do not prohibit the supplier from electing cost of service treatment prior to the auction.

to qualify for FCA 13 in February 2019. Specifically, as applied to Exelon's Retirement De-List Bids, the IMM must provide its calculation of the appropriate price for the bid to Exelon by June 21, 2018. Exelon would then have until July 6, 2018 to decide whether to retire Mystic 8 & 9 unconditionally. By July 21, 2018, the IMM is required to make an informational filing with the Commission concerning retirement de-list bids. The IMM's filing initiates a process under which Exelon would have the right to challenge the IMM's calculation, and to request cost-of-service rates for Mystic 8 & 9. However, by the time Exelon would obtain the cost-of-service determination for Mystic 8 & 9 under this timeline, it would have forfeited its right to retire unconditionally, and very likely would have already committed to take on capacity obligations for the 2022-2023 Capacity Commitment Period. This timeline under the Tariff is not compatible with Exelon's stated unwillingness to bear the risk of committing to capacity obligations before it knows the cost of service that will be allowed for Mystic 8 & 9.

1. Mechanism to Retain Mystic 8 & 9 for Reliability and Treatment in FCAs 13 and 14

Section III.13.1.2.3.1.5.1 of the Tariff addresses the ISO's reliability review of Retirement De-List Bids. It indicates that a review will be conducted according to Section III.13.2.5.2.5 for any IMM-approved Retirement De-List Bid that is above the FCA starting price, or when the supplier has opted to have the resource reviewed for reliability. The ISO is requesting waiver of Section III.13.1.2.3.1.5.1, to the extent necessary for the ISO to treat the Mystic 8 & 9 retirement bids as if they were above the Forward Capacity Auction starting price, despite the fact that the IMM has not yet issued its determination regarding those bids.

Treating the bids as though they exceeded the auction starting price triggers the ISO's obligation to evaluate whether Mystic 8 & 9 should be retained to address a local reliability need under the criteria in Section III.13.2.5.2.5. Therefore, the ISO also requests waiver of Section III.13.2.5.2.5 to allow the ISO to determine that Mystic 8 & 9 are needed for reliability without performing the evaluation contemplated in Section III.13.2.5.2.5. As explained above, Section III.13.2.5.2.5 deems a resource to be needed for reliability if it is necessary to address "a local reliability issue," and the resource's retirement would result in the violation of NERC or NPCC criteria, or of ISO New England System Rules. Instead, with the proposed waiver of Section III.13.2.5.2.5, Mystic 8 & 9 will be retained to provide the fuel security needed to ensure reliability, as described above. While retaining Mystic 8 & 9 for fuel security addresses a New England-wide reliability need—not a "local reliability issue"—if Mystic 8 & 9 are not retained, there is a significant likelihood that the ISO would be unable to operate the system without violating the NERC reliability criteria applicable for local reliability issues.[50]

2. Waiver of Requirement to Perform Local Reliability Review and Transmission Upgrades

While it is possible that, if evaluated under the local reliability need standard of Section III.13.2.5.2.5, the ISO would determine that Mystic 8 & 9 are needed to ensure local transmission reliability in the Southeast New England zone—thereby triggering the process for evaluating upgrades to the transmission system[51]—the ISO does not believe

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[50] Brandien Testimony at 42:8–9.

[51] *See* Tariff, Section II, Attachment K.

that performing this evaluation or commencing upgrades at this time is necessary or prudent.

The region would realize little benefit from planning (and executing) a transmission solution, should it exist, to a problem that is likely to change, and which potentially may be resolved entirely in the ensuing years while Mystic 8 & 9 remain in operation under the anticipated cost of service agreement. As the region evolves, it is reasonable to expect potentially significant changes in resource mix, load levels and other factors that will impact the nature and severity of any transmission security issue. The markets will also evolve during this time period—including through the addition of a market-based solution to the existing fuel security issues—and this evolution may affect transmission security issues as well. Addressing a local transmission reliability need at this time would cause the region to incur potentially significant costs without a clear understanding as to whether that need will persist and, if it does, what shape it will take when Mystic 8 & 9 ultimately retire.

Accordingly, the ISO is requesting waiver of the obligation under Section III.13.2.5.2.5 to evaluate whether Mystic 8 & 9 should be retained for local reliability, as well as (to the extent it might attach) the obligation to pursue any transmission upgrades that might be required under Attachment K to the OATT to address any such local reliability need. Instead, the retirement of Mystic 8 & 9 will be included in a future Attachment K needs assessment, with the goal of resolving any transmission issue before the end of the term of the cost of service agreement.

3. Retaining Mystic 8 & 9 for Two Capacity Commitment Periods

Sections III.13.2.5.2.5 and III.13.2.5.2.5.1 contemplate that a resource which proposes to retire may be retained for the one-year Capacity Commitment Period for which the resource submitted its Retirement De-List Bid, and thereafter until the underlying reliability need is addressed.[52] The ISO seeks waiver of this provision to the extent necessary to permit Exelon and the ISO to enter into a cost-of-service agreement to retain Mystic 8 & 9 for a two-year term covering Capacity Commitment Periods 13 and 14, from June 2022 through May 2024.

The ISO believes that the fuel security issues for which it seeks to retain Mystic 8 & 9 can only be addressed through the development of an appropriate market mechanism. The ISO may implement a market-based fuel security solution as soon as 2020 if that solution is decoupled from the capacity market, or as late as 2024 if that solution is part of the Forward Capacity Market. However at this time, it is unclear what form this solution will take, and therefore it is difficult to predict when the market may reach a sufficient level of maturity to resolve the fuel security issues that require Mystic 8 & 9's retention.

There are many infrastructure solutions that can address the fuel system constraints in the region in the long term. These include additional gas pipelines, LNG storage, dual-fuel capability (with appropriate air permits), firm renewable energy (e.g., imports of hydro energy, or off-shore wind coupled with significant electricity storage), and investments in energy efficiency measures. However, experience teaches that these solutions are expensive, are often difficult to site, and will take time to develop. Some may be possible

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[52] While these provisions of Market Rule 1 are not explicit, Section 2.2.1 of the Form of Cost-of-Service Agreement in Appendix I to Market Rule 1 contemplates a term of at least one year, with termination by the ISO upon 120-days notice once the resource is no longer needed for reliability. Further, Section III.13.2.5.2.5.3 indicates that the resource will be retired at the end of the initial Capacity Commitment Period "if the reliability need that resulted in the rejection for reliability is met" (and the Commission does not otherwise remove the obligation to retire or extend the retirement date). Market Rule 1, Section III.13.2.5.2.5.3.

in reaction to wholesale market incentives (e.g., additional dual fueling) and will require state action to allow the requisite emissions during the winter; others will depend almost exclusively on state action (possibly among multiple states) to both contract for and site the required infrastructure. In the meantime, the region will have to utilize and retain existing infrastructure.

If the market-based solution is implemented through the capacity market, the fuel security provided by Mystic 8 & 9 is necessary to bridge the gap during the three years after resources take on fuel security obligations through FCA 15 in 2021 and before they are required to begin performance in June 2024. If the market-based solution is implemented in 2020 (i.e., outside of the Forward Capacity Market, such as through a shorter-term forward market), the fuel security of Mystic 8 & 9 still will be critical during the infancy of that market, to ensure that sufficient, fuel-secure resources are available until the new approach is capable of providing all the required services.

More fundamentally, Exelon has stated that it will not continue to operate Mystic 8 & 9 if it does not obtain a two-year reliability must run ("RMR") agreement. For the reasons explained in this petition and the ISO's accompanying testimony, the ISO has determined that retaining Mystic 8 & 9 is necessary for the fuel security needed to maintain reliability, and to avoid a significant risk of load-shedding during the 2022-2023 and 2023-2024 winters. In the light of this acute need, the ISO has concurred with Exelon's requirement of a two-year RMR (cost of service) agreement. In sum, the ISO asks the Commission to waive the relevant provisions of Section III.13.2.5.2.5 of the Tariff to the extent necessary to permit the ISO to retain Mystic 8 & 9 under a two-year cost of service agreement.

4. Treatment of Retirement Bids in the FCA

If the Mystic 8 & 9 units are retained for reliability, then, pursuant to sub-section (c) of Section III.13.1.2.3.1.5.1 of the Tariff, the Mystic 8 & 9 retirement bids will be rejected, and Mystic 8 & 9 will be entered into FCAs 13 and 14 as price takers under the Forward Capacity Auction clearing rules of Section III.13.2.3.2(c).[53] To ensure this outcome, Exelon will not be permitted to submit Dynamic De-List Bids for Mystic 8 & 9 in the capacity auctions held during the term of the Cost of Service Agreement. The ISO therefore also requests waiver of Section III.13.2.3.2(c) to the extent that it otherwise would permit Exelon to submit such bids in FCA 13 or FCA 14.[54]

5. Compensation

Granting the proposed waivers described above will mean the Mystic 8 & 9 retirement bids will be treated as rejected for reliability and in excess of the FCA 13 starting price. Therefore, Section III.13.2.5.2.5.1(b) provides that Exelon may elect to be compensated for its capacity under the terms of a cost of service agreement, the form of which is contained in Appendix I to Market Rule 1. This election must be made within six months following the ISO's filing of the FCA results, with a cost of service proceeding to be completed prior to the commencement of the Capacity Commitment Period.

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53 *See* Market Rule 1, Section III.13.2.5.2.5(g) ("If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, FCA or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the FCA and shall be compensated as described in Section III.13.2.5.2.5.1.").

54 In the event Exelon chooses unconditional retirement, then the existing rules will apply to determine how Mystic 8 & 9 will be represented in FCA 13.

Exelon has stated that it will file for a cost-of-service determination for Mystic 8 & 9 once the ISO indicates (as it does through the filing of this waiver request) its intent to retain Mystic 8 & 9 for the 2022-2023 and 2023-2024 Capacity Commitment Periods. While Section III.13.2.5.2.5.1(b) of the Tariff does not expressly prohibit a supplier from electing cost-of-service treatment prior to the relevant Forward Capacity Auction, for the avoidance of doubt, the ISO requests waiver of Sections III.13.1.2.3.1.5.1(c) and III.13.2.5.2.5.1(b) of the Tariff to the extent necessary to permit Exelon to elect cost of service treatment at this time, and prior to FCA 13.

6. Waiver of Requirement to Submit Separate Section 205 Filing Regarding Capital Expenditures

The ISO is also requesting waiver of certain requirements of Section III.13.2.5.2.5.2 of the Tariff pertaining to any capital expenditures for a resource retained for reliability. If a retained resource must make capital improvements in order to continue to meet the reliability need for which it is retained by the ISO, and the supplier elects cost of service treatment, Section III.13.2.5.2.5.2 of the Tariff requires that the supplier submit the capital expenditures to the Commission in a section 205 filing separate from the supplier's cost of service filing. The capital expenditures filing must explain "why the capital expenditure is necessary in order to meet the reliability need identified by the ISO," and must demonstrate "that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO."[55]

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[55] Market Rule 1, Section III.13.2.5.2.5.2(b)

The ISO seeks waiver of this provision to permit Exelon to include in its section 205 cost of service filing for Mystic 8 & 9 any capital expenditures Exelon thinks may be necessary in accordance with Section 13.2.5.2.5.2. The ISO requests this waiver solely for the purpose of expedience due to the compressed time frame under which the ISO anticipates Exelon will ask the Commission to complete the Mystic 8 & 9 cost of service proceeding. Combining the two contemplated section 205 filings into a single case in this instance will afford interested parties the ability to address all cost of service matters relating to Mystic 8 & 9 in a single proceeding. This will promote the efficient resolution of the issues in accordance with the timetable Exelon requires. The ISO is not requesting waiver of the standard that Section III.13.2.5.2.5.2 requires a supplier to meet to qualify for recovery of its capital expenditures.

7. Waiver of Deadlines to Elect Unconditional Treatment to Permit Retirement in the Event Exelon's Cost-Of-Service Request is Not Approved by the Commission and to Address Reliability Retention Election

Under Section III.13.1.2.4.1 of the Tariff, the deadline for a supplier to elect whether to unconditionally retire must be made by the supplier within ten business days of receiving the IMM's determination regarding the Retirement De-List Bid, which is normally issued in mid-June of the year prior to the auction.[56] Accordingly, for FCA 13, a supplier (like Exelon) must elect conditional or unconditional treatment by July 6, 2018.

Separately, under Section III.13.1.2.3.1.5.1(d) of the Tariff, if the ISO determines that a resource under a Retirement De-List Bid is needed for reliability, the supplier has ten business days to decide whether to accept the ISO's request to retain the resource for

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56 Market Rule 1, Section III.13.1.2.4.1.

reliability, or whether instead to retire despite the reliability determination. For FCA 13, this election deadline is August 31, 2018.

Exelon has indicated that it will retire Mystic 8 & 9, and those units will not participate in FCA 13, unless it can obtain certainty prior to the auction regarding the cost of service the Commission will authorize for Mystic 8 & 9 for Capacity Commitment Periods 13 and 14. Since the election to retire unconditionally must be made by July 6, 2018, and the election of whether to accept a reliability retention request must be made by August 31, 2018, the ISO requests waiver, with respect to Mystic 8 & 9, and for FCA 13, of the indicated deadlines under Sections III.13.1.2.4.1 and III.13.1.2.3.1.5.1. More specifically, the ISO requests waiver of these terms to permit Exelon to notify the ISO whether it will agree to reliability retention or retire unconditionally the Mystic 8 & 9 units by the earlier of five business days after the Commission's order ruling on Exelon's cost-of-service for Mystic 8 & 9, including its Annual Fixed Revenue Requirement, or January 4, 2019. This deadline for Exelon's decisions will provide the ISO with sufficient time to enter, and confirm the accuracy of, all required data before FCA 13 is held on February 4, 2019.

D. The Proposed Waivers Are Consistent with Commission Precedent

The Commission evaluates requests for waiver of tariff provisions based on four well-established criteria:

(1) The request is made in good faith;

(2) The waiver is of limited scope;

(3) The waiver addresses a concrete problem; and

(4) The waiver would not have undesirable consequences, such as harm to third parties.[57]

The ISO's petition satisfies these criteria.

1. The ISO Has Acted in Good Faith

The ISO's request for waivers of selected portions of its Tariff as set forth in this petition satisfies the "good faith" criterion of the Commission's waiver standard. The ISO's proposed waivers are consistent with the ISO's longstanding concerns about the region's fuel security, concerns it has publicly stated on numerous occasions.[58] Indeed, the ISO undertook and published its Operational Fuel-Security Analysis for the specific purpose of highlighting the risks associated with the fuel security issues facing New England.

Consistent with the ISO's proposed waivers, the Operational Fuel-Security Analysis and Mystic Retirement Studies identify Mystic 8 & 9 and Distrigas as critical resources for fuel security. The loss of Mystic 8 & 9, with or without the concomitant retirement of Distrigas, would present serious risks for the reliability of the New England Electric System.[59]

The ISO supports reliance on market mechanisms to guide and enhance the efficiency of electric system operations. Nonetheless, the ISO cannot ignore the critical need for continued operation of Mystic 8 & 9 in the winter months in order to ensure fuel

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57 *Gateway Cogeneration 1, LLC*, 161 FERC ¶ 61,028, at P 14 (2017); *Consumers Energy Co.*, 150 FERC ¶ 61,125, at P 42; *DTE Electric Co.*, 150 FERC ¶ 61,127, at P 39.

58 *See supra* note 35.

59 Brandien Testimony at 45:11 – 47:9.

security and thus to maintain reliability. Therefore, the ISO must balance its obligation to ensure reliable electric service for the New England region with its reliance on market mechanisms, including the Forward Capacity Market. In this instance, the ISO has concluded—reasonably and in good faith—that ensuring reliable winter service outweighs its reluctance to utilize an out-of-market contract. Thus, the ISO has determined that, until fuel security issues in New England can be addressed through market mechanisms that promote a long-term solution, it must retain Mystic 8 & 9 for fuel security to provide reliable winter electric service in New England during the 2022-2024 duration of the proposed waivers.

2. The Waiver Is of Limited Scope

The ISO's requested waivers are limited in scope and therefore also satisfy the second prong of the Commission's waiver standard. The ISO seeks waivers of the Tariff solely with respect to Mystic 8 & 9, even though other units at Mystic Station are also retiring, because Mystic 8 & 9 provide critical fuel security for the New England grid. As explained above, Mystic 8 & 9 are needed to ensure reliability during winter operations. No similarly situated resources have submitted retirement bids to remove themselves from the market. Further, the Tariff already provides a mechanism by which Exelon may insist on a cost of service rate, as well as a form of RMR contract.[60] Thus, the proposed waivers are appropriately limited to modifying the Tariff's criteria for retaining retiring resources and the schedule for Exelon to elect conditional or unconditional retirement.

The proposed duration of the requested waivers also is limited, in order to minimize any adverse effects on New England's wholesale electricity markets. The ISO currently

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60 Market Rule 1, Section III, Appendix I.

plans to file a market-based proposal to address long-term fuel security in the second half of 2019. However, the three-year lead time of the Forward Capacity Market dictates that Exelon must decide now the conditions under which it is willing to continue operating Mystic 8 & 9 to provide fuel security in the absence of a market for that product. The requested waivers are as narrow as feasible, given Exelon's requirements of a two-year cost of service agreement and a determination on cost of service prior to the January 2019 deadline for it to decide whether to participate in FCA 13.

3. The Waivers Address a Concrete Problem

The ISO's requested waivers address a concrete problem. Given the fuel security issues in New England, the ISO has determined, based on its operational experience as well as the analyses Mr. Brandien presents in his testimony, that Mystic 8 & 9 are critical to maintaining reliability during the winters of 2022-2023 and 2023-2024.

Furthermore, the ISO must act now in order to ensure that Mystic 8 & 9 remain in service after Exelon's existing capacity commitments for the Mystic Station end on May 31, 2022. Exelon has made it clear that, if the requested Tariff waivers are granted and it is assured of a satisfactory cost of service for Mystic 8 & 9 on the timetable it requires, it will enter FCA 13 and will accept Capacity Supply Obligations for Mystic 8 & 9 for the duration of the 2022-2023 and 2023-2024 Capacity Commitment Periods.

Accordingly, granting the requested waivers will ensure that Mystic 8 & 9 remain in service until May 31, 2024, by which date the ISO expects to have fully implemented a long-term, market-based, fuel security solution. There is no other mechanism available to address the reliability risks associated with Exelon's proposed retirement of Mystic 8 & 9 in 2022.

4. The Waiver Does Not Have Undesirable Consequences

The final element of the Commission's waiver standard is whether the waiver will have "undesirable consequences, such as harming third parties."[61] The ISO appreciates that an RMR agreement, by allowing a generation facility to recover its costs regardless of the market price for capacity, raises the potential for market distortions. The Commission has approved RMR contracts despite its recognition that "RMR agreements suppress market clearing prices and deter investment in new generation."[62] For this reason, the Commission allows RTOs to enter RMR agreements "with only those units that are needed for reliability," and "the Commission expects that the agreements will be in effect only for the period during which the units are needed for reliability."[63] The Commission further has stated that RMR agreements "should be a last resort."[64] In other words, the Commission has recognized that RMR contracts are out-of-market arrangements and, therefore, any such agreement must be justified.[65]

For the reasons explained above, the ISO submits that an RMR contract is justified for Mystic 8 & 9. As Mr. Brandien's testimony demonstrates, retirement of Mystic 8 & 9

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[61] *DTE Electric Co.*, 150 FERC ¶ 61,127, at P 39; *see Gateway Cogeneration 1, LLC*, 161 FERC ¶ 61,028, at P 14.

[62] *Milford Power Co.*, 119 FERC ¶ 61,167, at P 31 (2007); *see Devon Power LLC*, 103 FERC ¶ 61,082, at P 29.

[63] *Devon Power LLC*, 103 FERC ¶ 61,082, at P 30.

[64] *Id.* at P 31; *see Milford Power Co.*, 119 FERC ¶ 61,167, at P 31.

[65] Of course, the requested waivers will not, of themselves, depress market prices. Any effect on prices will result from the cost of service rate Exelon will receive. Accordingly, comments on the effects of the cost of service contract for Mystic 8 & 9 should be considered in the separate docket in which Exelon will file that agreement.

may lead to periodic depletion of 10-minute operating reserves and load shedding.[66] Though the ISO and New England stakeholders are developing a market-based solution to the region's fuel security issues that will both price the winter energy constraints and provide the economic stimulus to retain and incent resources to provide sufficient firm energy during the winter, it is unlikely that the region will develop sufficient new infrastructure by 2022 to make up for the loss of Mystic 8 & 9. Under these circumstances, waiving the requested Tariff provisions to enable the ISO to enter an RMR agreement with Exelon is truly a last resort. Accordingly, under *Devon Power LLC* and *Milford Power Company*, the mere fact that RMR agreements may affect market prices is not a reason for denying the requested waivers.

Additionally, the Tariff already allows a generator to elect a cost-of-service rate when the ISO retains a resource to address a reliability issue. Accordingly, the proposed waivers the ISO requests do not, of themselves, entail any impacts not already contemplated by the Tariff. Instead, the waivers modify the trigger condition and the deadlines such that Exelon may obtain a cost-of-service determination prior to the time under the Tariff when it must decide whether to participate in FCA 13.

The Commission has often balanced competing considerations when applying the fourth prong of its standard for tariff waivers. For example, in both *DTE Electric Company* and *Consumers Energy Company*, the Commission considered proposed waivers of the Mid-Continent ISO's must-offer requirement and the requirement to purchase replacement capacity. In both cases, the Commission weighed the effect of the proposed waivers on

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66 *See* Brandien Testimony at 41:15 – 42:4, 46:1 – 47:9.

capacity revenues against the possible increase in costs to consumers.[67] Similarly, here, the Commission must weigh potential negative market consequences for some market participants against the potential that the ISO may be unable to meet demand in New England during the winters of 2022-2023 and 2023-2024. The ISO submits that maintaining reliability in New England during the coldest winter months outweighs the potential market impacts. That said, the ISO plans to address related capacity price formation issues with its stakeholders later this year.

IV. CONCLUSION

The ISO submits this petition reluctantly, because it hesitates to turn to out-of-market arrangements of any kind. However, the ISO has concluded that, in this instance, its responsibility to ensure the reliability of the New England electric grid is paramount. Retirement of Mystic 8 & 9 in 2022 presents unacceptable risks that the system will have inadequate supplies of electricity to serve all customers during the coldest days of New England's winters. Retaining Mystic 8 & 9 is necessary to prevent that risk from coming to fruition, and the ISO's proposed waivers of its Tariff are limited to those needed to address Exelon's unwillingness to take on further capacity commitments for Mystic 8

[67] *DTE Electric Co.*, 150 FERC ¶ 61,127, at P 45; *Consumers Energy Co.*, 150 FERC ¶ 61,125, at P 48.

& 9 at this time without certainty regarding its compensation. Therefore, the ISO respectfully requests that, on or before July 2, 2018, the Commission issue an order granting the waivers of the Tariff described in this petition, and making those waivers effective on July 2, 2018.

Respectfully submitted,

/s/_Maria A. Gulluni___

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May 1, 2018

Exhibit No. ISO-1

Testimony of Peter T. Brandien on Behalf of ISO New England Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) Docket No. ER18-____-000

TESTIMONY OF PETER T. BRANDIEN
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION AND SUMMARY OF TESTIMONY

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

A: My name is Peter T. Brandien. I am employed by ISO New England Inc. ("the ISO") as the Vice President of System Operations. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I have a Bachelor of Science degree in Electrical Engineering from the University of Hartford. I have more than 31 years of energy industry experience in control room operations. In 2004, I joined the ISO as the Vice President of System Operations. In that capacity, I am responsible for the day-to-day operations of New England's bulk electric system and oversight of transaction management, transmission technical studies, outage coordination, unit commitment, economic dispatch, system restoration, operator training, certain compliance functions and development of operating procedures. Prior to joining the ISO, I spent 17 years at Northeast Utilities, most recently as director of transmission operations. Before joining Northeast Utilities, I served in the U.S. Navy as a submarine nuclear propulsion plant operator/electrician.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony explains the need to retain Units 8 and 9 of Exelon Generation Company, LLC's ("Exelon's") Mystic Generating Station ("Mystic 8 & 9") as capacity resources for fuel security reasons. Mystic 8 & 9 are solely fueled by the liquefied natural gas ("LNG") import facility known as Distrigas.[1] In the first part of my testimony, I explain the New England region's acute fuel security challenges and the ISO's measurement of those challenges. Next, I explain the critical importance of Mystic 8 & 9 to maintaining system reliability from a fuel security perspective, particularly during winter operations. Finally, I describe the consequences the ISO foresees, should Mystic 8 & 9 be permitted to retire in 2022, and how those consequences would be compounded by the additional loss of Distrigas.

Q: PLEASE DESCRIBE THE MYSTIC 8 & 9 GENERATING FACILITIES, AND THEIR RELATION TO THE DISTRIGAS LNG IMPORT FACILITY.

A: Mystic 8 & 9 are part of Exelon's Mystic Generating Station, located in Everett, Massachusetts. The Mystic Generating Station is comprised of Mystic 7, 8 and 9, as well as the Mystic Jet, which together have generating capacity of 2,274 megaWatts ("MW"). Exelon has indicated that it will unconditionally retire Mystic 7 and the Mystic Jet[2] in the ISO's thirteenth Forward Capacity Auction ("FCA 13"), which is associated with Capacity Commitment Period 2022-2023 (June 1, 2022-May 31, 2023).

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[1] Distrigas is also known as the Everett Marine Terminal.

[2] Mystic 7 is a 560 MW, steam generating unit fueled by either oil or natural gas. Mystic Jet is an oil-fired combustion turbine with a capacity rating of approximately 14 MW.

Mystic 8 & 9 are combined-cycle, gas-fired generating units, each of which includes two gas-turbine generators and a single heat-recovery steam turbine generator. Mystic 8 & 9 have a nominal aggregate winter generation capacity of approximately 1,700 MW, and summer aggregate capacity of approximately 1,400 MW. Mystic 8 & 9 are fueled solely by regasified LNG delivered from the Distrigas LNG facility.

The Distrigas plant, which Exelon has announced it is acquiring from the present owner, ENGIE North America, is located adjacent to the Mystic Generating Station, also in Everett, Massachusetts. Distrigas has LNG storage capacity equivalent to 3.4 billion cubic feet ("Bcf") of natural gas, and includes equipment for the import, storage and regasification of LNG that is delivered to the facility by ship. In addition to being the sole fuel supply for Mystic 8 & 9, Distrigas has the capacity to make firm deliveries of up to 435 million cubic feet per day ("MMcf/d") to two of the five interstate natural gas pipelines transporting gas into New England from New York—namely, Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company— and the local gas utility's distribution system.

Exelon has stated that it is acquiring Distrigas for the purpose of ensuring that it can continue to fulfill the current Capacity Supply Obligations associated with Mystic Generating Station, which extend through May 31, 2022. As the sole source of fuel for Mystic 8 & 9 and its co-location with the generating facilities, Distrigas is an integrated part of Mystic 8 & 9, akin to an on-site oil tank.

Q: WHY ARE MYSTIC 8 & 9 IMPORTANT TO THE RELIABILITY OF THE NEW ENGLAND ELECTRIC GRID?

A: Mystic 8 & 9 are fueled exclusively by on-site LNG, in contrast to the general reliance of New England's natural gas-fired generation fleet on "as-available" fuel deliveries from the constrained regional natural gas pipelines. In other words, because Mystic 8 & 9 are large generating resources with on-site fuel that do not use or depend on the interstate natural gas pipeline system, they are important for regional fuel security and the ISO is taking steps to delay their retirement at this time. This testimony is offered in support of the ISO's request to the Commission to approve a means of keeping the plant operating for the reliability reasons that I will cover later in my testimony.

Q: CAN YOU PROVIDE AN OVERVIEW OF THE RELIABILITY IMPACTS TO THE SIX-STATE NEW ENGLAND REGION THAT WOULD RESULT FROM THE RETIREMENT OF MYSTIC 8 & 9?

A: The retirement of Mystic 8 & 9 presents an unacceptable fuel security risk to New England, particularly during the winter months. The loss of these resources further stresses the region's fuel supply infrastructure because Mystic 8 & 9 produce significant energy without reliance on the gas pipeline system, which is particularly constrained in the winter months. The ISO's analyses show that, without Mystic 8 & 9, in a cold winter similar to that experienced in 2014-2015, the ISO will have to resort to reductions in service during the 2022-2023 and 2023-2024 Capacity Commitment Periods, even under the most optimistic winter operating scenarios.

These reductions in service potential include load shedding (controlled outages or rolling blackouts around the New England region – not just in the Boston area). Should the retirement of Mystic 8 & 9 – Distrigas's largest customer – lead to the further loss of the Distrigas facility, the region's reliability issues will be compounded.

The ISO, as the Reliability Coordinator, Balancing Authority, and Transmission Operator registered with North American Electric Reliability Corporation ("NERC"), is responsible for complying with the NERC reliability standards associated with those responsibilities. In discharging those obligations, the ISO has determined that the risks presented by the proposed retirement of Mystic 8 & 9 are unacceptable, and thus proposes to retain Mystic 8 & 9 for the 2022-2024 period. I will describe later in my testimony the analyses on which the ISO bases this conclusion.

Q: WHAT IS THE FUEL SECURITY NEED WARRANTING THE RETENTION OF MYSTIC 8 & 9?

A: Fuel security refers to the assurance that power plants will have or be able to obtain the fuel they need to run. In other words, it refers to the role of generators' fuel arrangements, and the ability of infrastructure to deliver fuel in real-time in order to maintain system reliability. In New England, real-time system reliability is increasingly challenged by the possibility that the region's generating fleet will not have, or will not be able to obtain, the fuel necessary to produce sufficient energy to meet system demand and to maintain required operating reserves during extended periods of cold winter weather or other, similar system-stressed conditions (*e.g.*, an extended outage of certain facilities).

New England's fuel security challenges are exacerbated by the continuing industry trend of replacing coal-fired, oil-fired, and nuclear generation (*i.e.*, generation with on-site fuel) with natural gas-fired resources that rely on non-firm (as available) fuel supply arrangements. While renewable resources are also replacing coal-fired, oil-fired, and nuclear facilities, these resources are intermittent. Renewables can and do help to reduce natural gas demand on the winter-constrained pipeline system. However, they have not been developed on a scale and with sufficient operational capability (*e.g.*, ability to operate 24 hours a day at the needed and controllable levels) to address the region's fuel security issues to a material extent in the foreseeable future, and will not be able to do so within the 2022-24 timeframe discussed in this testimony.

The continuing trend of retirement of dispatchable, non-intermittent resources with on-site fuel creates increasing risks to reliable system operations, risks the ISO has most recently documented in its January 2018 Operational Fuel-Security Analysis ("OFSA")[3] and in its March 9, 2018 response to the Commission's Resilience Order in Docket No. AD18-7-000.[4] These risks are confirmed by further analyses the ISO has conducted since it received Exelon's retirement bids for the Mystic Generating Station.

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[3] *Operational Fuel-Security Analysis*, ISO New England Inc. (Jan. 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[4] *Response of ISO New England Inc.*, Docket No. AD18-7-000 (Mar. 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Resilience Order").

II. NEW ENGLAND'S FUEL SECURITY CHALLENGES

Q: PLEASE EXPLAIN THE FUEL SECURITY CHALLENGES IN NEW ENGLAND.

A: New England has been dealing with concerns related to fuel security since the January 2004 "Cold Snap," when the region experienced extremely low temperatures, sustained high winds, and particularly high demand for electricity concurrent with sustained high utilization of regional natural gas pipelines' capacity to meet heating demand. The 2004 Cold Snap prompted concerns about market and system performance during severe cold weather conditions because it exposed vulnerabilities of the New England power system. These vulnerabilities relate especially to the unavailability of gas transportation capacity for non-firm customers, like most gas-fired generators in New England, when the capacity of the natural gas-fuel infrastructure is fully utilized by firm shippers, primarily for service to residential and commercial space heating customers.

Since then, the ISO has implemented market design changes and enhanced operating procedures to try to address reliability concerns arising from the region's growing dependence on natural gas without corresponding increases in the region's interstate natural gas pipeline capacity. Nevertheless, New England's fuel security challenges have become more acute in recent years as the resource mix in the region's power system has continued to change. The shift in the region's generation fleet away from resources with on-site fuel to natural gas-fired generators that rely on as-available fuel delivery services (primarily capacity released by firm shippers) has exposed the limitations of New England's existing fuel infrastructure, and thus has further heightened the region's fuel-security risks. The reliability of New England's bulk electric system is increasingly challenged by the possibility that the region's generating fleet will not have on hand, or will not be able to obtain when needed, the fuel generators require to produce sufficient energy to meet system demand and to maintain required operating reserves, particularly during extended periods of winter weather or other system-stressed conditions. The role of generators' fuel arrangements in real-time system reliability is critical for any region, but it is particularly acute for New England's bulk electric system.

Q: WHY IS FUEL SECURITY MOST ACUTE IN NEW ENGLAND?

A: A reliable supply of electricity hinges on the generation fleet's ability to produce electricity to meet the demand for energy across all demand levels. Sufficient fuel supply to maintain reliability requires, in turn, a fuel-delivery system that has the 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 capacity and fuel actually stored on site, along with the ability to operate using the on-site fuel.

The New England electric system is especially reliant on fuel supply arrangements and infrastructure. New England does not have indigenous fossil fuel extraction or processing industries, and lacks large-scale fuel storage such as the large underground natural gas storage facilities found in other parts of the country. Therefore, the region's generating fleet primarily relies on fuels imported by ship, truck, pipeline or barge from elsewhere in the United States or from Canada or overseas. These factors give fuel procurement, transportation, and storage a more pivotal role in reliable power system operations in New England than in other regions.

New England's fuel procurement, transportation, and storage issues are most acute with respect to natural gas, on which the regional power system is increasingly dependent. New England's reliance on natural gas for electric generation has increased dramatically over the past decade; currently, natural gas-fired generators provide more than half of New England's energy annually. However, the capacity of the region's natural gas-fuel infrastructure has not expanded in proportion to the growth of power sector demand for gas fuel and transportation.

It is my understanding that New England's five interstate natural gas pipelines were designed and built to meet the peak demand needs of the entities that historically contracted for their capacity. Accordingly, most of the region's interstate pipeline capacity is contractually committed to provide firm transportation service to the local gas distribution utilities that serve retail and commercial gas consumers under a public utility obligation to meet those customers' full requirements – for space heating in particular – under all conditions.

Natural gas-fired power plants in New England typically have not contracted for expansions of interstate pipeline capacity in order to obtain firm transportation of their fuel supplies. Instead, most of them 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—the local gas distribution utilities—do not need the capacity to meet their customers' requirements. During most months of the year, the pipelines' existing capacity is sufficient for both the local gas distribution utilities and the natural gas-fired power plants. However, it is increasingly challenging for them to meet all of the region's demand for gas during the coldest weeks of the year. As a result, when firm shippers' demands are greatest – typically during cold weather because of peak use of gas for space heating – pipeline capacity often is unavailable for all the natural gas-fired generators that need to run.

Q: IS THERE A SHORTAGE OF INSTALLED GENERATING CAPACITY IN NEW ENGLAND?

A: No, fuel security is not an issue of installed generating capacity. This is not about the 1 in 10 day standard for loss of load and the process for determining the amount of installed capacity the region requires to meet peak load conditions. Fuel security instead is a matter of the ability of those power plants whose capability is procured in a capacity market to obtain and use the fuel they need to produce *energy* to meet demand and maintain required operating reserves, even at load levels that are far below the summer peak energy needs. Said another way, this is an *energy* problem, not a *capacity* problem. This problem is most acute during winter, particularly during periods of sustained cold weather. However, it also is a concern in the event that the New England interstate natural gas pipeline system becomes constrained during summer peaks, when dual-fuel and oil-fired plants are restricted or even prohibited from running on oil due to emissions limitations imposed to maintain air quality.

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 for those generators to actually operate, only some portion of that capacity will actually be able to produce energy. Thus, a region may have sufficient installed capacity, but may not have sufficient fuel to produce electric energy from that installed capacity.

Q: WHY IS THE ISO'S CONCERN ABOUT FUEL SECURITY GROWING DESPITE HAVING SUFFICIENT RESOURCES TO MEET THE REGION'S CAPACITY REQUIREMENT?

A: A number of factors in combination continue to highlight fuel security as an important issue for the ISO and the regional electric system. These factors include the continued growth of local gas distribution companies' gas demand, retirement of existing resources with on-site fuel storage (such as both the Vermont Yankee (615 MW) and Pilgrim (683 MW) nuclear facilities, the large Brayton Point Station (1,528 MW), Salem Harbor (747 MW), and several others in recent years), and the replacement of these resources with new, combined cycle natural gas-fired generating facilities, most of which are without comparable on-site fuel storage, do not have firm gas fuel arrangements, and cannot get fuel during periods when the constrained natural gas pipeline system is being fully utilized by other customers.

New combined cycle natural gas-fired generating facilities have made up a substantial portion of the new resources that have cleared in the Forward Capacity Market. As I discussed earlier, the region's growing reliance on natural gas-fired generation—without a commensurate increase in the capacity of the pipelines that supply natural gas to New England—means that an increasing amount of the region's generating fleet competes for the same limited amount of as-available, secondary gas pipeline capacity. Thus, a growing portion of the New England generating capacity presents a risk that it will be unable to run due to lack of fuel when it is needed during extended periods of cold weather or other periods of high demand on the region's pipelines. New England's lack of natural gas storage narrows the range of options available to address this problem.

In addition, as a result of economic and 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. Such retirements both reflect and exacerbate the region's dependence on natural gas-fired generation. Over 4,600 MW – an amount equal to about 16 percent of the region's current generating capacity – of non-gas-fired power plants will have retired by 2021,[5] and another 5,400 MW of coal- and oil-fired generation are at risk for retirement or are retiring in the coming years, including Mystic 7, a 560 MW unit, which Exelon has indicated it will retire May 31, 2022.

Renewable resources, including wind, solar, energy efficiency, and energy storage, are rapidly expanding on the New England power system. Significant increases in these resources, which are correspondingly replacing retiring resources, help reduce the demand on the existing natural gas fuel supply infrastructure. However, the time horizon for the region to transition away from fossil fuels sufficiently to relieve the present fuel-security problem is a number of years into the future, well past the time

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5 These retirements include coal- and oil-fired generators (Salem Harbor, Norwalk Harbor, Brayton Point, Mount Tom, Bridgeport Harbor 3), nuclear facilities (Vermont Yankee and Pilgrim), and some smaller generators.

period being discussed here, and its timing is too uncertain to remove the clearly foreseeable, and much nearer-term, need to retain Mystic 8 & 9.

In sum, the region's steady shift away from generators with on-site fuel to natural gas-fired generators relying on non-firm fuel delivery service, and to inherently intermittent resources, in the case of wind and solar, has steadily increased the operational risks for the electric grid. The limitations of the region's existing fuel supply infrastructure became quite evident again during the cold weather conditions experienced in New England during the last week of December 2017 and the first week of January 2018 (the "2017-2018 Cold Spell").

Q: PLEASE DESCRIBE OPERATIONS DURING THE 2017-2018 COLD SPELL.

A: During the 2017-2018 Cold Spell, average temperatures in all major cities in New England were below normal for at least 13 consecutive days, of which 10 days averaged 10ºF below normal. Heating demand for gas utilized essentially all of the capacity of the region's natural gas-fuel infrastructure, which resulted in substantially higher spot market prices for natural gas, and concomitantly higher wholesale electricity prices. This led, in turn, to the ISO's dispatch of oil- and coal-fired generation plants, as they became more economical than gas. During the cold spell, oil- and coal-fired resources contributed a full one-third of all electricity generated in New England, while in the preceding year such resources had provided just two percent (yearly average) of New England's electricity. On the other hand, natural gas-fired generators, which generated almost half of the region's electricity prior to the cold spell, were able to supply just 24 percent of total electricity produced during the cold spell. With oil-fired generation operating for extended periods at or near capacity, oil inventories at power plants around the region, as well as those plants' emissions allowances, depleted rapidly over the two-week duration of the cold spell. This, along with declining LNG quantities in storage, made electric system operations extremely challenging, and significantly increased the reliability risk to the system. This experience highlights the point that fuel security risk is not an issue that affects a few hours of operations like a peak in demand. Instead, it is a condition that becomes steadily worse as the remaining generation resources with on-site fuel deplete their fuel stockpiles.

Q: IS REPLENISHMENT OF ON-SITE FUEL PROBLEMATIC?

A: Yes. The flip side of on-site fuel is that replenishment of fuel inventory (LNG or oil) is not automatic. It can take considerable time to arrange for the commodity, transportation (by ship, barge, truck, or pipeline), and then delivery (offload). When fuel and transportation can be arranged by generators, these logistics can be hindered during the winter due to the types of fuel arrangements, availability at terminals, weather conditions affecting transportation, including icing of waterways, and the availability of trucks or barges, which may be committed to transporting home heating oil. For example, a large number of tanker-truck trips are required to resupply an oil-fired generating station, but the need for re-supply depends almost entirely on the weather, making it hard to predict in advance. Therefore, when a large oil-fired generating station is called on to produce electricity for an extended time, even if the operator could arrange for such a large trucking operation on short notice, the plant will burn the fuel as fast as it is delivered, or even faster.

Q: YOU MENTIONED THAT OIL BECAME MORE ECONOMICAL THAN GAS DURING THE 2017-2018 COLD SPELL. WAS THERE A LACK OF GAS-FIRED CAPABILITY OR WAS OIL SIMPLY MORE ECONOMICAL?

A: This is not just an economic issue for the region. It is a problem of the physical limits of the current natural gas pipeline system. The price of gas versus oil shows the relative scarceness of the commodity for non-firm users of the natural gas pipeline system. Some non-dual fuel gas generators may be able to get natural gas, but it is at very high prices. When power demand is very high, the region needs to pay those high prices and that is reflected in wholesale energy market prices during constrained winter conditions. But due to the physical limitations of the natural gas pipeline system, only so much gas can be delivered to generators in real time and, due to the difficulty of predicting the release of local distribution company ("LDC") capacity under extreme cold conditions, the amount of transportation available for gas-fired generation becomes extremely difficult to predict and the price of gas becomes very volatile. Generator commitment decisions have to be made the day before real-time operations. During the 2017-2018 Cold Spell and similar winter periods, a significant number of generators either could not get sufficient natural gas to commit to operate day-ahead, or were priced out of the market.

Q: HAS THE ISO TAKEN ACTION TO ADDRESS FUEL SECURITY RISKS?

A: Yes, the ISO has undertaken numerous efforts, in the form of market design changes and operating procedures, systems, and tools, to help mitigate the region's fuel-security challenges.

Q: WHAT MARKET DESIGN CHANGES HAS THE ISO UNDERTAKEN TO ADDRESS FUEL SECURITY RISKS?

A: The ISO has undertaken market rule changes to increase market efficiency, to create incentives for resources to perform when needed, and to improve gas-electric coordination. For example, in the Energy Market, the ISO revised the timing of the Day-Ahead Energy Market and Reserve Adequacy Analysis schedules to allow for bidding to end earlier, and for the ISO to commit resources earlier, than under the previous configuration.[6] These changes better align the electricity and natural gas markets to give generators more time to procure the natural gas they need to run the following operating day. The ISO also enhanced the flexibility of energy market offers to allow Market Participants to update their offers in real-time to reflect changing fuel costs.[7] These changes improve market pricing and generators' incentives to perform.

The ISO also implemented market rule changes to increase the amount of 10-minute operating reserve capability that is procured in advance through the Forward Reserve Market.[8] These changes help support the availability and deliverability of reserves to meet the increased real-time reserve requirements. The ISO also implemented market rules to improve the performance incentives associated with the Forward Reserve Market.[9] It further modified generator resource auditing requirements and procedures to provide the ISO with a more accurate assessment of the 10- and 30-minute operating

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[6] *See ISO New England Inc.*, 143 FERC ¶ 61,065 (2013).

[7] *See ISO New England Inc.*, 147 FERC ¶ 61,073 (2014).

[8] *See ISO New England Inc.*, Letter Order, Docket No. ER13-465-000 (Feb. 8, 2013).

[9] *See ISO New England Inc.*, Letter Order, Docket No. ER13-1733-000 (Aug. 15, 2013).

reserve capability of reserve resources.[10]

Q: WHAT OPERATIONAL MEASURES HAS THE ISO IMPLEMENTED TO ADDRESS FUEL SECURITY RISKS?

A: On the operations side, the ISO has developed Operating Procedures, systems and tools to improve coordination, communications, intelligence, and operations during cold weather conditions. For example, the ISO developed new Operating Procedures designed to improve information on generator availability during cold weather conditions. These procedures ask generators to report their anticipated availability to the ISO, including details on their ability to procure fuel, maintain oil inventories, and any physical limitations of their generating units. The ISO 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.

Additionally, the ISO developed decision-support tools for system operators. For example, our Gas Usage Tool allows the ISO 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 users and local gas distribution utilities' customers, as well as natural gas-fired generators, compared to the capability of the natural gas pipeline system, including LNG injections into the regional gas-fuel infrastructure. The tool does not produce a perfect forecast of gas availability for gas-fired generators, but it does provide useful insight (within practical limits) to the ISO's system operators when they make day-ahead unit commitment decisions. Under

[10] *See ISO New England Inc.*, 142 FERC ¶ 61,024 (2013).

extreme cold conditions, if there is doubt as to the availability of pipeline gas, operators are forced to err on the side of caution and rely more heavily on generators that use other fuels, including LNG.

These measures have helped the ISO maintain overall situational awareness and manage operational situations where fuel delivery to the region has become constrained. For example, the ISO, among other measures, initiated twice-weekly fuel surveys of oil-fired generation, and increased the periodicity to daily based on system conditions during and after the 2017-2018 Cold Spell to increase situational awareness. The ISO continuously monitored oil inventories and communicated with Market Participants to determine if their respective replenishment plans would get us through the cold weather. The ISO continuously assessed whether oil-fired units would run out of fuel before the cold weather diminished. Based on the information gained from these assessments, the ISO was able to depart from economics, which may have run oil units before available gas units, and adjusted the dispatch to bring on additional natural gas-fired generators for the days gas was available to such facilities in order to conserve oil and prevent certain oil-only units from running out of oil. These so-called generating unit "posturing" practices ultimately enabled the region to get through the cold stretch.

Q: HAS THE ISO ASSESSED THE IMPACTS OF FUEL-SECURITY CHALLENGES IN THE REGION?

A: Yes. In 2016, the ISO launched the OFSA to quantify the potential operational impacts the fuel-security challenges may pose in the near future. The OFSA had two key objectives: first, to understand the levels of fuel-security risks to reliability that the ISO 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 the ISO and stakeholders determine what steps New England should pursue to mitigate the risks.

Q: PLEASE DESCRIBE THE OPERATIONAL FUEL-SECURITY ANALYSIS.

A: The OFSA is a deterministic analysis designed to identify the season-wide operational impacts of various scenarios by not just looking at a single forecast winter peak day, but by examining the potential impacts to the reliable supply of energy (as opposed to capacity needs) over an entire 90-day winter season (December, January, February). Specifically, the analysis examined the effect of 23 possible future resource and fuel-mix scenarios, 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 and maintain power system reliability under a wide range of potential conditions, assuming no additional build-out of natural gas pipeline infrastructure would occur within the study timeframe. The analysis used the five resource variables most affected by market and policy responses as the key factors in the reliability of a future power system that must operate within the given fuel infrastructure constraints. Those variables are: additional 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.

For each scenario, the study quantified the fuel-security risk throughout the 90-day winter of 2024-2025 in terms of operational metrics by calculating the frequency and duration of energy shortfalls (events during which there is insufficient fuel to generate sufficient electricity to meet system demand) created by fuel supply limitations. Such shortfalls, in turn, require the ISO to employ actions in its Operating Procedures, including emergency actions, up to and including load shedding (or rolling blackouts). New England's actual winter 2014-2015 electricity demand (as adjusted to reflect the ISO's forecast for slightly higher net 90/10 peak load forecast for the winter of 2024-2025) served as a baseline. The 90/10 load forecast reflects only a ten percent chance of being exceeded due to weather.

The ISO used the 2014-2015 winter because, while that winter did not include the coldest days recorded in the past ten years, it had the most sustained consecutive cold days as measured by heating-degree days. This provided a wider perspective on the cumulative use of oil and LNG inventories over the 90-day winter period, and the need to replenish those inventories as cold weather persists. If the region experienced a colder winter than 2014-2015, as is possible, the number and duration of energy shortfalls the region would face would exceed those found in the OFSA.

The ISO chose to analyze winter 2024-2025 in the OFSA because the outlook for power system reliability in that timeframe is uncertain, largely due to expected retirements of non-gas-fired power plants, and the intervening years give the region time to act. The ISO recognized that actual conditions could change earlier or later.

III. NEED FOR MYSTIC 8 & 9

Q: WHAT SCENARIOS EXAMINED IN THE OFSA INDICATE THE IMPORTANCE OF MYSTIC 8 & 9 TO MAINTAINING RELIABLE ELECTRIC SERVICE FOR NEW ENGLAND?

A: The OFSA addressed 23 resource and fuel-mix combinations and assessed the effects of sustained outages of various key facilities. This wide range of scenarios was used in order to illustrate the array of potential risks that could confront the New England power system, given fuel security concerns during winter.

Of particular importance to this case, the OFSA assessed the effects on the reliability of the power system of, among other key energy facilities, a sustained disruption of the Distrigas facility during the 2024-2025 winter (December, January, and February) that would eliminate all the regasified LNG that provides the only fuel for the 1,700 MW Mystic 8 & 9 generators, as well as the gas that Distrigas can inject into the Algonquin and Tennessee interstate pipeline systems and the local gas utility's distribution system.

The OFSA thus examined the effects of a winter-long outage of the Distrigas facility and the concomitant loss of Mystic 8 & 9 (due to lack of fuel) in 2024-2025. Though its purpose was different, the relevance of OFSA's evaluation of this scenario to the ISO's present waiver petition is self-evident. The OFSA in this respect illustrates the effects on reliability of the winter-long absence of Mystic 8 & 9 in 2024-2025, just as though the generators were unavailable because of retirement, rather than due to an extended outage, as posited for purposes of the OFSA.

Q: HOW WERE THE OPERATIONAL IMPACTS OF FUEL SECURITY RISKS MEASURED IN THE OFSA?

A: The operational impacts were measured in the hours the ISO would have to invoke emergency Operating Procedures to maintain system reliability when not enough fuel was available to generate all the electricity needed to meet forecasted electricity demand and operating reserve requirements. More specifically, for each scenario, the study quantified the magnitude and frequency of energy shortfalls that would require the ISO to use its emergency Operating Procedures to serve aggregate system demand while maintaining the required levels of operating reserves.

When insufficient energy is available to meet total expected electricity demand while maintaining sufficient operating reserves to meet mandatory reliability requirements, the ISO follows its Operating Procedure No.4, Actions During a Capacity Deficiency ("OP-4"),[11] and Operating Procedure No. 7, Action in an Emergency ("OP-7").[12] OP-4 is used to maintain supply and demand in balance, to avoid violating 10-minute operating reserve requirements, and to avert the need to implement load shedding. It 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. Notably, with the implementation of OP-4, Action 1, the ISO begins to allow the depletion of 30-minute operating reserves, and, with the implementation of Action 5,

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[11] *ISO New England Operating Procedure No. 4 - Actions During a Capacity Deficiency*, ISO New England Inc. (July 5, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[12] *ISO New England Operating Procure No. 7Action in an Emergency (OP-7)*, ISO New England Inc. (Jan. 8, 2018), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

the analysis assumed 500 MW of emergency energy would be available to import over the external transmission ties. Actions 6 through 11 are emergency actions that may be more obvious to the public, such as voltage reductions and urgent public appeals for conservation.

In the analysis, if OP-4 actions were insufficient, the ISO started to deplete 10-minute operating reserves, which is a significant step because it leaves the system vulnerable to being unable to respond to a generator tripping offline, which could lead to damage to power system equipment and potentially could spread to other regions. OP-7 is the procedure the ISO follows to implement load shedding after the ISO starts depleting 10-minute operating reserves to maintain system balance. These procedures are designed to maintain the integrity of the larger bulk electric system. The order and speed at which the actions under these procedures would be implemented depends on the circumstances presented. For example, the ISO can bypass other steps and move immediately to load shedding if necessary to preserve the reliability of the bulk electric system.

In the OFSA, as the system stress intensified in each scenario, the study model progressed, in sequential order, through the series of actions under these 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 then to the full depletion of 10-minute operating reserves, before finally resorting to load shedding. The OFSA reports the number of hours and days when each action under OP-4, depletion of 10-minute operating reserves, and then finally OP-7 would be used, as well as the quantity of load affected in each instance, under each of the studied scenarios.

Q: WHAT WERE THE OPERATING RESERVES REQUIREMENTS ASSUMED IN THE OFSA?

A: NERC, the Northeast Power Coordinating Council ("NPCC"), and the ISO all have established requirements for maintaining operating reserve levels. For example, under NERC's BAL-002, "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," the ISO, as a Balancing Authority, is required to maintain Contingency Reserves in the amount of the largest single source contingency on the system, i.e., the system's largest generator or largest-capacity transmission line importing energy.[13] This requirement is to ensure that the ISO will be able to restore the Area Control Error ("ACE") (*i.e.*, the instantaneous difference between the transfer of electric energy between two Control Areas, accounting for the effects of frequency bias and correction for meter error) to specifically defined values (zero or pre-contingency values) within 15 minutes of the contingency loss. NPCC Regional Reliability Reference Directory #5, "Reserve," builds upon NERC's BAL-002 standard to require the ISO to have and, if deficient, to restore 10-minute operating reserves at least equal to its first contingency source loss.

The reserve requirements established by NERC, NPCC, and the ISO are incorporated in

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13 *BAL-002-2(i) – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event*, North American Reliability Corporation, https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=BAL-002-2(i)&title=Disturbance%20Control%20Standard%20%E2%80%93%20Contingency%20Reserve%20for%20Recovery%20from%20a%20Balancing%20Contingency%20Event&jurisdiction=United%20States (last visited May 1, 2018).

the ISO's Operating Procedure No. 8, Operating Reserve and Regulation ("OP-8").[14] To comply with those requirements, the ISO must maintain 10-minute operating reserves to recover from the loss of the largest source of power on the system, whether it is a large generator or transmission line importing power, and 30-minute reserves equivalent to 50 percent of the second-largest source of supply, in order to help the system replenish the loss of 10-minute reserves. The OFSA scenarios assumed an operating reserves requirement of 2,300 MW.

Q: WHAT DID THE OFSA SHOW REGARDING THE EFFECTS ON RELIABILITY IF MYSTIC 8 & 9 WERE UNAVAILABLE DURING THE 2024-2025 WINTER?

A: The OFSA assessed the impacts of the winter-long outage of the key energy facilities on the New England power system as represented in a Reference Case, as well as in a Combination Case, which included maximum potential retirements of existing resources and potential maximum additions of renewable resources. The Reference Case assumed the following key variables: retirements of 1,500 MW of coal- and oil-fired generators in addition to already scheduled retirements; 2,500 MW of imported power based on historical imports during winter months; a maximum daily combined injection of 1 Bcf/d of regasified LNG from Distrigas, the Canaport import, storage, and regasification facility in New Brunswick ("Canaport"), and the Northeast Gateway Deepwater Port buoy off Gloucester, Massachusetts (the "offshore buoy"); existing dual-fuel generating capacity with oil tank inventories filled twice during the 90-day winter; and 6,600 MW

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[14] *ISO New England Operating Procedure No. 8, Operating Reserve and Regulation*, ISO New England Inc. (Sept. 21, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

(nameplate) of renewable resources. The Combination Case reflected the same assumptions, except the assumed retirements were increased to 5,400 MW; the imports were increased to 3,500 MW; and the renewable resources were increased to 9,500 MW.

On a system represented by the Reference Case, the absence of Distrigas and Mystic 8 & 9 would result in 24 cumulative hours of load shedding over seven days (20,496 MWh of unserved load). Under the Combination Case, there would be twice as many (49) hours of load shedding over 11 days if the facilities were unavailable (49,805 MWh of unserved load).

Q: WHAT IS THE ROLE OF MYSTIC 8 & 9 IN MEETING THE REGION'S ENERGY NEEDS DURING WINTER OPERATIONS AND OTHER SYSTEM STRESSED CONDITIONS?

A: As briefly described earlier, Mystic 8 & 9 are natural gas-fired combined cycle units with total winter generating capacity of 1,700 MWs. While Mystic 8 & 9 are natural gas-fired, they are not fueled by or reliant on the interstate natural gas pipeline system. Rather, Distrigas serves as the equivalent of their on-site oil tank or coal pile. As a result, the ability of Mystic 8 & 9 to produce energy is not affected by capacity constraints on the regional natural gas pipeline systems. Further, while the absence of Mystic 8 & 9 by itself presents unacceptable reliability impacts to the region, the fuel supply for Mystic 8 & 9, Distrigas, has the additional capability to inject regasified LNG into the Algonquin and Tennessee interstate natural gas pipeline systems and the local gas utility's distribution system. It is my understanding that such injections of LNG on high demand days assist the gas pipeline operators in maintaining pipeline pressures, which, in turn, provide them with more operating flexibility to meet short-duration peaks and otherwise to accommodate variations in shippers' requirements. There are, however, physical limitations on what Distrigas can inject into the natural gas pipeline systems; the fuel supplying Mystic 8 & 9 cannot be fully redirected to the pipelines. Thus, while the loss of Mystic 8 & 9 constitutes an unacceptable reliability impact to the region's power system, the loss of the sole fuel source serving Mystic 8 & 9 further exacerbates an already bad situation.

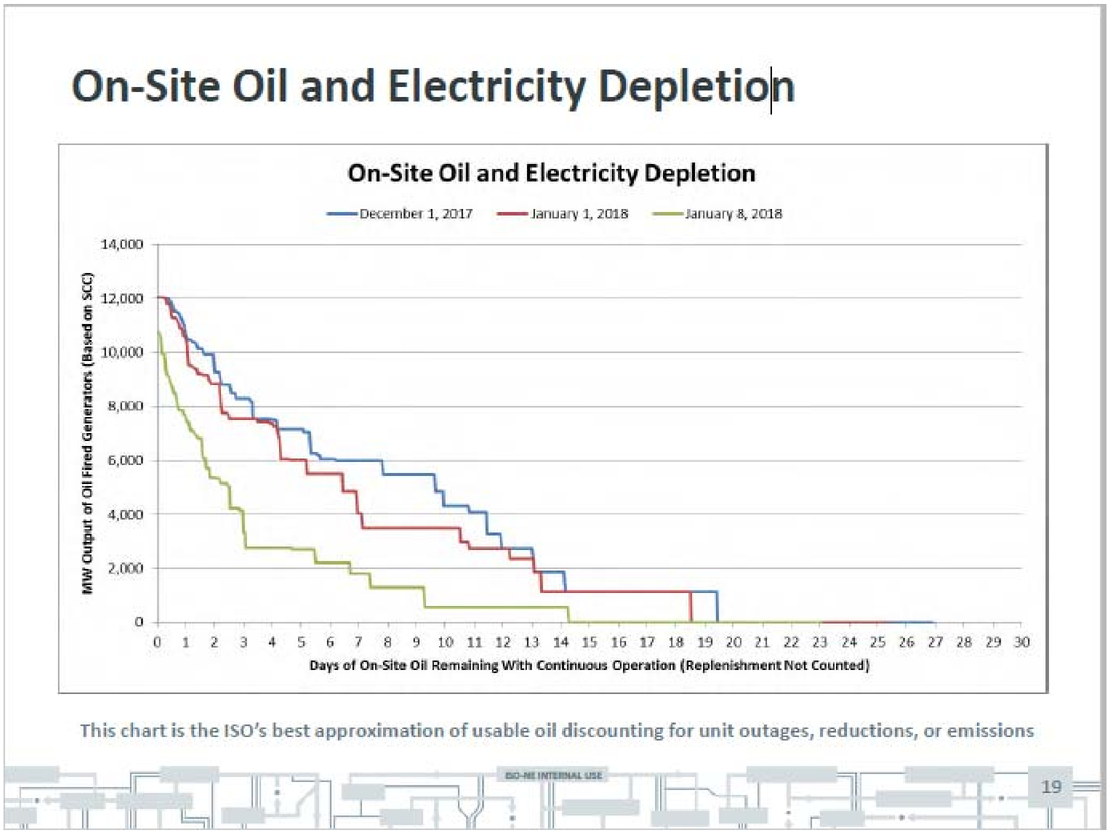
Q: WHAT WAS THE CONTRIBUTION OF MYSTIC 8 & 9 DURING THE MOST RECENT WINTER AND WAS IT CRITICAL TO THE REGION'S POWER SYSTEM?

A: The contribution of Mystic 8 & 9 during the 2017-2018 Cold Spell was crucial. During that cold weather stretch, New England generators burned two million barrels (84 million gallons) of oil, twice as much as the oil used by New England's power plants during the entire year of 2016. The electricity produced by Mystic 8 & 9 during the two-week period was the equivalent of <u>more than 360,000 barrels of oil</u>.

As we neared the end of the cold weather stretch, around January 8 and 9, the ISO avoided implementation of significant emergency operating procedures because, fortunately, the weather broke and temperatures climbed to above average, which allowed gas-fired generation to obtain fuel. Without that shift to gas-fired units, and even with Mystic 8 & 9, <u>available oil inventories were nearly depleted</u>, as illustrated in the slides reflected in Figures 1 to 3, below, from the ISO's Presentation to the NEPOOL Participants Committee, *Cold Weather Operations, December 24, 2017 –*

January 8, 2018:[15]

Figure 1



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15 Vamsi Chadalavada, *Cold Weather Operations*, ISO New England Inc., 23 (Jan. 16, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf.

Figure 2

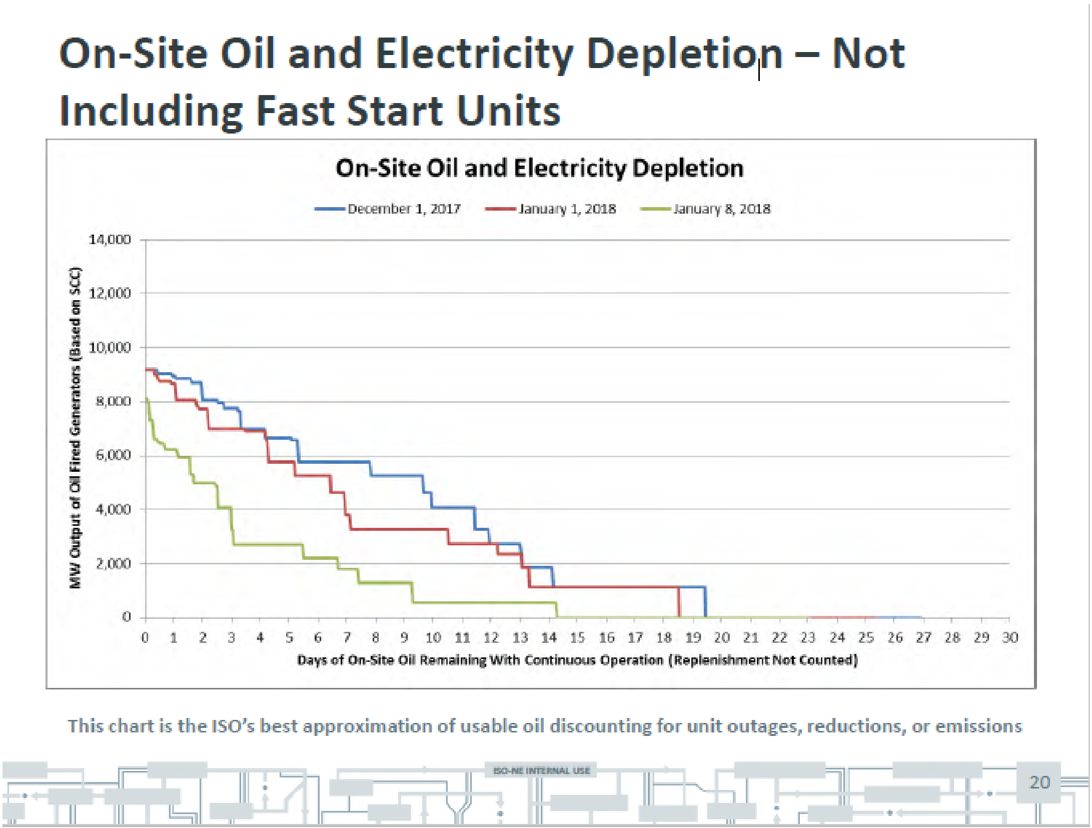
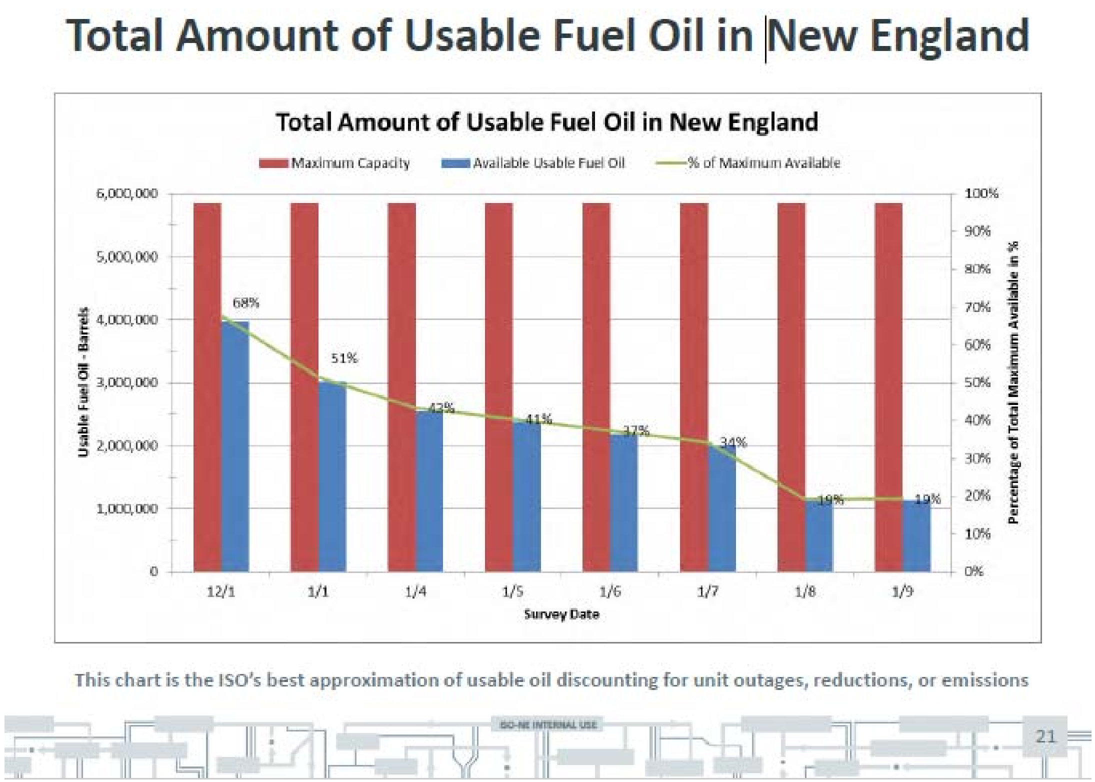

On-Site Oil and Electricity Depletion – Not Including Fast Start Units
On-Site Oil and Electricity Depletion
December 1, 2017
January 1, 2018
January 8, 2018
MW Output of Oil Fired Generators (Based on SCC)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Days of On-Site Oil Remaining With Continuous Operation (Replenishment Not Counted)
This chart is the ISO's best approximation of usable oil discounting for unit outages, reductions, or emissions
ISO-NE INTERNAL USE
20

Figure 3



Had Mystic 8 & 9 not displaced the burning of 360,000 barrels of oil, we would have been in a significantly worse situation in early January, 2018. This is not speculation or forecasted impacts; these are real operating conditions that the region has already lived through. Simply put, the contribution of Mystic 8 & 9 with their on-site fuel supply was objectively and indisputably critical this last winter, and is critical going forward.

Q: HAS THE ISO ANALYZED THE EFFECTS ON RELIABILITY IF MYSTIC 8 & 9 RETIRED IN 2022?

A: While the OFSA generally supports the continuing need for Mystic 8 & 9 in the winter of 2024-2025 to maintain reliability, the ISO also has conducted a 90-day winter energy analysis similar to that performed in the OFSA to assess implications to system operations if Mystic 8 & 9 were retired or otherwise lost earlier than the 2024-

2025 winter.

Specifically, using the same model developed for the OFSA, the ISO assessed the operational impacts of retirement of Mystic 8 & 9 across a range of scenarios on a power system representative of conditions similar to those assumed in the OFSA's Reference Case. The ISO evaluated the impacts of the Mystic 8 & 9 retirements during the winters of 2022-2023 and 2023-2024 with low LNG injection levels, assuming Distrigas ceases operating as a result of the retirements. I refer to these scenarios as the "Mystic and Distrigas Retirement Scenarios." Using the same model, the ISO also examined the operational impacts of the retirements with higher LNG injection levels, assuming Distrigas remains in operation. I refer to these scenarios as the "Mystic Retirement Only Scenarios." Additionally, the ISO assessed the operational impacts of the Mystic 8 & 9 retirements with higher LNG injections against certain resource outage/reduction contingencies. I refer to these scenarios as the "Mystic Retirement and Contingency Scenarios."

Q: HOW DO THE ASSUMPTIONS USED TO SIMULATE WINTER SYSTEM OPERATIONS IN 2022-2023 AND 2023-2024 DIFFER FROM THOSE USED IN THE OFSA'S REFERENCE CASE?

A: The underlying model used to simulate system operations during the 2022-2023 winter (December 2022 through February 2023) and 2023-2024 winter (December 2023 through February 2024) is the same as that used in the OFSA Reference Case, except that certain model inputs were adjusted for the two relevant winter periods. First, I address the model input assumptions that remain constant across all scenarios relative to each winter period.

Next, I describe the input assumptions that varied in the scenarios relative to each winter period to assess system response.

The following model inputs were adjusted and remained fixed across all scenarios relative to each winter period:

- Electricity Demand: All scenarios use the 2014-2015 90-day winter electricity demand, as adjusted to reflect the ISO's 90/10 peak load forecast, net of projected Energy Efficiency, based on the ISO's latest Capacity, Energy, Loads, and Transmission Report (which, for these analyses, was the recently released draft for 2018-2027 (the "Draft 2018 CELT Report")) for each of the respective winter periods. The winter 2022-2023 scenarios used 20,342 MW (net peak load), and the winter 2023-2024 scenarios used 20,205 MW (net peak load). These are lower load forecasts than were used in the OFSA.

- Natural Gas Demand: For both winter periods, local gas utility companies' gas demand was updated based on the 2016 study conducted by ICF International, Inc. for the ISO, which concluded that the annual demand for natural gas from the local gas utilities would rise at an average of about 2 percent per year, up to 591 Bcf/yr in 2025.[16] Like the OFSA, the analyses performed to assess the operational impacts of the Mystic 8 & 9 retirements assume local gas utilities' demand would be satisfied first, and the remaining natural gas pipeline capacity or LNG injections would be utilized for electricity generation.

- Operating Reserve Requirements: For both winter periods, the total operating reserves requirements were reduced from 2,300 MW to 2,100, with 10-minute operating reserve requirements reduced from 1,600 MW to 1,400 MW. The reason for this adjustment is that Mystic 8 & 9 is equivalent to the system's largest resource and, therefore, with the modeled retirement of Mystic 8 & 9, the system reserve requirement would be reduced during the winter period.

- Renewables: For winter 2022-2023, the scenarios assume 6,600 MW of renewables, including on- and off-shore wind, PV (both behind-the-meter and commercial), and other renewables (*e.g.*, biomass, refuse) based on the Draft 2018 CELT Report. This is the same amount assumed in the OFSA's Reference Case. For winter 2023-2024, the scenarios assume 6,900 MW based on the Draft 2018 CELT Report.

- Retirements: The scenarios did not model the additional retirement of 1,500 MW of

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[16] *New England LDC Gas Demand Forecast Through 2030*, ICF International, Inc., 10 (Oct. 3, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/iso-neldc-demand-forecast-03-oct-2016.pdf.

coal- and oil-fired generation assumed in the OFSA's Reference Case. Instead, the models used for the 2022-2023 and 2023-2024 winter periods assume the 1,500 MW of coal- and oil-fired generation are available. As in the OFSA's Reference Case, the coal-fired, oil-fired, and nuclear power plants that are scheduled to be retired by June 2021 are retired from the system (*i.e.*, Pilgrim Nuclear Station (683 MW), which is scheduled to retire in June 2019, and Bridgeport Harbor 3 (385 MW), which is scheduled to retire in June 2021). The scenarios also model the retirement of the Mystic Generating Station (all units).

As I noted earlier, when we look at this last winter – not even having to look ahead to 2022 or 2023 –Mystic 8 & 9's contributions were clearly critical for system reliability.

The only model input assumptions that varied in the scenarios relative to each of the winter periods are: the amount of LNG injections; the amount of energy imports across the external ties; and, the frequency of refilling dual-fuel oil tanks. Specifically:

- LNG Injections: For each winter period, the scenarios considered low LNG injection levels of 0.8 to 0.9 Bcf/d from Canaport and the offshore buoy, assuming Distrigas ceases operating with the Mystic 8 & 9 retirements, and higher LNG injection levels of 1.0 Bcf/d to 1.2 Bcf/d with Distrigas assumed to remain in service, along with Canaport and the offshore buoy. The analyses assume a minimum LNG injection of 0.8 Bcf/d, which is greater than the injections actually experienced since 2007, and a maximum LNG injection of 1.2 Bcf/d based on the historic coincidental peak.

- Electricity Imports: For each winter period, the scenarios assume energy imports across the external ties ranging from 2,500 MW to 3,500 MW. The scenarios assume 2,500 MW because, on average, over the last four winters (2013-2014 to 2016-2017), approximately 2,500 MW was flowing into New England just over 60 percent of the time. The analyses also consider import levels of 3,000 MW, which is close to the level experienced during the 2017-2018 Cold Spell, and what we have observed about 35 percent of the time during the winter period. Finally, the scenarios assume increased import levels of 3,500 MW to reflect a pending request for proposals for about 1,200 MW of clean energy imports.

- Dual-fuel Oil Tank Fill Rate: For each winter period, the scenarios assume oil storage tanks at dual-fuel generation facilities re-fill once (before the start of the winter period), or twice (before the start and during the winter months). Based on actual tank capacity (days), most dual-fuel units in the region can store five or fewer days' worth of oil, so filling their tanks twice would allow most units to burn oil for about ten days or less, requiring more replenishments.

Q: PLEASE DESCRIBE THE SCENARIOS USED TO SIMULATE WINTER SYSTEM OPERATIONS IN 2022-2023 AND 2023-2024 WITHOUT MYSTIC 8 & 9 AND DISTRIGAS.

A: In the Mystic and Distrigas Retirement Scenarios (see Tables 1 and 4, below), the ISO simulated system operations during the 2022-2023 winter and 2023-2024 winter without Mystic 8 & 9 with the model reflecting the above-specified assumptions and: (1) low LNG quantities ranging from 0.8 to 0.9 Bcf/d, representing injections from Canaport and the offshore buoy, as Distrigas is assumed to have ceased operation with the Mystic 8 & 9 retirements; (2) energy imports across the external ties ranging from 2,500 MW (as assumed in the OFSA's Reference Case) to 3,500 MW; and (3) oil storage tanks at dual-fuel generation facilities refilling either once or twice during the winter months.

Q: WHY DID THE ISO ASSESS THE EFFECTS OF THE MYSTIC 8 & 9 RETIREMENTS WITHOUT DISTRIGAS?

A: The Distrigas facility is the sole fuel source for the Mystic 8 & 9 generators, but by 2022, it will have the same owner as Mystic 8 & 9 (due to Exelon's acquisition of the LNG terminal for the stated purpose of fueling those generators). While Distrigas has operated as the equivalent of an on-site oil tank, it had separate ownership in the past, with separate business interests. It is already functionally a part of the Mystic facility and, as such, it is prudent for the ISO to consider the reliability impacts should Distrigas cease to operate when Mystic 8 & 9 retire. Moreover, Mystic 8 & 9 have always been Distrigas's largest customer, making it reasonable to anticipate that the retirement of Mystic 8 & 9 will have a negative effect on Distrigas's ability to continue to operate.

Accordingly, the ISO assessed the fuel-security reliability need with and without Distrigas operating. As I later discuss in my testimony, the ISO's analyses show the reliability need exists in both cases. Unacceptable reliability impacts occur simply with the loss of Mystic 8 & 9. The additional loss of Distrigas would exacerbate the region's fuel security situation, given that the facility has the capability of not only serving the needed Mystic generators, but also of injecting gas into the region's natural gas pipeline infrastructure even while fueling Mystic 8 & 9. The impacts of the loss of Distrigas in addition to Mystic 8 & 9 are presented, therefore, to ensure that there is transparency and an understanding of the negative operational impacts the loss of Distrigas can have for electric system operations – even apart from fueling the needed Mystic units.

Q: PLEASE DESCRIBE THE SCENARIOS USED TO SIMULATE WINTER SYSTEM OPERATIONS IN 2022-2023 AND 2023-2024 WITHOUT MYSTIC 8 & 9.

A: The Mystic Retirement Only Scenarios (see Tables 2 and 5, below) are the same as those described above, except the scenarios increase the assumed daily LNG injections. This is meant to reflect Distrigas's continuing availability. With Distrigas, these scenarios assume higher LNG levels throughout each winter, ranging from 1 to 1.2 Bcf/d.

Q: HOW DO THE MYSTIC RETIREMENT AND CONTINGENCY SCENARIOS DIFFER FROM THE SCENARIOS USED TO SIMULATE WINTER SYSTEM OPERATIONS IN 2022-2023 AND 2023-2024 WITHOUT MYSTIC 8 & 9?

A: The Mystic Retirement and Contingency Scenarios (see Tables 3 and 6, below) modeled contingencies of approximately 1,000 MW to 1,250 MW, with high LNG injections ranging from 1 to 1.1 Bcf/d, energy imports of 3,000 MW, and two refills of oil tanks at dual-fuel generating facilities during the winter months. The additional modeled contingencies of 1,000 MW to 1,250 MW on top of the modeled equivalent demand forced outage rates ("EFORd") is similar to the actual levels experienced during the 2017-2018 Cold Spell.

Q: DID THE ANALYSES MODEL THE EFFECTS OF LOGISTICS, SUCH AS LIMITATIONS ON THE FUEL-SUPPLY CHAIN OR THE GROWING EMISSION CONSTRAINTS ON THE REGION'S FOSSIL-FUEL GENERATORS?

A: No. For purposes of these analyses, the underlying study model reflects simplifying assumptions that are optimistic in contrast to actual experience. Like the OFSA, the scenarios described above do not consider market responses, fuel costs or prices, or emission constraints. The model assumes that prices in each scenario would sustain the inputs to that scenario. For example, if a scenario assumed 1 Bcf/d of LNG, the study assumes that electricity prices were high enough to sustain that amount of LNG in the market. The model also assumes unconstrained fuel-delivery logistics – that is, the model makes a very optimistic assumption that LNG cargos will arrive, and replenishments of oil tanks at dual-fuel and oil-fired generation facilities will occur, with no interruptions. The model also assumes the generation facilities are running at their EFORd, based on technology type, without air emissions constraints. It further assumes all generation facilities that cleared in the twelfth Forward Capacity Auction ("FCA 12") for Capacity Commitment Period 2021-2022 will be available in FCA 13 and in the fourteenth FCA ("FCA 14"), without accounting for any new de-list bids that may be submitted in FCA 13 or FCA 14 (other than those associated with retirement of the Mystic facility), or for any delays in new resources with stated dual-fuel generating capability that cleared in prior auctions. Finally, the model assumes an unconstrained transmission system, *i.e.*, all transmission facilities are assumed to be in service at full rated capability.

Q: HOW DO ACTUAL WINTER OPERATIONS COMPARE TO THE ASSUMPTIONS USED IN THE ANALYSES?

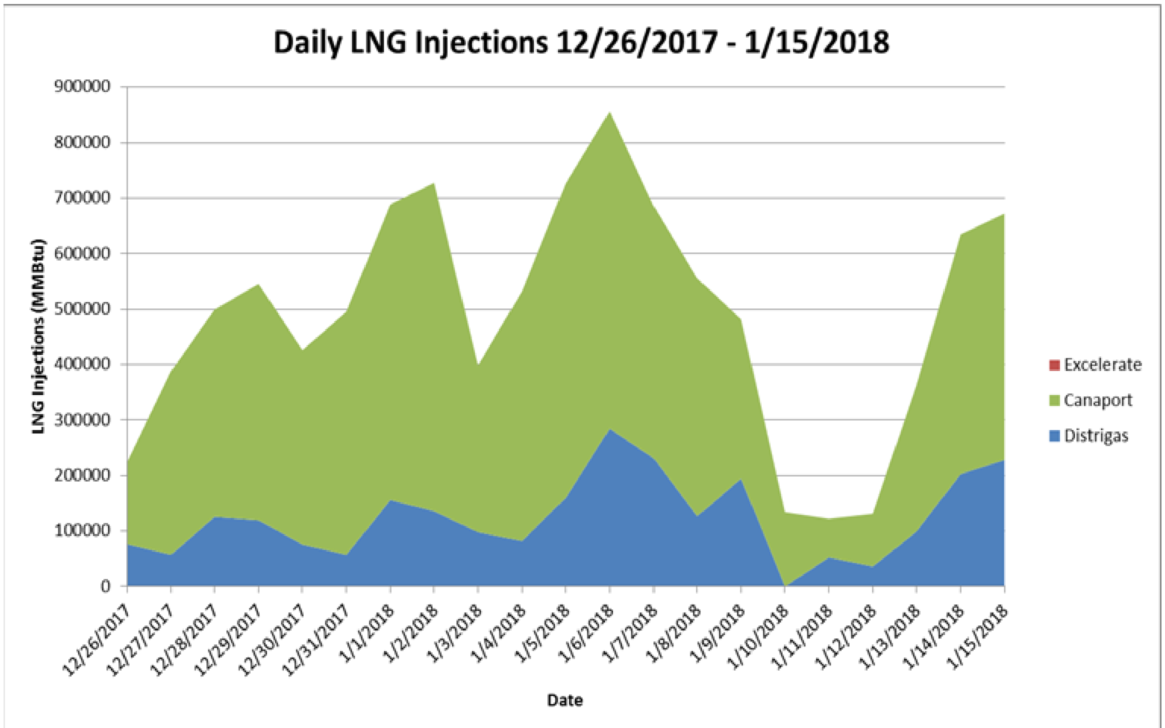
A: As noted, the assumptions used in the Mystic and Distrigas Retirement Scenarios, the Mystic Retirement Only Scenarios, and the Mystic Retirement and Contingency Scenarios are optimistic in comparison to what we have already observed in actual winter operations in various aspects.

First, the analyses evaluate each scenario's operational impacts throughout the 90-day winters of 2022-2023 and 2023-2024 based on the 90/10 peak load forecasts reflected in the Draft 2018 CELT Report (20,324 MW and 20,205 MW, respectively), which are approximately 300 MW and 400 MW, respectively, *less* than the actual peak load experienced during the 2017-2018 winter season (20,631 MW).

Second, except as indicated in the input assumptions, the model inputs assume no additional retirements of the system's remaining coal- and oil-fired generators, which have aggregate capacity of approximately 5,000 MW, and which are at risk of retirement even today due to stricter emissions limits and economic pressures.

Third, the assumed quantities of LNG in the studies – *i.e.*, from 0.8 Bcf/d to 1.2 Bcf/d – are seldom reached in New England, based on scheduling data available to the ISO. As the stack graph in Figure 4 below illustrates, during the 2017-2018 Cold Snap, daily LNG quantities ranged from as little as 122,000 MMBtu to a maximum (on a single day – January 6, 2018) of 855,000 MMBtu (approximately 0.855 Bcf).

Figure 4



Fourth, the studies assume oil storage tanks at dual-fuel generation facilities re-fill once or twice during the winter period. However, based on a review of surveys of oil-fired generation stations' fuel inventories submitted to the ISO,[17] from December 1, 2017 through March 1, 2018, 23 of the 39 generating stations with oil-fired capability greater

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[17] *ISO New England Operating Procedure No. 21 - Energy Inventory Accounting and Actions During an Energy Emergency*, ISO New England Inc. (June 15, 2016), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

than 50 MW performed some replenishment, but less than one full replenishment, of their tanks. Only three plants performed two or more full replenishments. The units that replenished more than twice had tank capacity equivalent to five days' operations or less, requiring them to replenish more frequently. The calculation of stored-fuel replenishment at these generating stations is based on the apparent delivery to the station divided by the maximum usable storage capacity of the station. The apparent delivery was based on the sum of the station's reported change in inventory and fuel burn reported for the applicable time period. A full replenishment was counted when the apparent delivery was equal to the maximum usable capacity of the station.

Fifth, the model used for the analyses assumes no emissions limitations and unconstrained fuel-delivery logistics. However, the 2017-2018 Cold Spell experience underscored some of the challenges to reliability posed by fuel-delivery logistics. While the system operated reliably through the extended cold weather period, it relied heavily on oil-fired generators to meet demand and maintain required operating reserves, introducing concerns with replenishment and emissions allowance constraints. Because oil-fired plants were used heavily during the extended cold weather, their oil inventories declined rapidly, and by the end of the cold spell, several large oil-fired generators had only enough fuel for a few more days of operation, with deliveries of more oil several days away. As we also experienced during the 2017-2018 Cold Spell, winter storms can delay deliveries of oil by road and LNG by sea; tanker truck drivers 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 barges, which are needed for the heavier oils used by some plants, when the entire East Coast is seeking to replenish supplies. Further, with extended days of burning oil, several resources were concerned about hitting federal and/or state emissions limitations or were restricted by such constraints. Indeed, during the first week of January 2018, some of the oil-fired generators that were running to keep the lights on were reporting to the ISO they were nearing their annual or rolling 12-month emissions limits.

Finally, the model utilized an EFORd based on technology type totaling 3,500 MW of generation assumed to be out of service, which, except for the Mystic Retirement and Contingency Scenarios, is much lower than the actual levels experienced during the 2017-2018 Cold Spell.

Q: HOW DID THE ISO MEASURE THE EFFECTS ON RELIABILITY IF MYSTIC 8 & 9 RETIRED IN 2022?

A: The ISO measured the operational impacts of the Mystic 8 & 9 retirements using the operational metrics applied in the OFSA – that is, full utilization of OP-4 actions, depletion of 10-minute operating reserves, and load shedding under OP-7. Mystic 8 & 9 would not be needed if the region could both maintain the required 10-minute operating reserves and avoid shedding load. In other words, the threshold criteria for fuel security were: (i) the core NERC Balancing Standard requirement related to maintenance of 10-minute operating reserves; and (ii) avoidance of load shedding, as load shedding indicates that the power system is unreliable.

As the Reliability Coordinator and Balancing Authority, the ISO is required to ensure that the New England Reliability Coordinator Area/Balancing Authority Area is operated at a prescribed level of reliability. To operate reliably, NERC and NPCC standards require the ISO to maintain 10-minute operating reserves sufficient to recover from the loss of the system's largest source of power, whether it is a large generator or a transmission line importing power. Maintaining 10-minute operating reserves is critical in New England, especially given the system's limited tie capability to the Eastern Interconnection. Because New England is radial to the Eastern Interconnection, the majority of the inertial pick up for a source loss (*i.e.*, the initial energy provided upon a source loss) comes across from our neighboring systems to the west. The magnitude of our source losses, which is greater than most other areas (over 1,400 MW), can and does cause transmission loading issues for the New England system and our neighboring systems to the west until the ISO activates 10-minute reserves to reduce the loading on the external ties. Ten-minute operating reserves are necessary to operate the system reliably and to comply with mandatory standards to respond to lost resources without burdening neighboring systems and potentially leading to uncontrolled outages that could cascade across New England and threaten the reliability of the entire Eastern Interconnection.

Like in the OFSA, as the system stress intensified in each of the scenarios assessing the loss of Mystic 8 & 9, the study model progressed through the series of actions specified in OP-4, in sequence, from: those that have no impact on electricity service to consumers, including depleting 30-minute operating reserves and scheduling an additional 500 MW of emergency energy import transactions; to procedures that have minor public impacts, including voltage reductions and requests for voluntary conservation; and then to the depletion of 10-minute reserves after fully exhausting all OP-4 actions, before finally resorting to load shedding under OP-7. For each scenario, the ISO calculated the load affected during the non-emergency and emergency actions under OP-4, including: the number of hours of 30-minute operating reserves depletion under Action 1; the number of hours, as well as the quantity of load affected, during the depletion of 10-minute operating reserves; and the number of days of load shedding and the quantity of unserved load, during OP-7 emergency actions.

Q: DID THE ANALYSIS FOR THE 2022-2023 AND 2023-2024 WINTER PERIODS RESULT IN A FAILURE TO MAINTAIN OPERATING RESERVES, AS YOU JUST DESCRIBED?

A: Yes. The analyses for both winters, even with some of the optimistic assumptions that I mentioned earlier, showed unacceptable reliability impacts to the power system.

Q: PLEASE DESCRIBE THE RESULTS OF THE ANALYSES FOR THE 2022-2023 WINTER PERIOD.

A: The results of the Mystic and Distrigas Retirement Scenarios, the Mystic Retirement Only Scenarios, and the Mystic Retirement and Contingency Scenarios for the 2022-2023 winter period are shown in Tables 1 to 3, below. The results of these analyses (as well as the analyses for the 2023-2024 winter period) are stated in terms of the frequency of instances when (1) ten-minute operating reserves would be depleted (a violation of reliability criteria); and (2) the electric system would have insufficient energy to meet system demand, and the ISO therefore would have to shed load, *i.e.*, rolling blackouts.

Table 1
2022-2023 Winter
Mystic and Distrigas Retirement Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
0.8	2,500	2	20,342	163,905	265	113,321	55,941	85,444	92	34,715	7	37	39
0.8	3,000	2	20,342	112,512	191	74,816	34,955	54,404	62	17,220	6	35	37
0.8	3,500	2	20,342	71,981	126	46,543	21,956	29,832	37	5,139	5	34	35
0.8	3,000	1	20,342	222,125	355	158,832	76,303	120,476	132	51,372	11	35	37
0.9	2,500	2	20,342	112,372	187	72,511	36,114	52,258	60	19,175	6	35	36
0.9	3,000	2	20,342	69,354	121	45,115	21,230	28,904	38	5,460	5	34	35
0.9	3,500	2	20,342	38,807	72	24,196	9,545	11,349	17	649	1	31	35
0.9	3,000	1	20,342	152,715	253	102,361	48,693	74,000	81	27,943	9	34	35

Table 2
2022-2023 Winter
Mystic Retirement Only Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
1	2,500	2	20,342	65,482	112	42,189	19,970	25,568	35	4,307	5	34	35
1	3,000	2	20,342	36,506	66	20,997	8,949	8,519	16	459	1	31	35
1	3,500	2	20,342	17,511	37	8,853	3,635	1,715	5	-	-	28	33
1	3,000	1	20,342	106,469	180	67,960	31,459	48,022	51	11,781	6	31	35
1.1	2,500	2	20,342	33,500	64	19,332	7,659	6,944	12	269	1	31	35
1.1	3,000	2	20,342	15,785	30	7,943	3,150	1,086	4	-	-	28	33
1.1	3,500	2	20,342	6,775	14	2,596	500	55	1	-	-	24	31
1.2	2,500	2	20,342	13,731	27	7,115	2,485	561	3	-	-	27	33
1.2	3,000	2	20,342	5,501	10	1,795	365	-	-	-	-	24	31

Table 3
2022-2023 Winter
Mystic Retirement and Contingency Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
1.1	3,000	2	20,342	38,993	72	21,076	8,542	8,821	13	204	1	28	33
1	3,000	2	20,342	83,911	151	53,857	24,237	34,960	40	4,974	5	31	35

Q: **PLEASE DESCRIBE THE RESULTS OF THE ANALYSES FOR THE 2023-2024 WINTER PERIOD.**

A: The results of the Mystic and Distrigas Retirement Scenarios, the Mystic Retirement Only Scenarios, and the Mystic Retirement and Contingency Scenarios for the 2023-2024 winter period are shown in Tables 4 to 6, below.

Table 4
2023-2024 Winter
Mystic and Distrigas Retirement Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
0.8	2,500	2	20,205	178,281	293	123,388	62,398	95,404	107	42,003	7	37	39
0.8	3,000	2	20,205	120,405	202	83,170	39,333	61,875	66	20,363	7	35	37
0.8	3,500	2	20,205	80,552	138	51,919	25,230	35,746	41	7,578	5	34	36
0.8	3,000	1	20,205	237,879	378	175,256	87,815	138,795	149	60,376	12	35	37
0.9	2,500	2	20,205	121,424	200	84,481	39,449	61,641	69	22,443	7	35	37
0.9	3,000	2	20,205	78,894	136	52,263	25,173	35,534	42	7,904	6	34	36
0.9	3,500	2	20,205	46,958	85	29,411	11,967	14,136	18	1,246	3	31	35
0.9	3,000	1	20,205	164,462	276	112,404	53,964	83,727	92	32,557	10	34	36

Table 5
2023-2024 Winter
Mystic Retirement Only Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
1	2,500	2	20,205	76,404	134	50,928	23,629	33,472	40	6,717	6	34	35
1	3,000	2	20,205	43,300	81	27,378	10,718	13,170	18	850	3	31	35
1	3,500	2	20,205	24,354	47	12,210	4,608	3,675	8	-	-	29	34
1	3,000	1	20,205	117,203	201	78,176	36,230	57,052	62	16,273	8	31	35
1.1	2,500	2	20,205	41,193	76	25,024	9,621	11,391	17	530	1	31	35
1.1	3,000	2	20,205	20,343	43	10,429	4,408	2,633	7	-	-	28	34
1.1	3,500	2	20,205	9,559	20	4,967	1,469	378	2	-	-	24	31
1.2	2,500	2	20,205	17,871	37	9,487	3,800	1,585	6	-	-	28	33
1.2	3,000	2	20,205	7,886	15	3,680	932	126	1	-	-	24	31

Table 6

2023-2024 Winter
Mystic Retirement and Contingency Scenarios

INPUTS				OUTPUTS									
				OP 4 Actions				10-Minute Reserve Depletion		OP 7 Action: Load Shedding		LNG	
LNG Cap (Bcf/Day)	Imports (MW)	Dual-Fuel (Oil Tank Fills)	Peak Load (MW)	Action 1 (MWh)	Action 1 (Hours)	Actions 2–5 (MWh)	Actions 6–11 (MWh)	Load at Risk (MWh)	Load at Risk (Hours)	Unserved Load (MWh)	Days	Max LNG Days	Days of ≥95% LNG at Assumed Cap
1.1	3,000	2	20,205	46,492	81	27,421	11,102	13,163	18	733	2	28	34
1	3,000	2	20,205	95,406	173	61,097	28,647	44,804	49	7,928	5	31	35

Q: DO THESE RESULTS INDICATE THAT MYSTIC 8 & 9 WILL BE NEEDED TO ENSURE THE ELECTRIC SYSTEM'S RELIABILITY DURING 2022-2024?

A: Yes, they clearly do. The analyses demonstrate significant risks to system reliability without Mystic 8 & 9, and even greater risks if Distrigas retires along with the Mystic units.

For example, the analyses show there would be violations of reliability criteria even under highly optimistic assumptions during the winter of 2022-23 if Mystic 8 & 9 were retired, even if Distrigas continued operating. Specifically, Table 2 (line 3) shows that 10-minute operating reserves would be depleted during multiple hours of winter operations, even assuming that LNG could be sustained at 1.0 Bcf/d for 28 days, 3,500 MW of energy imports would be available on the ISO's external ties for the entire winter, and oil tanks at all dual-fuel facilities would be fully refilled twice. The system's vulnerability is well illustrated by the outcome when imports are assumed instead to be 3,000 MW and dual-fuel oil tanks are replenished only once: 51 hours of depletion of 10-minute reserves and load-shedding totaling more than 11,000 MWh across six days during the 2022-2023 winter.[18]

When the ISO modeled even modestly greater generator outages consistent with the levels experienced during the 2017-2018 Cold Spell, even the scenarios that assume larger available LNG quantities (1.1 Bcf/d) show that 10-minute operating reserves will be depleted during multiple hours and that load shedding may be necessary.[19]

The results in all scenarios for the 2023-2024 winter period are slightly worse than the 2022-2023 winter, because natural gas consumption by local distribution companies increases, thereby reducing the already limited natural gas supply available for power generation.

[18] *See supra* Table 2, Line 4.

[19] *See supra* Table 3, line 1 and Table 6, line 1

The range of analyses conducted clearly shows that the retirement of Mystic 8 & 9 poses an unacceptable fuel security risk to the New England region, particularly during winter operations. The removal of these facilities further stresses the already limited fuel infrastructure. In the absence of these crucial facilities, when the region's natural gas pipeline system is constrained, we will become reliant on resources, such as coal-fired and oil-fired power plants that are at risk of retirement given economic and environmental pressures, or whose operation, as experienced during the 2017-2018 Cold Spell, is increasingly limited by emissions allowances and fuel-delivery logistical constraints.

It seems noteworthy that the only case in the ISO's studies in which the region would not experience a depletion of 10-minute operating reserves is the 2022-2023 winter scenario shown in Table 2, line 9. That scenario relies on assumed amounts of LNG seldom reached in New England, along with several other highly optimistic assumptions. Specifically, it assumes LNG deliveries could be sustained at 1.2 Bcf/d for 24 days, the external ties are loaded to 3,500 MW (3,000 MW plus another 500 MW with the implementation of OP-4, Action 5) for the entire winter, and dual-fuel units have 200% storage capability with no restrictions on replenishment or emissions, all on an unconstrained system with all available resources (nuclear, coal-fired, oil-fired, renewables) and fuel fully utilized up to the assumed capabilities and demand. All other scenarios unequivocally show unacceptable reliability impacts to the power system.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

DECLARATION

I declare under penalty of perjury that the foregoing Testimony of Peter T. Brandien on behalf of ISO New England, Inc., is true and correct, to the best of my knowledge, information, and belief.

Executed on May 1, 2018

Peter T. Brandien

Exhibit No. ISO-2

Testimony of
Richard L. Levitan and Sara Wilmer
on Behalf of ISO New England Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) Docket No. ER18-_____-000

TESTIMONY OF RICHARD L. LEVITAN AND SARA WILMER
ON BEHALF OF ISO NEW ENGLAND INC.

Q. Please state your name and business address for the record.

A. My name is Richard L. Levitan. My business address is Levitan & Associates, Inc., 100 Summer Street, Suite 3200, Boston, MA, 02110.

Q. Please state your name and business address for the record.

A. My name is Sara Wilmer. My business address is the same as Richard Levitan's.

Q. On whose behalf are you submitting this testimony?

A. Our testimony has been prepared on behalf of ISO New England Inc. (ISO-NE).

Q. By whom are you employed and in what capacity?

A. I, Richard L. Levitan, am President of Levitan & Associates, Inc. (LAI), a Boston-based energy management consulting firm specializing in the natural gas and electricity markets. I, Sara Wilmer, am a Managing Consultant at LAI. In this capacity we lead the firm's advisory services in the natural gas and electric industries, as well as providing expertise on matters related to gas supply and transportation management, wholesale power procurement, valuation, and wholesale market design.

Q. Please summarize the advisory services LAI offers clients in the natural gas and power industry.

A. LAI provides financial, economic, and engineering consulting services to gas and electric utilities, generation companies, investors, large end-users, state regulatory commissions, and independent system operators (ISOs) in the U.S. and Canada. LAI also conducts and provides oversight for wholesale power procurement in many states throughout the Northeast, mid-Atlantic, Illinois and California. In these capacities, we have helped guide the procurement of conventional resources, renewable energy technologies, transmission, and the array of physical and financial products that trading entities use to buy and sell electricity. LAI has advised diverse stakeholders throughout North America on matters involving gas supply and transportation management, contract administration, infrastructure deliverability, resource planning, and power system reliability. On behalf of the Eastern Interconnection Planning Collaborative (EIPC), LAI conducted a multi-year study of gas/electric interdependencies across the Eastern Interconnection affecting grid reliability and resiliency. This study addressed the adaptability of the pipeline network when gas- or electric-side contingencies occur. Since the early 2000's, LAI has worked closely from time to time with ISO-NE on diverse regional deliverability, gas/electric interdependencies, and scheduling protocols. LAI also conducts due diligence on natural gas and generation assets.

Q. Mr. Levitan, please summarize your professional experience and your educational background.

A. I have 40 years of experience in the energy industry. Since LAI's formation in 1989, I have advised market participants and regulatory bodies on diverse matters pertaining to competitive challenges in the natural gas, oil, and electricity industries. I have assisted many electric and gas utilities on the procurement of natural gas and pipeline transportation entitlements. I have advised ISOs on diverse matters associated with grid reliability. For ISO-NE, I served as project manager on a series of steady-state and transient flow hydraulic studies that examined gas pipeline and storage infrastructure adequacy. In my procurement oversight role, I have been responsible for ensuring the objectivity, fairness and transparency of various electric distribution companies' selection process as well as that of various state regulatory commissions. I have also advised state regulatory commissions and utilities on integrated resource planning, wholesale market design, and financial contracts. For the New York Independent System Operator (NYISO) and another ISO, I have provided advisory services covering pipeline and storage developments affecting deliverability to gas-fired generators. For the Connecticut Department of Energy and Environmental Administration, I assessed Dominion Energy's Millstone's economic prospects. For the Department of Energy, I evaluated natural gas resiliency to support the electric grid of the future as part of the recent Quadrennial Energy Review. I have advised a global offshore wind developer in New England on market, economic and regulatory issues supporting the addition of up to 800 MW. For Eversource Energy, I evaluated the (in)validity of the Environmental Defense Fund's allegations about vertical market power abuse by gas utilities in Connecticut. In this advisory capacity, I evaluated gas portfolio management and scheduling conventions.

From 1980 to 1989, I was a consultant at Stone & Webster Management Consultants, Inc. From 1978 to 1980, I was an Economist at Pacific Gas & Electric Co. I received my undergraduate degree from Cornell University (B.A., Arts & Sciences) and my masters from Harvard University where I specialized in energy economics. I attended a post-graduate executive management program at Stanford University. My resume can be found in Exhibit No. ISO-2.1.

Q. Ms. Wilmer, please summarize your professional experience and your educational background.

A. I have 15 years of experience in the energy industry. Since joining LAI in 2003, I have advised utilities, ISOs, state regulatory commissions and DOE on issues related to natural gas markets and gas/electric interdependencies. I have also advised private equity investors on valuation of gas assets. I manage LAI's pipeline hydraulic modeling practice, and have assessed natural gas infrastructure adequacy to meet electric generation gas demand on behalf of several eastern ISOs, including ISO-NE both individually and as part of the EIPC. I worked with Mr. Levitan on the Quadrennial Energy Review and refutation of vertical market power abuse assignment referenced above. Using gas simulation models, I have also been responsible for developing gas price forecasts and supporting and managing diverse energy procurements on behalf of utilities and state commissions.

I received my undergraduate degree from the Massachusetts Institute of Technology (B.S., Chemical Engineering). My resume can be found in Exhibit No. ISO-2.2.

Q. Mr. Levitan, have you testified before?

A. Yes. I have testified many times before the Federal Energy Regulatory Commission ("FERC" or the "Commission") on diverse matters. On behalf of ISO-NE, I submitted testimony on recommended modifications to Day Ahead scheduling protocols in accord with the Wholesale Gas Quadrant Standards. I have testified many times before state regulatory commissions in the U.S. and Canada. A list of my testimony experience is presented in Exhibit No. ISO-2.3.

Q. Ms. Wilmer, have you testified before?

A. No, I have not.

Q. Have you conducted fuel assurance studies in New England relevant to your assessment of Exelon's proposed retirement of Mystic 8&9?

A. Yes. In supporting various New England state procurements of renewable energy and clean energy technologies, we have coordinated gas and electric simulation modeling efforts that require inputs about liquefied natural gas (LNG) imports, the dispatch regime of both the LNG import facilities, and delivery conditions on the pipelines serving New England. In supporting ISO-NE, we have led LAI's technical assessment of the region's hydraulic capability, including extensive sensitivity analysis to gauge the adaptability of the gas network when gas contingencies are postulated to supply or transportation resources. In supporting EIPC, we have derived the frequency and duration of pipeline constraints in New England to serve non-firm, gas generation demand. A range of gas and electric contingencies were formulated in order to quantify in hydraulic models the resiliency of the gas network in New England to serve gas-fired generation, including delineation of mitigation measures. Other analysis was performed for EIPC pertaining to trucking logistics to support fuel assurance objectives during both cold snaps and hazardous driving conditions.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to demonstrate Mystic 8&9's role as Distrigas's largest customer and to explain the ramifications to Distrigas if Mystic 8&9 were to retire.

Q. Are you sponsoring any exhibits?

A. Yes, we are sponsoring the following exhibits:

Exhibit No.	Description
Exhibit No. ISO-2.1	Resume of Richard L. Levitan
Exhibit No. ISO-2.2	Resume of Sara Wilmer
Exhibit No. ISO-2.3	Testimony Experience of Richard L. Levitan
Exhibit No. ISO-2.4	Distrigas Vapor Sendout History
Exhibit No. ISO-2.5	Distrigas Sendout History to Algonquin and Tennessee
Exhibit No. ISO-2.6	Distrigas Sendout History to Mystic 8&9
Exhibit No. ISO-2.7	Distrigas Sendout History to Algonquin, Tennessee and Mystic 8&9
Exhibit No. ISO-2.8	Distrigas Estimated Vapor Sendout History to Boston Gas
Exhibit No. ISO-2.9	Distrigas Boiloff Deliveries History
Exhibit No. ISO-2.10	Distrigas Liquid Sendout History
Exhibit No. ISO-2.11	Historical Distrigas's Going-Forward Costs in 2006-08
Exhibit No. ISO-2.12	Forecast of Distrigas's Going-Forward Costs in 2022-24 with and without Mystic 8&9

Q. Were your analyses and these exhibits prepared by you or under your supervision?

A. Yes.

Q. Please summarize your principal findings and recommendations.

A. Distrigas has a long history of reliable performance serving customers in New England. Prior to 2012, sendout was roughly evenly split between Mystic 8&9 and Distrigas's other customers. However, deliveries to other customers changed substantially in 2012, and Mystic 8&9 now receives approximately two-thirds of Distrigas's sendout volumes. If Mystic 8&9 were to retire, the terminal's non-volumetric operating costs would be shared across a much smaller customer base, and an economic death spiral would likely ensue as those customers who were able to arrange alternative supplies also decontract.

Q. Please describe Distrigas's facility.

A. Distrigas of Massachusetts (Distrigas), a subsidiary of ENGIE, owns and operates the Everett Marine Terminal, which began operations in 1971 as a fully integrated LNG marine import, storage, and vaporization facility on a 35-acre industrial site in Everett, Massachusetts. It is the nation's oldest such facility and has provided gas supply to New England for nearly half a century.

Q. Please describe the gas supply services provided by Distrigas.

A. Distrigas provides four distinct gas supply services for the region: first, vapor sendout to Mystic 8&9; second, vapor sendout via the Algonquin and Tennessee pipelines; third, vapor sendout to the Boston Gas Company d/b/a National Grid ("Boston Gas" or "NGrid") distribution system; and, fourth, liquid sendout via truck to satellite LNG storage tanks located throughout New England. In May 2012, a vehicle fueling station was added to the terminal, but it is a low-volume service.

Q. Please describe Distrigas's vaporization capabilities.

A. Over the course of Distrigas's operating history, 1,035 MMcf/d of vaporization capacity has been installed. The initial vaporization capacity at startup was 135 MMcf/d, connecting the terminal to the local low-pressure (220 psig) Boston Gas distribution system. An additional 150 MMcf/d of vaporization capacity was later added to supply Algonquin through a medium-pressure (433 psig) connection as annual import volumes increased. A high-pressure (750 psig) connection to Tennessee was activated in January 1999 with the addition of another 150 MMcf/d of vaporization capacity.

Construction of the final 600 MMcf/d of vaporization capacity to support high-pressure deliverability to Mystic 8&9 was completed in 2002. This final block of vaporization capacity included four 150-MMcf/d vaporizers. Three of these vaporizers are designed to be used at part-load to meet Mystic 8&9 requirements, while the fourth serves as supplemental vaporization that can be used as backup capacity during maintenance to other units or on high demand days. The new vaporizers were also tied into the existing vaporization systems to enhance reliability and serve other connections. The sustainable vaporization capacity of the facility is 715 MMcf/d.

Q. How did the addition of incremental vaporization capacity change terminal sendout?

A. Exhibit No. ISO-2.4 shows the vapor sendout quantities reported by Distrigas to FERC in its Semi-Annual Operational Reports from 1995 through 2017. The addition of vaporization capacity to supply Tennessee corresponds to the increase in vapor sendout in the first half of 1999. Distrigas reported on June 26, 2002 that commissioning and start-up was underway for the four incremental vaporizers associated with the provision of service to Mystic 8&9. The phased increase in total vapor sendout from the second half of 2002 to the second half of 2003 corresponds to the flow of test gas to the power plant prior to Mystic 8 beginning commercial operation on April 14, 2003 and Mystic 9 beginning commercial operation on June 10, 2003.

Q. What is the history of Distrigas's sendout to Algonquin and Tennessee?

A. Following the installation of incremental vaporization capacity in 2002, Distrigas's maximum sendout to Algonquin and Tennessee is 276 MMcf/d and 163 MMcf/d, respectively. Exhibit No. ISO-2.5 shows Distrigas's daily sendout to Algonquin and Tennessee from June 2003 through March 2018 based on data collected from the pipelines' electronic bulletin boards (EBBs). Prior to 2012, sendout to the pipelines occurred generally consistently, with some seasonal variation. Following the 2011-12 heating season, receipts outside of the peak heating season are significantly reduced, often with no volume flowing on summer days. For example, during 2017 neither Algonquin nor Tennessee received any gas from Distrigas between May 18th and October 10th. During the peak heating season, however, the pipelines receive volumes from Distrigas more consistently, reaching pre-2012 levels on some days.

Q. Why did sendout patterns to the pipelines change in 2012?

A. High gas demand for generation in Japan following the March 2011 Fukushima disaster sustained upward pressure in Global LNG prices, thereby motivating suppliers to move LNG into the premium market in Asia. As we understand it, tightened supplies across the Atlantic Basin and higher oil-indexed pricing induced ENGIE to limit the volume of gas available to the New England market and hold a reverse auction for seasonal services from Distrigas in spring 2013.

Q. What is the history of Distrigas's sendout to Mystic 8&9?

A. Following the installation of incremental vaporization capacity in 2002, Distrigas's maximum sendout to Mystic 8&9 is 250 MMcf/d. Exhibit No. ISO-2.6 shows Distrigas's daily sendout to Mystic 8&9 from June 2003 through December 2017 based on heat input data collected from the Environmental Protection Agency's Clean Air Markets Program database and from January through March 2018 based on non-public data provided by ISO-NE. Vapor sendout to the plant was consistently high, with seasonal variations, through the end of the 2013-14 heating season. Volumes were then reduced through the first half of 2015, returning to previous levels for summer 2015 and remaining at those levels with the exception of September, October and November each year.

Q. What is Distrigas's combined daily sendout to Algonquin, Tennessee and Mystic 8&9?

A. Exhibit No. ISO-2.7 shows the total daily vapor sendout to Algonquin, Tennessee and Mystic 8&9. With the decrease in pipeline sendout since 2012, vapor sendout is approximately one-half of what it was previously at times when Mystic 8&9 are operating fully.

Q. What is the history of Distrigas's vapor sendout to Boston Gas?

A. Following the installation of incremental vaporization capacity in 2002, Distrigas's maximum sendout to NGrid is 233 MMcf/d. Daily sendout data to Boston Gas are not publicly available, but average volumes can be approximated based on the total six-month vapor sendout from Distrigas's Semi-Annual Operational Reports to FERC and the known sendout to other systems. Exhibit No. ISO-2.8 shows that Distrigas's estimated sendout to Boston Gas has also significantly decreased since 2012.

Distrigas additionally delivers up to 50 MMcf/d of boiloff gas to NGrid. Exhibit No. ISO-2.9 shows the deliveries from Distrigas's Semi-Annual Operational Reports to FERC.

Q. What is Distrigas's liquid sendout capacity?

A. Distrigas has four loading bays and can send out up to one million gallons per day of LNG by truck, equivalent to 100 MMcf/d of vapor.

Q. What has the historical level of liquid sendout been?

A. Exhibit No. ISO-2.10 shows the liquid sendout quantities reported by Distrigas to FERC in its Semi-Annual Operational Reports from 1995 through 2017. Based on the truck sendout capacity of 100 MMcf/d, the capacity factor has ranged from 5% to 35% in recent six-month periods. As we understand it, variation in liquid sendout levels is the result of variation in severity of winter weather and resultant LDC demand and LNG storage drawdown, and certain large LDCs in New England diversifying their respective portfolios by sourcing truck-transported LNG from Quebec and Pennsylvania for the summer refill period.

Q. Have you considered Distrigas's going forward prospects if Mystic 8&9 were to retire in 2022?

A. Yes. The economic synergy between sendout to the pipelines, NGrid and Mystic 8&9 allows Distrigas's cost of service to be recovered across a portfolio of gas and power loads. If Mystic 8&9 were to retire in 2022, Distrigas would lose most of its revenue, and to remain viable, would necessarily seek to recover its still-substantial fixed costs from its remaining customers receiving supplies via Algonquin, Tennessee and NGrid, and truck deliveries.

Q. How did you forecast the impact of Mystic 8&9's retirement on Distrigas's financial viability for the period 2022-24?

A. We estimated Distrigas's gas volumes with and without Mystic 8&9 for 2022-24 by examining the market dynamics driving past vapor and liquid sendout. Next, we forecasted Distrigas's going-forward costs in 2022-24 with and without Mystic 8&9. Finally, we forecasted the margin Distrigas would have to earn on those reduced LNG volumes in order to recover its going-forward costs.

Q. Please define Distrigas's going-forward costs.

A. Going-forward costs include five components: operating expenses, maintenance expenses, administrative expenses, real estate taxes, and capital expenditures (CapEx). These costs are incurred to operate the terminal facility in accord with federal, state, and local requirements. Virtually all of Distrigas's going-forward costs would be avoided if the terminal were retired. Operating expenses are predominantly volumetric and would decline more or less commensurate with the reduction in volumes if Mystic 8&9 were to retire but Distrigas were to continue serving other gas loads. For the sake of simplicity, we treated all other cost categories as fixed, but recognize that certain savings might accrue with the reduction in LNG volumes. At present, we have no way of knowing how such fixed costs might be reduced if Mystic 8&9 were to retire so we left them unchanged. This categorization of going-forward costs is meant to be consistent with ISO-NE's RMR payment provisions in Market Rule 1.[1]

Q. What data sources did you rely upon to forecast Distrigas's going-forward costs?

A. We had two sources of data. From 2006 through 2008, Distrigas submitted FERC Form 2 Annual Reports. These FERC Form 2 reports are complete and reliable, but they are not current, and also represent Distrigas's cost of service prior to the Natural Gas Act regulatory changes from Section 7 to Section 3. We averaged Distrigas's expenses over those three years to establish a basis (roughly in 2007 dollars) that would smooth out any anomalous values. As a reasonableness check, we also referred to Distrigas expense information that Exelon has provided to ISO-NE. In preparing this testimony, we relied on the Distrigas's FERC Form 2 data, adjusted for recent LNG volumes and escalated to 2022-24.

Q. How did you forecast Distrigas's operating expenses, the first going-forward category?

A. The FERC Form 2 required Distrigas to provide operating expense data for sixteen categories. The largest operating expense component was fuel to vaporize the LNG for sendout as natural gas. Distrigas's operating expenses totaled \$26.6 million, \$24.5 million, and \$27.0 million in 2006, 2007, and 2008, respectively.

We escalated the historical operating expense value to current (2018) and then future (2022-24) dollars by treating the fuel and power components separately from the other

[1] Section III.13.2.5.2.5.1 – Compensation for Bids Rejected for Reliability Reasons, and (ii) Section III – Appendix I – Form of Cost of Service Agreement. Under Article 4 of that Agreement, generators required for reliability are allowed to recover (i) variable costs, e.g. fuel and variable O&M costs, and (ii) fixed costs, e.g. fixed O&M, maintenance, and other costs that ISO-NE would negotiate with the RMR generator. We have not included any return of and on invested capital in Distrigas's going-forward costs. Insofar as Exelon has not transacted the acquisition of Distrigas, such acquisition costs are not sunk and may be recoupable in full or in part.

operating expense components. We escalated the fuel and power component by the change in annual Algonquin City Gate (ACG) prices from 2007 to 2017 (a decline of 55%) and then applied the U.S. DOE 2018 Annual Energy Outlook natural gas forecast to estimate 2022-24 values. We escalated all other operating expense components, *e.g.*, labor, by the change in the Gross Domestic Product: Implicit Price Deflator (GDPIPD) to arrive at 2018 values and then by the long-term average inflation rate of 2.0% through 2024. Since operating expenses are volumetric, we then averaged them over the volumes withdrawn in each year to arrive at an average unitized operating expense. This value was then multiplied by expected future Distrigas volumes with and without Mystic 8&9 to forecast operating expenses in 2022-24.

Q. How did you forecast Distrigas's maintenance expenses?

A. Distrigas reported maintenance expense data for eight categories in the FERC Form 2's for 2006-08. Distrigas's maintenance expenses totaled $3.8 million, $3.5 million, and $4.1 million for those years, respectively. We escalated the average of $3.8 million by the changes in historical GDPIPD and expected inflation to forecast Distrigas's maintenance expenses in 2022-24. Unlike operating expenses, maintenance expenses are not a direct function of LNG volumes, but are instead driven by the age of the facility, and by security, environmental, and other regulatory requirements. Therefore we did not reduce Distrigas's maintenance expenses in light of lower volumes without Mystic 8&9.

Q. How did you forecast Distrigas's administrative expenses?

A. Distrigas reported administrative and general (A&G) expenses of $20.6 million in 2006, $27.0 million in 2007, and $26.4 million in 2008. We escalated the average A&G expense of

$24.7 million by the change in the historical GDPIPD and expected inflation to forecast Distrigas's A&G expense in 2022-24.

Q. How did you forecast Distrigas's CapEx?

A. Distrigas provided beginning-of-year and end-of-year values for the LNG plant in service. The change in those values before any adjustments for depreciation or amortization is the CapEx for that year. We calculated CapEx of $14.0 million in 2006, $3.8 million in 2007, and $2.2 million in 2008. We escalated the average of $6.7 million by the change in the historical GDPIPD and expected inflation to forecast Distrigas's CapEx in 2022-24.

Q. How did you forecast Distrigas's real estate taxes?

A. Distrigas reported real estate tax expenses of $4.9 million in 2006, $3.6 million in 2007, and $3.9 million in 2008. We escalated the average of $3.8 million by the change in the historical GDPIPD and expected inflation to forecast Distrigas's real estate taxes in 2022-24.

Q. What is the total of Distrigas's going-forward costs in 2006-08?

A. The total was $65.4 million. All of these FERC Form 2 historical going-forward costs, which provide the basis for our forecast of Distrigas going-forward costs in 2022-24, are summarized in the following table and shown in more detail in Exhibit No. ISO-2.11. For simplicity sake, we assume that the average of the 2006-08 values is in 2007 dollars.

Distrigas Historical Going-Forward Costs ($ millions)

	2006	2007	2008	Average
Operations	$ 26.6	$ 24.5	$27.0	$ 26.0
Maintenance	$ 3.8	$ 3.5	$ 4.1	$ 3.8
Administration	$ 20.6	$ 27.0	$ 26.4	$ 24.7
Real Estate Taxes	$ 5.0	$ 3.6	$ 3.9	$ 3.8
Capital Expenditures	$ 14.0	$ 3.8	$ 2.3	$ 6.7
Total Going-Forward	$ 70.0	$ 62.5	$ 63.6	$ 65.4

Q. What was the volume of LNG withdrawals (as liquid and as vaporized gas) during the 2006-08 period?

A. Distrigas reported LNG withdrawals in the FERC Form 2 filings of 170.0 million MMBtu in 2006, 191.9 million MMBtu in 2007, and 183.5 million MMBtu in 2008. These volumes are generally consistent with those in the Semi-Annual Operational Reports submitted by Distrigas to FERC for the same period.

Q. When divided by the average of reported LNG withdrawals over 2006-08, what was the breakeven margin for Distrigas to have recovered those going-forward costs?

A. Based on the average level of LNG withdrawals in 2006-08, 182.1 million MMBtu, Distrigas would have to have recovered an average of $0.36/MMBtu to recoup those going-forward costs.

Q. How has the volume of LNG withdrawals changed over the past decade?

A. We reviewed the LNG receipts and withdrawals that Distrigas reported to FERC in the Semi-Annual Operational Reports through the second half of 2017. Over the past five years, LNG withdrawals reported in the Semi-Annual Operational Reports have averaged only 56 million MMBtu per year, considerably less than the levels observed in 2006-08.

Q. What do you expect the volume of LNG withdrawals to be for the years 2022-24?

A. LNG withdrawals in 2022 through 2024 will be driven by the dispatch of Mystic 8 & 9, weather conditions affecting the demand for seasonal services into Algonquin, Tennessee and NGrid, and the extent to which Distrigas is a source of LNG for refilling the satellite storage tanks throughout New England. Based on average sendout over the five year period from 2013 through 2017, we have estimated that Distrigas will send out the same volumes in the future, an average of 56 million MMBtu annually from 2022-24. This is a simplifying assumption and we have not conducted any sensitivity analysis to reflect much higher or lower demand for seasonal services from Distrigas. About two-thirds of the recent total product demand is associated with fuel delivery to Mystic 8&9. The remainder is associated with vapor and liquid sendout as shown in the following table.

Breakdown of Estimated Average (2022-24) LNG Withdrawals

	Sendout Volume (million MMBtu)	Share of Total Sendout
Mystic 8&9 Vapor	36.3	65%
Non-Mystic 8&9 Vapor	10.3	18%
Liquid Sendout	7.7	14%
Boiloff Deliveries	1.8	3%
Total	56.0	100%

Q. If Mystic 8&9 remain in business, how much would Distrigas have to charge above the landed cost of LNG in order to cover its going-forward costs in 2022-24?

A. Based on the aforementioned assumptions, we calculate that Distrigas would have to charge an average of $1.07/MMBtu in 2022-24 to cover its going-forward costs with Mystic 8&9 in service, as shown in Exhibit No. ISO-2.12. This unitized going-forward cost reflects the simplifying assumption that the capacity factor of Mystic 8&9 under an RMR reflects recent operating history rather than a materially different profile and level to optimize LNG imports at Distrigas in relation to the variables affecting global valuation.

Q. How does this forecast of going-forward cost compare to the average in 2006-08?

A. The average going-forward cost in 2006-08 was $0.36/MMBtu. Hence, with Mystic 8&9 continuing to operate, the 2022-24 going-forward cost would be about triple the baseline going-forward cost stated in nominal dollars. While some of this large increase is explained by inflation, most is explained by the much lower total annual volume of LNG withdrawals associated with recent experience. Any savings due to the reduction in Distrigas's variable operating expenses is eclipsed by unitizing Distrigas's fixed going-forward costs over much lower volumes.

Q. If Mystic 8&9 were to retire in 2022, how would Distrigas's sendout and going-forward costs change?

A. Based on the breakdown of estimated average LNG withdrawals provided in the previous table, Distrigas's sendout would be reduced by a further 67% without Mystic 8&9, because boiloff would also be reduced. While Distrigas's operating expenses would decline even further due to the lower LNG withdrawals, fixed going-forward costs would remain the same, and the per MMBtu costs that Distrigas would need cover with sales to its remaining customers would materially increase. As we see it, the higher unitized costs would begin a "death spiral" for Distrigas as customers over time cultivate economically-priced supplemental gas substitutes. Distrigas's projected going-forward costs without Mystic 8&9 are summarized in the following table.

Distrigas Projected Going-Forward Costs without Mystic 8&9 ($ millions)

	2022	2023	2024	Average
Operations	$ 4.7	$ 4.8	$ 5.0	$ 4.8
Maintenance	$ 4.9	$ 5.0	$ 5.1	$ 5.0
Administration	$ 32.0	$ 32.7	$ 33.3	$ 32.7
Real Estate Taxes	$ 4.9	$ 5.0	$ 5.1	$ 5.0
Capital Expenditures	$ 8.7	$ 8.9	$ 9.1	$ 8.9
Total Going-Forward	$ 55.3	$ 56.4	$ 57.6	$ 56.4

Q. Without Mystic 8&9, how much would Distrigas have to charge above the landed cost of LNG in order to cover its going-forward costs in 2022-24?

A. Based on the aforementioned assumptions, we calculate that Distrigas would have to charge an average of $3.21/MMBtu in 2022-24 to cover its going-forward costs with Mystic 8&9 no longer in service.

Q. How does this forecast of going-forward costs compare to the average in 2006-08 and the estimated going-forward costs with Mystic 8&9 in 2022-24?

A. The estimated going-forward costs without Mystic 8&9 is approximately nine times greater than the 2006-08 baseline going-forward costs stated in nominal dollars, and triple the going-forward costs in 2022-24 with Mystic 8&9.

Q. Are you concerned with the resultant economic onus borne by Distrigas's other customers in the absence of Mystic 8&9?

A. Yes. The comparatively recent sustained decline in seasonal services to shippers on Algonquin and Tennessee, as well as NGrid, might result in an economic death spiral for Distrigas. At a minimum, it would result in an immediate, substantial run-up in the price of liquid and vapor sendout from Distrigas. Not all customers are equally dependent on Distrigas. Therefore, those customers that are price inelastic in the short to intermediate term would likely bear all or the supermajority of costs.

Q. If Mystic 8&9 retire, do you have an opinion regarding whether or not Distrigas would be able to limp along serving the array of seasonal vapor services and satellite tank liquid refill that other customers utilize?

A. Yes, we do. The loss of Distrigas's largest customer would shift the economic burden of running the existing facility to gas network load in southern New England, in particular, those smaller LDCs dependent on truck transported LNG to replenish depleted inventory throughout the heating season. Over time, these smaller LDCs would likely find more economic alternatives to continued purchases from Distrigas. As previously mentioned, the loss of Distrigas's largest customer probably signals the death knell for continued Distrigas operation.

Q. That sounds dramatic. Why is a death spiral on the horizon for Distrigas without Mystic 8&9?

A. Distrigas's diminished load without Mystic 8&9 forces captive, inelastic customers to shoulder the burden for an interim period prior to the implementation of requisite mitigation measures. The increase in the weighted average cost of gas associated with preserving Distrigas would likely be large, but would not in and of itself be fatal regarding continued financial support for Distrigas's continued operation without Mystic 8&9.

Distrigas is well-positioned to line up international cargoes under contract to serve Mystic 8&9 throughout the year, with service to other customers as a part of that portfolio. However, in our opinion it would be difficult to line up the one cargo that would be needed to serve only Distrigas's other customers, with an option on a second cargo just in case. If Mystic 8&9 are not operating, Distrigas would likely have to rely on a destination-flexible cargo or incur an illiquidity premium for a small-volume (one or two cargoes) short-term contract. Insofar as LNG is currently an integral part of the LDCs' ability to meet their design criterion each winter, reliance on destination-flexible, spot cargoes may not be deemed sufficiently reliable by LDC counterparties.

Worse still, Distrigas would likely require counterparties to take-or-pay for the LNG supply in order to avoid taking on market risk in the event that a winter is warmer-than-normal and/or if no cold snaps occur. A requirement that the LDCs foot the entire bill for Distrigas's continued operation through a *de facto* take-or-pay contract might be poorly received by state regulatory commissions, which generally disfavor the potential creation of a stranded cost liability.

Q. Do customers other than Mystic 8&9 have alternatives to service from Distrigas?

A. Yes, to some degree.

Q. Please briefly describe the alternative sources of liquid supply.

A. Liquid refill and replenishment can be, and in some cases already is, being supplied from facilities operated by Énergir, formerly known as Gaz Métro, in Montreal, Quebec, and by UGI Energy Services Inc. (UGI) from multiple facilities located Pennsylvania. The current total market share of these companies in New England is small relative to Distrigas's, but it is significant and growing. Additionally, some of the larger LDCs have taken steps to make alternate arrangements to refill their satellite tanks. NGrid LNG, for example, has submitted an application to FERC to add 20 MMcf/d of liquefaction capacity to its 2-Bcf Fields Point storage tank in Providence, RI that would be used to fill that tank and would also allow NGrid to truck LNG to its other storage tanks in the region. Connecticut Natural Gas is also in the process of refurbishing the liquefaction equipment at its Rocky Hill satellite storage facility. Finally, Liberty Utilities and Northstar Industries are developing the Northeast Energy Center, which would be located in central Massachusetts and connected to Tennessee. The facility is designed with 20 MMcf/d of liquefaction and capacity and 0.2 to 0.7 Bcf of storage capacity to provide liquid services to LDCs in the region, including NGrid. The facility would be FERC-jurisdictional, and subject to rate caps.

Q. Please briefly describe the alternative sources of vapor supply.

A. Liberty Utilities has proposed to build a liquefaction and LNG storage facility in New Hampshire that would provide up to 150 MMcf/d of vapor sendout. Generally, while west-to-each transportation capacity is fully subscribed on Algonquin and Tennessee, there is unsubscribed east-to-west capacity on both systems. Algonquin's other eastern receipt points are interconnections with M&N and Excelerate Northeast Gateway. Tennessee's other eastern receipt points are interconnections with the M&N/PNGTS Joint Facilities at Haverhill and Dracut. These receipt points could receive supply from a combination of regasified LNG from Canaport and Northeast Gateway and supplies into TransCanada from Dawn and other sources. Several LDCs, including Berkshire Gas, Columbia Gas of Massachusetts, NGrid and NSTAR Gas, currently have precedent agreements pending before the Massachusetts Department of Public Utilities to contract for east-end supplies and east-to-west transportation on Tennessee. At the point when east-to-west capacity is also fully subscribed, additional capacity would require infrastructure expansion.

Q. How do the costs and challenges of these alternatives compare with continued service from Distrigas?

A. Alternatives which involve construction of new infrastructure or hardening of winter trucking logistics do involve many challenges, especially compared to the continuation of the status quo Distrigas service. We have not estimated the costs of the alternatives, but believe that there would be a point at which a continued reduction in sendout from Distrigas would increase volumetric charges enough that the costs of alternatives would become competitive. As noted earlier, a number of Distrigas's customers are already in the process of developing potential substitutes for the services currently provided by Distrigas.

Q. Please summarize your primary conclusions.

A. We have reached the following conclusions:

- Mystic 8&9 are by far Distrigas's largest customer, representing two-thirds of sendout in recent years.
- If Mystic 8&9 were to retire, Distrigas would need to recover its going forward costs entirely from its other customers. Based on LNG withdrawals during the 2006-08 baseline period, Distrigas recovered an average of $0.36/MMBtu. In 2022-24, if Mystic 8&9 are still operating, we have estimated an average charge of $1.07/MMBtu. If Mystic 8&9 are not operating and all going-forward costs are allocated to other customers, recoupment would need to be $3.21/MMBtu, about nine times the baseline charge experienced when sendout was robust about ten years ago. Costs may be further increased by premiums to arrange smaller-volume imports.
- With these much higher charges, those customers that are able to arrange alternatives, including new LNG infrastructure or transportation paths from other supply sources, would decontract from Distrigas, resulting in a death spiral as the unitized going-forward costs continue to increase.

Q. Does this conclude your testimony?

A. Yes, it does.

We declare under penalty of perjury that the foregoing is true and correct.

Executed on May 1, 2018.

Richard L. Levitan

Sara Wilmer

Resume of Richard L. Levitan

RICHARD L. LEVITAN

SUMMARY

A management consultant experienced in electricity and natural gas procurement, pipeline transportation management and infrastructure assessment, wholesale market design, long-term contracts, transmission pricing, and gas/electric simulation analysis.

PROFESSIONAL EXPERIENCE

1989 - **Levitan & Associates, Inc.**
President

1980 - 1989 **Stone & Webster Management Consultants, Inc.**
Vice President and Managing Officer (Boston)
Vice President
Executive Consultant
Senior Consultant
Consultant

1978 - 1980 **Pacific Gas & Electric Company**
Economist

CONSULTING ASSIGNMENTS

AUCTIONS & PROCUREMENT

Advised Connecticut Department of Energy and Environmental Protection on renewable energy and natural gas pipeline capacity procurement.

Served as Independent Evaluator (IE) on behalf of the California Public Utilities Commission (CPUC) regarding Southern California Edison's (SCE's) 2011 All Source Request for Offers (RFO) and 2012 Renewables RFO.

Served as IE on behalf of the CPUC regarding SCE's Non-Gas QF RFO.

Served as IE on behalf of the CPUC regarding SCE's Gas RFO.

Served as Agent on behalf of the New Jersey Board of Public Utilities (BPU) on the Long-Term Capacity Agreement Pilot Program (LCAPP). Responsible for implementation of the LCAPP, including formulation of Contracts-for-Differences covering 1,947 MW of new combined cycle plants. Applied Minimum Offer Price Rule. Performed simulation analysis of energy price effects. Testified before the BPU and in Federal District Court.

Provided technical support to the Long Island Power Authority (LIPA) regarding new generation and transmission projects, including Neptune Transmission, Caithness, fast track projects, and gas pipeline / local transportation contracts.

Conducted simulation analysis and transmission studies for LIPA in PJM and New England to support firm transmission withdrawal rights.

Responsible for Standard Service procurements for the Connecticut Public Utilities Regulatory Authority (PURA) regarding the standard service solicitations of Connecticut Light & Power (CL&P) and United Illuminating (UI). Procurement oversight has been provided six times per year since 2006.

Prepared the 2012 Connecticut Standard Service Procurement Plan governing changes to the UI and CL&P procurement paradigm, including self-management.

Provided testimony before CT PURA regarding the hedge benefits of long term contracts.

Served as "Prosecutorial" arm of PURA to support the selection of 540 MW of new quick-start peakers in Connecticut to meet ISO-NE's Locational Forward Reserve Market requirement.

Prepared procurement paradigm and contract framework on behalf of the Maryland Public Service Commission to support four electric distribution companies' (EDCs') long term resource requirements.

Provided technical support to four Massachusetts EDCs regarding long term renewable energy solicitation, including NStar's entitlement to Cape Wind.

Provided transmission and regulatory assistance in PJM in relation to NYPA's selection of the Hudson Transmission HVDC project.

Managed project team's market advisory and quantitative assessment of generation, fuel deliverability, and DC transmission options for LIPA's 2007 RFP. Identified primary risk factors associated with competing long term strategic alternatives. Submitted expert reports to the Governor's Office to support the selection of the Neptune HVDC project, including expected RTEP cost allocation for firm transmission withdrawal rights.

Managed project team's due diligence for LIPA regarding the election of Unforced Capacity Deliverability Rights (UDRs) on Neptune and Cross Sound Cable. Technical assessment covered transmission withdrawal rights, auction revenue rights, firm v. non-firm point-to-point transmission rights, and scheduling of internal bilateral transactions.

Evaluated wholesale procurement options for Freeport-McMoran (formerly, Phelps Dodge).

Represented Potomac Electric Power Co. in the transference of long term energy purchase contracts to Mirant.

INFRASTRUCTURE ASSESSMENT

Conducted due diligence on behalf of the Nova Scotia Consumer Advocate and Small Business Advocate on the proposed Maritime Link (ML) transmission project from the Lower Churchill Falls in Labrador to Nova Scotia. Assessed the project economics of the ML in relation to other renewable energy and import options to meet Nova Scotia's energy and environmental objectives. Submitted expert testimony before the provincial regulatory board. .

Represented LIPA in the technical assessment of gas pipeline and local delivery adequacy on the New York Facilities System to fuel proposed new combined cycle plants.

Conducted due diligence on behalf of NYPA in RFP #5 regarding pipeline and local delivery conditions to support new combined cycle plants in New York City. This effort encompassed extensive production simulation modeling, culminating in the selection of the Astoria Energy combined cycle plant.

Assessed transportation options for Bayonne Energy Center into New York City, including pipeline transport quality assessment on the Transco mainline and Leidy line.

Provided commercial support to LIPA regarding NGrid's on-Island buildout on the New York Facilities System to serve Fast Track Units. Provided commercial support to LIPA's Executive Management regarding the Omnibus Agreement between LIPA and NGrid governing local transportation service, imbalance resolution, netting, and other commercial provisions.

As LCAPP Agent for the BPU, evaluated delivery conditions on Transco and Texas Eastern to support fuel infrastructure adequacy for proposed new combined cycle plants in central and northern New Jersey.

Conducted due diligence on the proposed Broadwater Floating Storage Regasification Unit for the State of New York, including hydraulic delivery conditions, homeland security, environmental, and economic impacts.

Evaluated pipeline and local gas utility infrastructure to support the proposed quick start peakers in Connecticut on behalf of PURA.

Assessed fuel adequacy assessment for PJM, NYISO, and ISO-NE following hurricanes Katrina and Rita. Recommended risk mitigation measures for the winter of 2005/2006.

Evaluated storage and pipeline deliverability constraints for Stagecoach high deliverability storage field development in the Marcellus Shale basin. Identified system improvements on Tennessee required for phase two high deliverability expansion.

Advised ISO-NE on fuel diversity issues associated with the potential retirement or conversion of the Salem Harbor generation station.

Conducted steady state and transient flow analyses for PJM of pipeline and storage capability to serve core and non-core loads when contingencies occur.

Advised NextEra on pipeline infrastructure adequacy on Tennessee to serve the combined cycle plant in Rhode Island.

Advised TransCanada on bulk power transmission limitations affecting market options in the Northeast.

GAS/ELECTRIC INFRASTRUCTURE ADEQUACY

Advised Northeast Power Coordinating Council on gas/electric adaptability in New England under diverse contingencies.

Served as project manager on behalf of the Eastern Interconnection Planning Collaborative (PJM, NYISO, ISO-NE, MISO, TVA and the IESO of Ontario) on gas / electric interdependencies. Funded by DOE, this multi-year study included extensive mapping of all pipeline, storage and gas-fired generation infrastructure, constraint analysis of the frequency and duration of pipeline bottlenecks affecting scheduled gas-fired generation, hydraulic analysis of the resiliency of the pipeline network under postulated gas or electric side contingencies, and technical assessment of dual fuel capability, including local options.

Performed pipeline and storage deliverability assessment for NYISO, including quantification of at-risk generation when gas or electric side contingencies occur.

Served as project manager on US DOE second installment of the Quadrennial Energy Review regarding gas system capability in response to high renewable electricity assessment. Electric and gas simulation analyses covering the bulk energy system incorporated hydraulic analysis of constrained and unconstrained regions across the Eastern Interconnection.

Assessed residual oil and ULSD infrastructure across the New York Control Area for NYISO, including economic engineering assessment of dual-fuel capability in relation to firm transportation entitlements.

Assessed market expansion prospects for major pipeline company doing business in PJM.

Served as project manager on the Multi-Region Gas Study for PJM, IESO of Ontario, NYISO, ISO-NE, and NERC regarding pipeline and storage adequacy affecting bulk power security. Contingency analysis was conducted using electric and gas hydraulic models to determine the magnitude and duration of generation at risk, and the feasibility of short term pipeline workarounds. Economic / market modeling of supply chain management was performed to identify bottlenecks and throughput patterns under varying demand conditions.

Served as project manager on the steady state and transient flow analysis of the consolidated network of pipeline and storage resources to serve core and non-core generation load across PJM when gas or electric side contingencies are tested.

Provided support to ISO-NE Market Monitor regarding pipeline delivery conditions and market participant behavior during the cold snap of January 2004. Advised ISO-NE on formulation of cold weather protocols affecting gas-fired generator availability.

Served as project manager on the steady state and transient flow analyses for ISO-NE of gas infrastructure capability in New England to serve core and non-core loads when electric and gas side contingencies are postulated.

Advised ISO-NE and NEPOOL System Restoration Working Group on restart procedures governing natural gas plants in New England following a black out.

Conducted due diligence on two proposed off-shore LNG import terminals for the Massachusetts Department of Energy Resources, including hydraulic modeling to evaluate physical flow constraints and capacity benefits.

Assessed transportation deliverability constraints in the transient state on El Paso Natural Gas Co.'s pipeline network across metropolitan Phoenix for Salt River Project.

Evaluated post-restructuring transportation and natural gas supply procurement options for the Canal Unit. Conducted assessment of interruptible transportation quality and capacity release options on Algonquin's "G" lateral from Mendon.

TRANSACTION SUPPORT

Advised global offshore wind developer on economic, market and regulatory issues affecting development of up to 800 MW of wind generation in Massachusetts.

Represented leading private equity investor on storage asset acquisition in the Northeast.

Represented the State of Connecticut in its review of the NStar and Northeast Utilities merger.

Represented Con Edison Co. in its proposed acquisition of Northeast Utilities, including risk management assessment and ongoing litigation support.

Advised global investors on the acquisition of a wind portfolio in New York, New England, and New Brunswick.

Represented AllCapital on the acquisition of power plants located in New York City.

Represented TransCanada on the acquisition of power plants in the Northeast.

Represented Goldman Sachs in the acquisition of the 730 MW Linden generation asset in New Jersey and the 300 MW Variable Frequency Transformer Project into Staten Island.

Represented Power Gen on the acquisition of LG&E.

Provided market support for Public Service Resources Corporation on storage asset lease dispute under FERC jurisdiction in Nevada.

Restructured long term power purchase agreements (PPAs) for Con Edison, including technical simulation analyses of replacement energy under Standard Market Design and NYSRC reliability procedures.

Restructured long term PPAs for Puget Sound Energy, Potomac Electric Power Co., Commonwealth Electric, Public Service Electric & Gas, and Bonneville Power Administration.

Advised various U.S. and European investors groups regarding the purchase of generation assets divested by the New England Electric System, Boston Edison, Commonwealth Electric, Eastern Utilities Associates, Northeast Utilities, Pacific Gas & Electric Co., among others.

Represented Con Edison on the consensual termination of nine long term PPAs resulting in over $1.5 billion in ratepayer savings, including transactional support before the NYPSC.

Advised Con Edison on the securitization values of its QF portfolio, including all contracts covering gas supply, transportation, and steam.

Conducted resource planning studies regarding Con Edison's potential repowering opportunities at Ravenswood and Astoria.

Represented Puget Sound Energy, Commonwealth Electric, JCP&L, Bonneville Power Administration, Orange & Rockland Utilities, and PEPCO on the consensual termination or restructuring of long term PPAs.

Advised Associated Industries of Massachusetts on electric utility restructuring initiatives in New England.

Represented the Association Québecoise des Consommateurs Industriels d'Electricté (pulp and paper companies and aluminum smelters) on the potential restructuring of Hydro Québec.

Represented Bay State Gas Co. on the sale of a small power production facility.

Submitted expert testimony regarding competitive effects, market power effects, and opportunity costs attributable to NEES' transfer of non-nuclear assets to USGenNE.

LITIGATION SUPPORT

Represented NJ BPU on LCAPP litigation regarding the standard contract awards to LCAPP awardees, i.e., Hess, NRG, CPV.

Served as expert witness on behalf of NSTAR regarding its proposed 345 kV AC project submittal before the Massachusetts Facilities Siting Board.

Conducted continuing unit operation study of the 400 MW Newington Station for Public Service Co. of New Hampshire. Served as expert witness before NH Public Utilities Commission.

Served as project manager for Puget Sound Energy, Portland General Electric, Avista, Cascade Natural Gas, and Northwest Natural Gas Company on Gas Transmission Northwest rate case before FERC.

Served as expert witness for Southwest Gas Corporation on pipeline transportation matters before FERC.

Served as expert witness to eCORP on financial damages associated with AIG Highstar and West LB's administration of project loan covenants.

Provided support to Con Edison counsel on contract matters pertaining to cogeneration facilities in New York State and New Jersey.

Served as expert witness for Puget Sound Energy and Bonneville Power on diverse matters pertaining to Tenaska Ferndale, Tenaska Frederickson, Encogen and March Point.

Represented a financial estate on the matter of MMWEC's lawsuit arising from delays completing Seabrook.

Performed net income analysis of fossil generation facilities owned by Northeast Utilities and Public Service Co. of New Hampshire for property tax valuations.

Represented Salt River Project, Arizona Public Service Co., Phelps Dodge, Magma Copper, Asarco and Cyprus before FERC on multiple FERC dockets pertaining to transportation options on El Paso, Transwestern and Mojave pipelines, including both cost of service and certificate proceedings.

Represented Wheelabrator-Frackville in its contract disputes with Pennsylvania Power & Light on min-gen emergencies and economic dispatch.

Evaluated pipeline alternative cost allocation methods, capacity release mechanisms, buy/sells, and other general rate case issues for the Arizona Directs.

Provided expert testimony and litigation support on behalf of Pan Alberta Gas-U.S. on the matter of rolled-in rates on Gas Transmission Northwest and the potential expansion of PG&E's intra-state transmission system in California.

Represented Northern Municipal Distributors Group and Midwest Region Gas Task Force Association, a group of gas utilities in eight states served by Northern Natural Gas Co.

Represented New England Cogeneration Association before FERC regarding Northeast Utilities' merger with Public Service Co. of New Hampshire. Conducted market power concentration analysis.

Represented Industrial Gas Users group in Northern Nevada before FERC in Southwest Gas Co.'s spin-off of transmission properties to Paiute Pipeline Co.

Directed project team's assessment of El Paso Natural Gas Co.'s transportation service enhancements on behalf of gas and electric utilities in Texas, Arizona and New Mexico.

Conducted fuel supply and transportation analysis on CNG and Columbia including expert testimony on behalf of Doswell Energy Ltd. Partnership in its civil litigation with Virginia Power.

Led project team's assessment of financial risk for major offshore Arctic pipeline (Endicott) owned by British Petroleum, Exxon, Amoco and UNOCAL. Performed analysis of Endicott risks for ratemaking capital structure and return under FERC's trended original cost methodology prescribed in Order Nos. 154-B and C.

Determined appropriate ratemaking capital structure and rates of return for the Cochin Pipeline under Williams methodology.

Assisted in the prudency determination of South Jersey Gas Co.'s Distrigas LNG take-or-pay commitments in light of FERC order No. 380 and merchant service options on Transco.

PROJECT FINANCIAL ANALYSIS (OTHER THAN DIVESTITURE RELATED)

Conducted real options valuation of the Newington Station for Public Service Company of New Hampshire (PSNH). Performed financial and engineering assessment of PSNH's thermal fleet in light of changing wholesale market design changes.

Evaluated onshore and offshore wind project economics for NRG BluewaterWind, including financial assessment of loan guarantees and production tax credits.

Provided enterprise valuation of eCORP's Stagecoach ownership interest under option value measures.

Represented Westchester County on the potential decommissioning of the Indian Point nuclear power plants, including enterprise valuation analysis under Fair Market Value.

Represented Cornell University on the master energy plan for expansion of generation assets. Conducted real option value (ROV) analysis pertaining to solid fuel and natural gas based energy infrastructure improvements.

Represented University of Rochester on the selection and optimization of a cogeneration facility to meet UR's long term energy requirements.

Represented Rochester Institute of Technology on the selection and optimization of a cogeneration facility to meet RIT's long term energy requirements.

Represented The State University of New York on the development of combined heat and power facilities on 26 campuses.

Represented Great Bay Power Corporation's equity investors in the purchase of a minority share of the Seabrook station.

Evaluated financial merit of power technology options for the Massachusetts Water Resources Authority on Deer Island, including NStar's distribution rate unbundling proposal. Advised MWRA on modifications to operating procedures related to combustion turbine generators served by Spectra Energy off the Hubline lateral.

Evaluated the competitive economic merits of rival steam and power production technology options to serve the UMass at Amherst's energy plant requirements.

Performed fuel-related contract restructuring services for various gas-fired generators throughout New England.

Served as financial advisor to the various pension funds holding Osceola and Okeelanta bonds resulting from Florida Power & Light's *de facto* termination of the PPAs.

Evaluated NUG profitability levels for various developers under alternative project financing arrangements for competitive solicitations.

Evaluated QF power purchase contracts using decision risk analysis for leverage lease transactions and non-recourse debt financing for thermal and hydro projects in various stages of development.

Evaluated the financial and business risks surrounding a proposed new pipeline from Canada to New England. Supervised the market need assessment conducted by Stone & Webster to support Champlain's certificate application at FERC.

Conducted gas valuation condemnation study for City of Mesa, AZ; determined economic value of Mesa's gas properties; advised City Council on strategic options with Southwest Gas.

Evaluated impact of the National Energy Board's proposed market-oriented price regime on TransCanada's transportation toll methodology.

Revised internal accounting procedures for capital budgeting techniques for Union Gas, CentraGas, and Gaz Metro in Ontario and Quebec.

Structured loan guarantees and price supports for Synthetic Fuels Corporation filing on behalf of New England Energy Park coal gasification facility.

Conducted comprehensive review of financial modeling capability of Energy, Mines and Resources (EMR), Canada for a national distribution system expansion program. Derived real cost of capital for EMR used to support distribution system expansion in Ontario, Quebec, and British Columbia.

Performed financial analysis for the Territorial governments of Yukon and the Northwest Territories in regard to local gas distribution systems, small-scale LNG, and methanol.

RESOURCE ASSESSMENT & MARKET DESIGN

Evaluated (in)validity of EDF's allegations about vertical market power abuse by gas utilities in Connecticut for Eversource Energy.

Submitted testimony before FERC on behalf of ISO-NE regarding gas/electric scheduling protocols affecting generation unit availability in the Day Ahead Market.

Represented NSTAR on proposed 345 kV AC transmission project from Carver to Cape Cod to provide reliability benefits in Lower SEMA, including production simulation modeling of energy price impacts with the Carver to Cape Cod project relative to other resource options for Lower SEMA.

Assessed long term on-shore and off-shore wind potential in New England for ISO-NE.

Represented the Connecticut Office of Consumer Counsel on the state's two EDCs' 2010 Integrated Resource Plan, including technical assessment of demand side initiatives, renewables, and natural gas infrastructure. Provided testimony before the Department regarding procurement recommendations over a 10-year horizon.

Represented NRG, TransCanada Power, and USPowerGen (in-City generators) on the NYISO Demand Curve Reset procedure, including the derivation of the Cost of New Entry, the econometric determination of net energy profits, and other fuel-related parameters affecting the reset process.

Represented PURA on the potential restructuring of ISO-NE's Forward Capacity Market.

Conducted engineering economic analysis of conventional generation and renewable technology options to meet Maryland's long term resource options for the Maryland Public Service Commission (PSC). Evaluated the impact of backbone transmission projects in SWMAAC. Evaluated onshore and offshore wind options culminating in the MD PSC's selection of USWind and Skipjack to develop offshore wind resources to serve EDCs in

Maryland. Assessed the economic merit of the return to rate base regulation in Maryland using stochastic modeling techniques.

Represented Avista, Portland General Electric, Puget Sound Energy, and Northwest Natural Gas on pipeline transportation service options and pricing on Gas Transmission Northwest.

Conducted short and long term fuel price forecasts for ISO-NE.

Represented TransCanada regarding the competitive impacts among merchant generators associated with rival commodity gas pricing arrangements.

Evaluated pipeline decontracting initiatives associated with consensual termination of a large QF's gas supply, transportation and energy purchase contracts for El Paso Merchant Energy.

Conducted market forecasts of merchant income streams for major merchant power producers in New England, New York, and PJM.

Evaluated the feasibility of inside-the-fence cogeneration for Phelps Dodge at primary rod mill production plant.

Evaluated the feasibility of inside-the-fence cogeneration for a large paper mill in the inland southwest.

Evaluated the feasibility of inside-the-fence cogeneration for the MWRA.

Assessed competitive economics and merchant risk of a proposed 1,500 MW pumped storage facility in Ohio for Consolidated Hydro. Negotiated long-term preliminary arrangements for pumping power with Commonwealth Edison.

Evaluated power pricing and contract options for Enron Power's Milford project.

Advised HYDRA-CO Enterprise's cogeneration project at the Domtar Mill in Cornwall, Ontario in response to Vermont Department of Public Service RFP.

Prepared Gas Company of Hawaii's Integrated Resource Plan, including demand side management. Analysis included formulation of DSM strategy and alternative propane supply acquisition strategies.

Conducted market analysis of New England utilities' long-term resource requirements for Texaco's integrated gasified combined cycle plant.

Conducted inter-fuel substitution analyses for NGrid (formerly, KeySpan).

Evaluated pipeline deliverability impacts attributable to El Paso's proposed San Juan Triangle and Northern Mainline expansions, and East End Manifold proposal for the Arizona Directs. Assessed pipeline interconnection arrangements on Northern Natural and Natural Gas Pipeline of America.

Assessed rival NO_x and SO_2 pollution control strategies, emission effects, and compliance costs for Clark Public Utility District, WA.

Responsible for audit of West Ohio Gas Co.'s gas purchase and transportation policies. Conducted management audit of West Ohio Gas purchasing practices under state mandated least cost planning standards.

Responsible for Stone & Webster’s audit of Florida Power & Light Co.'s Resource Plan, including transmission effects and third party project development potential. Assessed impact of Florida Gas Transmission Co.'s expansion on third-party gas use. Advised CEO on investment strategies and investor relations.

Project manager on engineering economic and financial assessment of Texaco's coal gasification technology; examined IGCC merits under various ownership structures; conducted preliminary market study of IGCC suitability in Florida and California.

Acted as project manager for economic/financial analysis of proposed IGCC for Florida Progress Corporation utilizing decision risk-evaluation techniques.

Determined market and resource/economic strategy for the proposed 1500 MW IGCC at New England Energy Park.

Served as project manager for technical/economic assessment of natural gas/liquid fuel substitution prospects in the province of Newfoundland/Labrador, and the Yukon and Northwest Territories.

Evaluated monetary / financial issues related to a natural gas optimization study for the Government of Argentina, Energy Ministry. Activities included derivation of shadow prices for tradable petroleum products and recommended gas rate tariffs.

Determined the economic feasibility of a proposed oil to coal conversion project for GE’s Pittsfield Plant.

Retail & Wholesale Choice

Formulated risk management option programs for University of Rochester, Cornell University, Phelps Dodge, and Visy Paper.

Negotiated gas supply and transportation contracts for Texas Instruments. Profiled and aggregated gas and oil usage data from various plant facilities for purposes of energy procurement package.

Designed contract options for natural gas, oil and electricity for CareGroup, a network of Harvard hospitals in Massachusetts and Rhode Island.

Designed RFP and negotiated contracts for natural gas, oil and energy tolling for a Massachusetts municipal electric utility.

Represented GPU Energy on the transition to competitive choice in New Jersey.

Evaluated retail procurement options for the Massachusetts Water Resources Authority.

Evaluated retail purchasing options for Abitibi Consolidated in Ontario and Quebec.

Evaluated retail purchasing options for Visy Paper in New York.

Represented L'Association des Industries Forestières du Québec (Quebec's association of pulp and paper manufacturers) in the matter of design and implementation of unbundled electricity rates under a new regulatory framework in Quebec.

Renegotiated intermediate term retail electricity contracts for Holoyke Industrials, a large group of energy users in Central Massachusetts.

Negotiated contracts for fuel and/or transportation services for various electric utilities in Arizona.

Valued Northern Natural Gas Co.'s Canadian gas supply and transportation contracts for Northern Illinois Gas Co. in the pipelines Order 636 reverse auction.

Renegotiated Paramount Resources gas supply agreement with Selkirk Cogeneration Ltd.

Negotiated preliminary Canadian gas supply contract for major proposed cogeneration venture in Eastern Ontario.

Obtained gas supply from major producer for South Jersey Cogeneration project.

Negotiated gas and transportation contracts with British Gas on behalf of Lakeland Energy (the first commercial IPP in U.K.). Also led consortium negotiations for power sales agreement with the North Western Electricity Board.

Negotiated PPAs for first planned coal gasification facility in New England with Boston Edison, EUA, and MMWEC.

Assisted in the formulation of transportation contracts between New England utilities and Champlain Pipeline Co.

Negotiated power sales agreements for various hydro small power producers with Southern Company affiliates, and various California and New England utilities.

Conducted analysis of power contract pricing terms and conditions, including wheeling provisions, for various cogeneration projects.

Formulated tipping fees and steam power values for proposed Puerto Rican biomass facility. Negotiated letters of intent with cities of San Juan and Guaynabo.

Designed terms and conditions for interruptible and curtailable contract rates for Barbados Light & Power Co.

DUE DILIGENCE

Evaluated transmission requirements and economic impacts associated with firm transmission withdrawal rights to support NYPA's Hudson Transmission Project.

Derived generation asset portfolio value of existing gas assets in New England for Exelon.

Responsible for project financial valuations underlying generation asset valuations for international investors acquiring generation assets in New England, New York, and PJM.

Evaluated LG&E's market exposure in SERC for PowerGen.

Conducted due diligence on behalf of BankBoston regarding Constellation Power's acquisition of EDE Noreste in Panama.

Evaluated short list respondents' fuel supply plans for Clark Public Utilities District.

Provided senior lenders with technical opinions regarding the (re)financing of power plants in New York State.

Analyzed California border and burner-tip gas prices affecting contract avoided costs in loan covenants for Deutsche Morgan Grenfell.

Responsible for Stone & Webster's engineering and financial / economic assessment of Reading Culm circulating fluidized bed facility, including fuel and power purchase contracts with Pennsylvania Power & Light Co. for The Deerpath Group.

Responsible for Stone & Webster's economic, financial, and regulatory risk analysis for The Deerpath Group, the lessor of the 1370 MW Midland Cogeneration Venture.

RATE DESIGN

Evaluated NGrid's imbalance resolution, daily scheduling procedures, and penalty exposure for PSEG-Long Island associated with gas/electric scheduling.

Evaluated open access transmission tariffs in PJM, New York and New England for import / export from New York State on behalf of EDCs or generation companies.

Evaluated Noreste's distribution rates in Panama under alternative performance based ratemaking methods.

Evaluated commercial implications of various utility unbundling mechanisms for purposes of installing inside-the-fence cogeneration or third-party energy procurement.

Derived transportation rates and competitive impacts under roll-in versus incremental tolling proposals for shippers on Northwest Pipeline, Pacific Gas Transmission, El Paso Natural Gas, Iroquois, and others.

Performed technical rate calculations for LDCs and electric utilities. Conducted or assisted in the preparation of marginal costs studies for electric and gas utilities throughout the U.S., Canada and Barbados.

Assessed the refunctionalization of El Paso's and Northwest's transportation rates under FERC Policy Statement and Orders 637/636/500.

Formulated rates for firm/non-firm cogeneration purchases for various utilities. Applied various revenue reconciliation methods for marginal cost-based rates.

Evaluated Bonneville Power Administration's trigger price rate proposal for Intalco Aluminum Co., an aluminum manufacturer in the Pacific Northwest.

Determined promotional off-peak power rates for Barbados Light & Power.

PRIOR BACKGROUND

UTILITY EXPERIENCE

Conducted production simulation analysis to support long term cogeneration rates for standardized contracts for Pacific Gas & Electric Co. Assisted in cost of service studies and rate cases (1978-1980).

OTHER INDUSTRY

Evaluated the impact of airline deregulation on the major U.S. trunk carriers as a Research Assistant at the Harvard Business School (1977-1978).

EDUCATION

Cornell University
B.A., Arts & Sciences, 1975 (Phi Beta Kappa).

Harvard University
Masters, specialization in Energy Economics, 1978.

Stanford University
Post-graduate Industrial Organizational Management Program, Department of Electrical Engineering, 1979.

INDUSTRY PRESENTATIONS & PUBLICATIONS

"Renewable Initiatives in the Greater Northeast and Mid-Atlantic: A Rorschach Test on What's Beautiful and Believable," – Cornell Energy Connection, October 2017

"Infrastructure Update in New England," New England – Canada Business Council Energy Trade and Technology Conference, November 2016

"Eastern Interconnection Interdependency Report," Electric System Natural Gas Infrastructure Risk, Joint Meeting of Committee on Regional Electric Power Cooperation and Western Interconnection Regional Advisory Board, October 2016

"Natural Gas – What you Need to Know," Organization of MISO States, Annual Meeting, October 2016

"System Reliability Analysis: Infrastructure Disruptions, Delays and Potential Market Impacts," Northeast Gas Association, September 2016

"Chronology of Technical Assessments Affecting Pipeline Deliverability to New England," New England Roundtable, November 2015.

"Natural Gas / Electric Nexus in PJM," PJM Roundtable, October 2015

"Pipeline to Reliability," IEEE Power & Energy, Volume 12, Number 6, December 2014.

"EIPC Gas-Electric System Interface Study" Northeast Power Coordinating Council 2014 General Meeting, December 2014

"Finding Practical Solutions to Fuel Supply and Generation Capacity Problems" Infocast Northeast Energy Summit, September 2014

"Update on Gas-Electric Coordination in the Northeast" Infocast Northeast Energy Summit, September 2014

Regional Market Trends Forum "Ten Years After" Gas & Power in Perspective," May 2014.

"Infrastructure and Reliability Challenges for the Northeast Fuels Market," New England Energy Conference and Exposition, May 2014.

"BuildingEnergy14 Understanding Our Energy Distribution Systems" Northeast Sustainable Energy Association, March 2014.

"Understanding Our Energy Distribution Systems: Gas Infrastructure and Deliverability in New England," Northeast Sustainable Energy Association, March 2014.

"Polar Vortex Forensics: Initial Review of Key Drivers Affecting Power Prices in NYISO" Northeast Sustainable Energy Association, February 2014.

"Gas/Electric Interdependence: Challenges & Opportunities," New England Consumer Liaison Group Meeting, June 2013.

"How Coal Plant Retirements Will Drive Midstream Investment in the Midwest and Northeast," Infocast b2bwebinars, June 2013.

"Maine Energy & Environment Policy: Priorities for the 126th Legislature" March 2013.

"Market Dynamics Affecting Deliverability, Pricing and Strategic Opportunities in New England," September 2012

"Natural Gas / Electric Dependencies in a Clean Tech Economy," Harvard University School of Engineering and Applied Sciences Industry Presentation, Cambridge, Massachusetts, September 2012.

"Viewpoints on Current Events," NECA Fuels Conference Panel, Newton, Massachusetts, September 2012.

"A New Englander's Perspective: Shale Gas-Quantities, Price and What's to be Done?" NECPUC Symposium, Samoset, Maine, May 2012.

"Leaning on Line Pack," Public Utilities Fortnightly," January 2011.

"Growth Prospects for Appalachian Gas: Good Access Trumps Market Fundamentals," Platts 3rd Appalachian Gas Conference, October 2010.

"Future of Natural Gas in New England and Interaction with Electricity Markets," New England Roundtable, April 2010.

"Managing Inter-Dependencies Across Gas and Electricity," Carnegie Mellon University, Department of Electrical Engineering, December 2008.

"Capacity Price Frameworks in the Greater Northeast: Can you take them to the bank?" Infocast, Washington, D.C., June 2007.

"North American Gas Demand: How Gas & Power Markets are Reacting to Higher Prices and Weather Effects," Zeus Development Forum, Houston, December 2006.

"Does the Northeast Energy Market Grade an 'A,' 'F' or Something in Between?" LNG Express, Boston, September 2006.

"Functionality of Northeast Capacity Markets Under RPM, the Demand Curve and LICAP," Northeastern Power Supply Forum, Infocast, Philadelphia, June 2006.

"How Much Gas is Enough? Finding Incentives to Lessen the Gas Overbuild," Platts Northeast Power Markets Forum, Washington, D.C., March 2006.

“How LNG fits into the Regional Market,” New England Roundtable, Boston, February 2006.

“Outlook on Natural Gas and LNG in New England,” New England Roundtable, November 2004.

“Market Dynamics Driving LNG Growth Prospects,” INFOCAST, Boston, October 2004.

“An Outlook on Gas Commodity Prices and Market Fundamentals in The Northeast,” before The Energy Committee of The New York Bar Association, New York, April 2003.

“Value Drivers Affecting Pipeline & Storage Entitlements,” INFOCAST, Houston, September 2002.

“The Big Picture on Power Market Dynamics and Storage,” INFOCAST, Houston, June 2002.

“2002 Outlook on Gas Supply and Deliverability,” INFOCAST, Boston, January 2002.

“Technical Assessment of New England’s Natural Gas Pipeline Adequacy,” on behalf of ISO-NE, before New England Association of Energy Engineers, April, 2001; U.S. Department of Energy, Wye Workshop on Strategic Initiatives for Coal and Power, March, 2001; Northeast Energy and Commerce Association, March, 2001; Boston Bar Association, February, 2001; Massachusetts Roundtable, February, 2001; NEPOOL Reliability Committee, January, 2001; and, NEPOOL Participants Committee, January, 2001.

“Forecasting Equity Returns for Merchant Power,” INFOCAST, Atlanta, GA, September 2000.

“Maximizing the Value of QFs and IPPs in a Restructured Environment,” INFOCAST, Santa Monica, CA, July 2000.

“Valuing Transmission and Distribution Assets,” INFOCAST, Orlando, FL, January 2000.

“Build v. Buy: New Commercial Benchmarks,” International District Energy Association, Boston, MA, June 1999

“Monetizing Key Value Drivers,” INFOCAST, Buying & Selling Utilities’ Generation Assets, Boston, MA, November 1998.

“A Business Perspective on the Competitive Transition of the Electric Utility Industry,” American Bankruptcy Institute’s Fifth Annual Northeast Bankruptcy Conference, Falmouth, MA, July 1998.

“Uncertain ESCO Margins in New England’s Transitional Energy Markets,” Con Edison Energy conference on Supplying New Retail Markets, New York City, June 1998.

"PPA Buyouts and Restructurings: War Stories from the Trenches," Exnet conference on Industry Restructuring, Washington, D.C. 1997.

"Monetizing NUG Opportunity Costs," Sloan School of Management, Massachusetts Institute of Technology, August 1996.

"Natural Gas Procurement Options for Power Generators in New England," presented to New England Cogeneration Association's New England Gas Markets Conference, May 1995.

"The Emerging Secondary Market for Idled Transportation Capacity in the Northeast," presented to Executive Enterprise's Northeast Gas Markets Industry Conference, April 1994.

"Outlook for Gas-Fired Electric Power Generation in the Northeast through 2000," presented to Executive Enterprise's Northeast Gas Markets in the Post 636 Environment, November 1993.

"Gas Supply and Transportation Contract Issues: Implications for Cogeneration Project Financing," presented to annual symposium on Energy Planning sponsored by Niagara Mohawk Power Corporation, May 1993.

"A Post-Merger Outlook on Wheeling in New England: FERC Precedent Cloaked in a Merger," presented to Executive Enterprise's Second Annual Northeast Power Market Conference, May 1992.

"Transmission of Non-Utility Generation in New England," presented to Executive Enterprise's Third Annual Industrial & Utilities Conference, Chicago, IL, October 1990.

"Capital Structure and Rate of Return for Regulated Entities: the State Perspective v. FERC's View, Accounting Association of Oil Pipelines," Houston, Texas, February 1986.

"Demand-Side Management (DSM) Technologies for Island Utilities," St. Lucia West Indies, September 1985.

"Alternative Marginal Cost Methodologies since PURPA," Center for Professional Advancement, New Brunswick, NJ, May 1983.

"Utility Resource Selection-Decisions and New Challenges," Department of Electrical Engineering, Tufts University, April 1982.

Participated in biannual Stone & Webster Utility Management Development Program on gas price and Federal regulatory developments, cogeneration and marginal costs, 1982-1989.

ASSOCIATIONS (CURRENT AND PAST)

American Gas Association

International District Energy Association

Northeast Gas Association

Northeast Energy and Commerce Association (prior Board Member)

Resume of Sara Wilmer

SARA WILMER

SUMMARY

Ms. Wilmer has fourteen years of diversified experience in the electric power and natural gas industries and has established expertise across the U.S. and Canada in pipeline hydraulic and, economic modeling underlying gas / electric interdependencies. She also has experience in fuel price forecasting, gas utility operations, information technology, and administering wholesale power procurements, including managing procurement websites and implementing bid evaluation protocols. She is also experienced with pipeline and storage operational logistics, including regulatory applications before federal and state entities.

PROFESSIONAL EXPERIENCE

2001 – **Levitan & Associates, Inc.**
Managing Consultant
Executive Consultant
Senior Consultant
Consultant
Assistant Consultant
Research Assistant

CONSULTING ASSIGNMENTS

Advised Northeast Power Coordinating Council on gas/electric adaptability in New England under diverse contingencies.

Evaluated (in)validity of EDF's allegations about vertical market power abuse by gas utilities in Connecticut for Eversource Energy.

Analyzed gas-electric infrastructure adequacy for the Eastern Interconnection Planning Collaborative, including a review of current infrastructure, seasonal peak day assessment, post-contingency operational assessment and fuel assurance alternatives, covering the service areas of PJM, MISO, NYISO, ISO-NE, TVA and IESO. Tasks included detailed mapping of gas and electric infrastructure; evaluation of pipeline scheduling practices and service priorities and their impacts on electric generators; refinement of infrastructure inputs to gas models; development of residential, commercial, and industrial demand forecasts; coordination with FERC staff on CEII requests, and development and analysis of steady-state and transient hydraulic models. Participated in ongoing stakeholder meetings with EIPC and industry stakeholders, including trade associations.

Conducted analysis in support of expert testimony on behalf of ISO New England regarding changes to the day-ahead market schedule and the associated effects on fuel scheduling for gas-fired generators.

Supported gas-fired generation owner in discussions with local distribution company with respect to gas scheduling and balancing protocols and contract arrangements.

Evaluated infrastructure adequacy in New England over a five-year historical period and a five-year forecast period, over a portfolio of scenarios based on supply, demand, and infrastructure variables

Evaluated gas supply and transportation options for power plant being developed in New Jersey.

Developed intraday gas utility demand profiles and infrastructure inputs for gas-electric modeling system.

Geocoded and mapped small renewable projects participating in Illinois Power Agency RECs procurements.

Conducted technical evaluation portfolio of northeast gas storage assets on behalf of a private equity investor.

Conducted gas demand forecasting, infrastructure adequacy modeling, and hydraulic modeling to test gas-electric interactions under variable energy resource uncertainty, and coauthored report for the High Renewable Electricity Assessment of the Gas-Electric Interface study for U.S. DOE to support its second installment of the Quadrennial Energy Review.

Prepared gas market inputs for the tri-state Clean Energy RFP, including LDC demand forecasts, gas supply portfolios, and capacity expansions plans.

Developed gas price forecasts for various clients.

Evaluated gas infrastructure expansion market opportunities in the Philadelphia area.

Calculated gas infrastructure demand and transport cost parameters for an integrated gas-electric market simulation model.

Supported preparation of a short-term gas price forecasting model for New England.

Evaluated adequacy of pipeline infrastructure in the New York Control Area to meet electric generation needs over a five-year study horizon using a state-wide flow balance model.

Developed fuel supply plan for generator responding to New York Power Authority RFP for Contingency Procurement of Generation and Transmission under the New York Energy Highway Initiative.

Analyzed historical congestion patterns on pipelines serving the New York Control Area.

Estimated costs of pipeline expansions to provide firm transportation service to gas-fired generators in New York State relative to the cost of adding dual-fuel capability.

Represented LIPA in the 2010 Generation & Transmission RFP regarding gas pipeline and local delivery adequacy on the New York Facilities System to fuel new combined cycle plants and/or peakers.

Prepared testimony in support of ISO-NE's proposal to adjust the day-ahead market schedule to accommodate earlier bidding.

Prepared quarterly updates of natural gas pipeline infrastructure and market developments affecting New York State.

Retained as Agent by the New Jersey Board of Public Utilities (BPU) to administer the Long-Term Capacity Agreement Pilot Program (LCAPP) to develop 2,000 MW of new capacity; responsible for managing bidder communications and process administration.

Assessed natural gas pipeline infrastructure in the New York Control Area in light of changing supply patterns, identified peak day gas demand for electric generation, and evaluated impacts of postulated contingency events.

Designed and administered the procurement of energy, capacity, renewable energy credits and long-term renewable resources for the Ameren Illinois Utilities on behalf of the Illinois Power Agency (IPA), including bidder communication, website design, and bid evaluation; coordinated procurement procedures with the IPA, Procurement Monitor, and Illinois Commerce Commission.

Conducted a "self-assessment" of the Unitil electric utility's response to a 2008 ice storm event in Massachusetts and New Hampshire.

Assisted in preparation of testimony on behalf of Southwest Gas Corporation before FERC regarding El Paso Natural Gas rate case proceeding.

Assisted in preparation of testimony on behalf of Calpine Energy before FERC regarding gas quality tariff provisions and interchangeability on Maritimes & Northeast.

Assessed resource options in PJM for the Maryland Public Service Commission's assessment of technology and contract options.

Administered the procurement of energy, capacity and renewable energy credits on behalf of the Ameren Illinois Utilities, including bidder communication, website design and bid evaluation. Implemented procurement procedures in association with the Procurement Monitor and Illinois Commerce Commission.

Conducted a two-phase study of potential onshore and offshore wind generation in New England for ISO-NE. Provided assistance to ISO-NE for preparation of the Regional System Plan.

Managed Taunton Municipal Lighting Plant's 2007 RFP for natural gas supply, including responsibility for bidder communication and website design.

Conducted a hydraulic study for the MA Department of Energy Resources of New England's interstate gas pipelines to determine the required facility improvements in eastern Massachusetts to accommodate one or two new offshore LNG facilities.

Conducted analysis of Gas Transmission Northwest pipeline operations and rate structures on behalf of Avista Corporation, Cascade Natural Gas Corporation, Northwest Natural Gas Company, Portland General Electric Company, and Puget Sound Energy, Inc. in FERC rate case.

Assessed facility requirements on Transco to serve incremental firm transportation requirements related to the repowering of generation plants on Long Island for the Long Island Power Authority (LIPA).

Conducted analysis of El Paso Natural Gas pipeline operations and rate structures on behalf of Competitive Access Now Group, composed of several southwest market participants in FERC rate-making proceeding.

Assessed Canadian and U.S. transportation options to serve the Caithness combined cycle plant on behalf of LIPA.

Provided LIPA with commercial support regarding local imbalance resolution and transportation rights to serve power plants on Long Island resulting from National Grid's acquisition of KeySpan Energy.

Conducted market assessment of the divested Calpine generation assets in New England on behalf of prospective investors.

Analyzed the impacts of Hurricanes Katrina and Rita on Gulf Coast gas production, gathering and processing facilities in order to assess the availability of gas supply in the winter of 2005/06 for ISO-NE, NYISO and PJM.

Conducted steady-state and transient hydraulic modeling of pipeline infrastructure for PJM, including gas-side and electric-side contingencies.

Assessed adequacy of Dominion's pipeline network to meet Cornell University's incremental gas requirements for a new cogeneration plant, including hydraulic analysis of requisite system improvements. Supported Cornell's efforts to negotiate a Transportation Service Agreement with Dominion. Evaluated gas supply options and pricing arrangements at Dominion South Point versus North Point.

Performed flow balance and pressure/flow simulation modeling of Tennessee Gas Pipeline in Pennsylvania, New York and New England in support of litigation proceedings.

Supported technical consulting services facilitating the solicitation and sale of 180 MW of unit contingent power from a coal-fired PURPA project in PJM, including preparation of the RFQ, answering bidder questions, and evaluating bids.

Prepared a detailed map of the natural gas infrastructure in New England, including interstate pipelines, power plants, and LDC service territories.

Supported preparation of a FERC application for CPCN, supporting exhibits and market study for a LNG facility and an associated interstate pipeline.

Conducted market / infrastructure research and provided modeling support to update the New England steady-state pipeline model following the January 2004 cold snap.

Provided support for development of detailed integrated models of interstate natural gas pipeline systems serving the PJM, ISO-NE, NYISO and IMO control areas.

Provided infrastructure mapping and modeling support in conjunction with an RFP for provision of up to 600 MW of generation and transmission capacity. Performed research on regional load and capacity data and market analysis of generation bidding strategies.

Provided analytical support and database management for energy market analysis, price forecasting in simulation models and risk management assignments.

PRIOR ASSIGNMENTS

Conducted legislative and policy analysis research focused on the energy industry for the Northeast-Midwest Coalition Congressional and Senate staff.

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
S.B. Chemical Engineering, June 2003

INDUSTRY PUBLICATIONS AND PRESENTATIONS

"Analysis Of Gas / Electric Integration And Coordination In The Eastern Interconnection Of The United States And Canada," INFORMS 2016 Annual Meeting, Nashville, Tennessee, November 2016.

"Pipeline to Reliability," IEEE Power & Energy, Volume 12, Number 6, December 2014.

"Coal Gasification as an Alternate Energy Source," International District Energy Association 92nd Annual Conference, Las Vegas, Nevada, June 2001.

Testimony Experience of Richard L. Levitan (Partial)

Federal Energy Regulatory Commission

New York City Generators (New York Independent System Operator
Docket No. ER11-2224-000

Southwest Gas Co. (El Paso Natural Gas)
Docket No. RP05-422-000
Docket No. RP08-426-000

Pan Alberta Gas
Docket Nos. RP94-149-000, RP94-145-000

Con Edison Co.
Case No. 94-E0334

Con Edison and Central Hudson Gas & Electric (Information Disclosure)
Docket No. EL94-45-001

Arizona Directs (El Paso Natural Gas)
Docket Nos. RP88-44-000, RP95-363-000, RS92-60-000, et al

Northern Municipal Distributors Group (Northern Natural Gas Co.)
Docket No. RS92-8-000

New England Cogeneration Association (Northeast Utilities)
Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000, EL90-9-000

Northern Nevada Industrial Gas Users (Paiute Pipeline Co.)
Docket Nos. RP88-227-000, PL89-2-000

East-of-California Customer Group (Mojave Pipeline Co.)
Docket Nos. CP85-437-000, CP86-197-000

Dome Petroleum Ltd. (Cochin Pipeline Co.)
Docket No. IS85-13-000

Endicott Pipeline Co. (British Petroleum, Exxon, UNOCAL, Amoco)
Docket No. IS87-36-000

Connecticut Public Utilities Regulatory Authority
(formerly Department of Public Utility Control)

Wholesale Procurement of Standard Service and Last Resort Service
United Illuminating Company (multiple rounds)

Connecticut Light & Power Company (multiple rounds)
Docket No. 06-01-08PH02

Long Term Contracts for Standard Service
Docket Nos. 06-01-08RE01, 06-01-08RE03

Peaker Generation
Docket Nos. 07-08-24, 08-01-01

Integrated Resource Planning
Docket No. 10-02-07

New York Public Service Commission

Consolidated Edison Co. (nine dockets)
Docket No. 94-E0334

Orange & Rockland (three dockets)

New Jersey Board of Public Utilities

Orange & Rockland (three dockets)

GPU Energy

Long-Term Capacity Agreement Pilot Program
Docket No. EO11010026

Hawaii Public Utility Commission

The Gas Company of Hawaii
Docket No. 6617

Maryland Public Service Commission

Eastalco Aluminum Company
Case No. 7878

Massachusetts Department of Public Utilities

Enron Capital & Trade
Docket No. D.P.U. 97-94

Michigan Public Service Commission

Wisconsin Electric Power Company, d/b/a We Energies
Case No. U-16366

New Hampshire Public Utilities Commission

Public Service Company of New Hampshire
Case DE 10-261

Enron Energy Services
Docket No. D.T.E. 97-251

Rhode Island Public Utilities Commission

Enron Energy Services
Docket No. 2637

Public Service Commission of Ohio

West Ohio Gas Co.
Docket No. 85-0020-GA-GCR

Bonneville Power Administration

Intalco Aluminum Co.
Docket No. 95-420-C

California Public Utilities Commission

Pacific Gas & Electric Co.
Case No. 85-20-Ga-GCR

Southern California Edison Co. (multiple rounds)

Indiana Public Service Commission

Southern Indiana Gas & Electric Co.
Case Nos. 35780-S4, 35780-S8

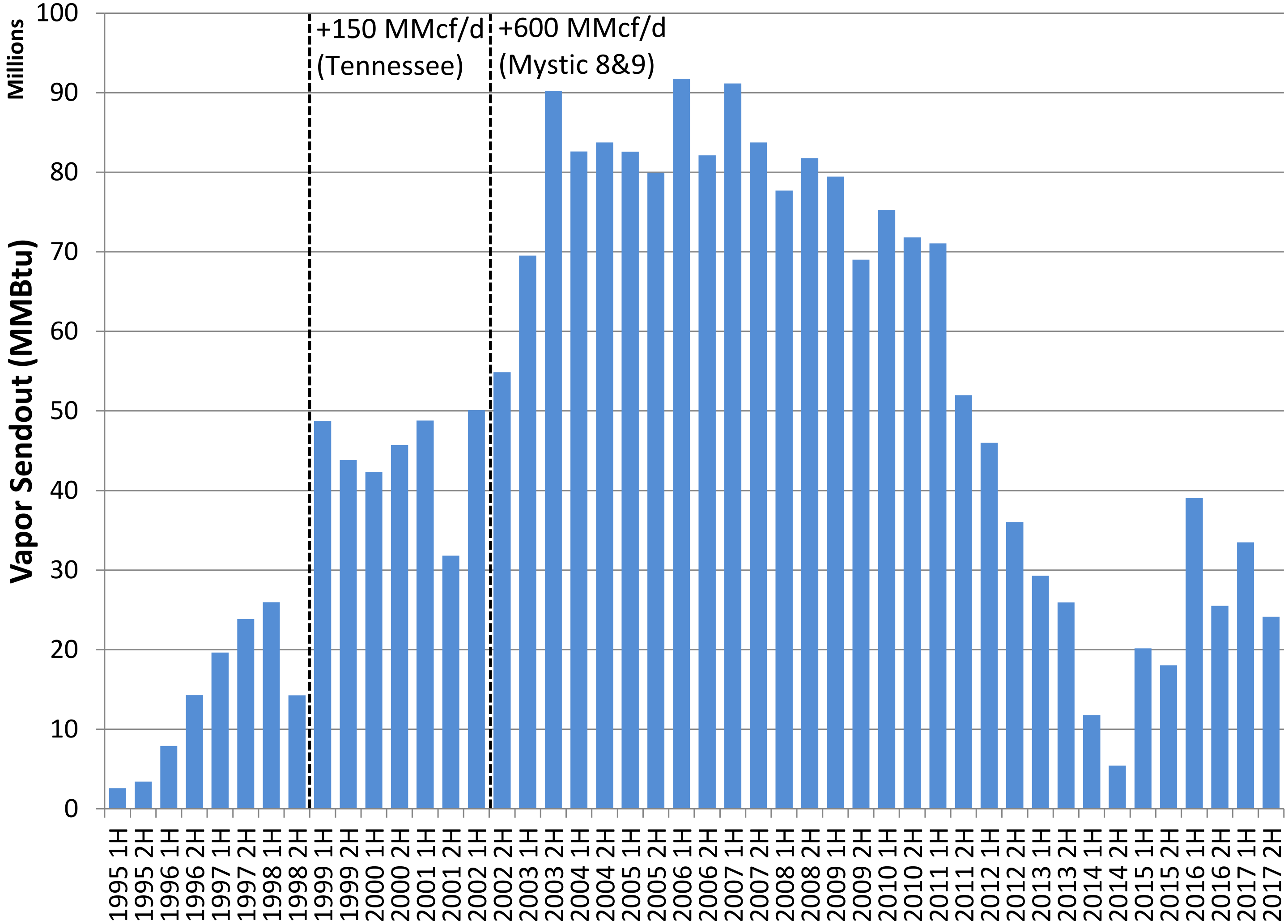
Régie De L'Énergie du Québec

L'Association des Industries Forestières du Québec
Docket No. D.P.U. 96-25

United States District Court Western District of Washington at Seattle

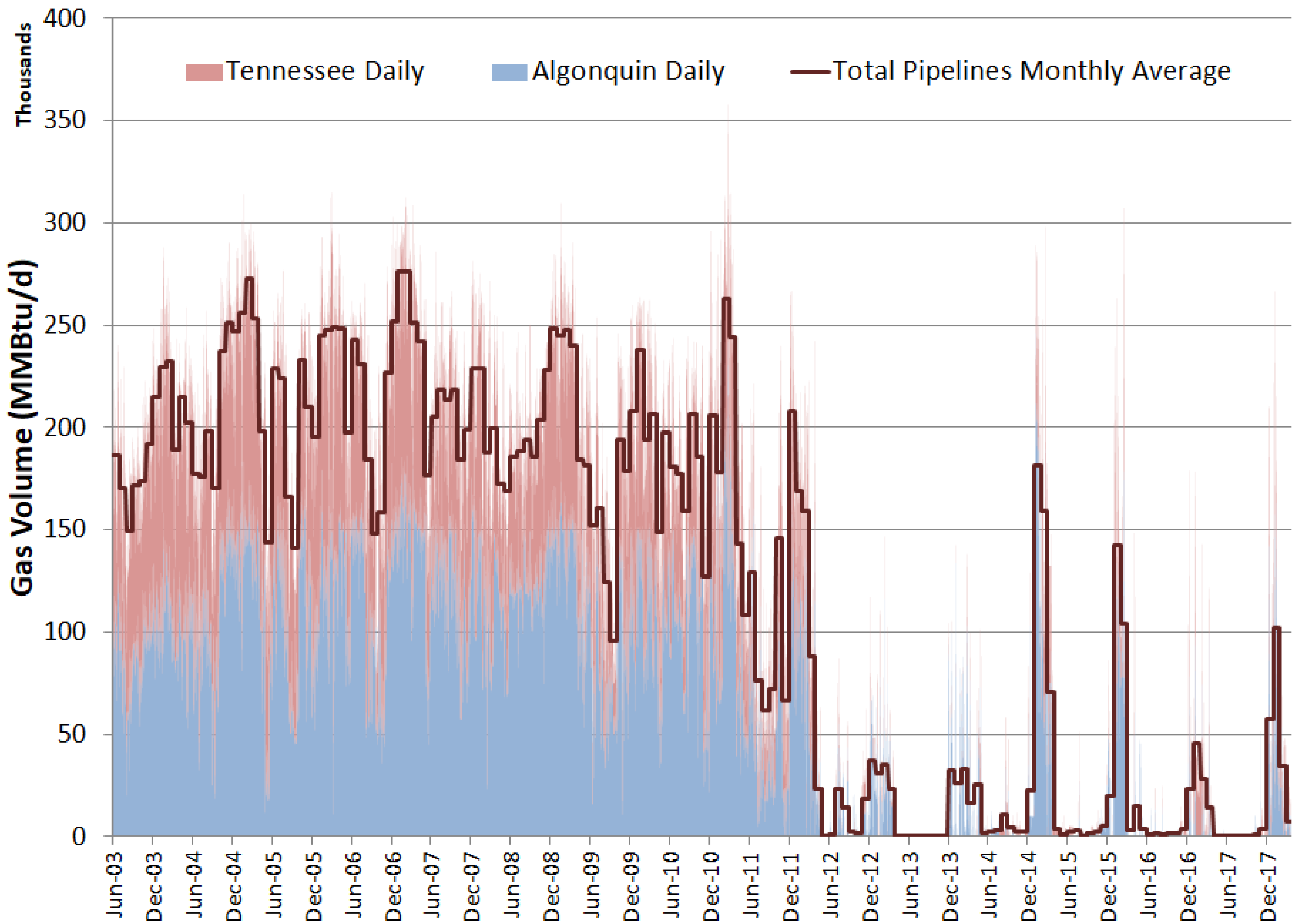
Puget Sound Energy
Docket No. C95-1833R

Distrigas Vapor Sendout History



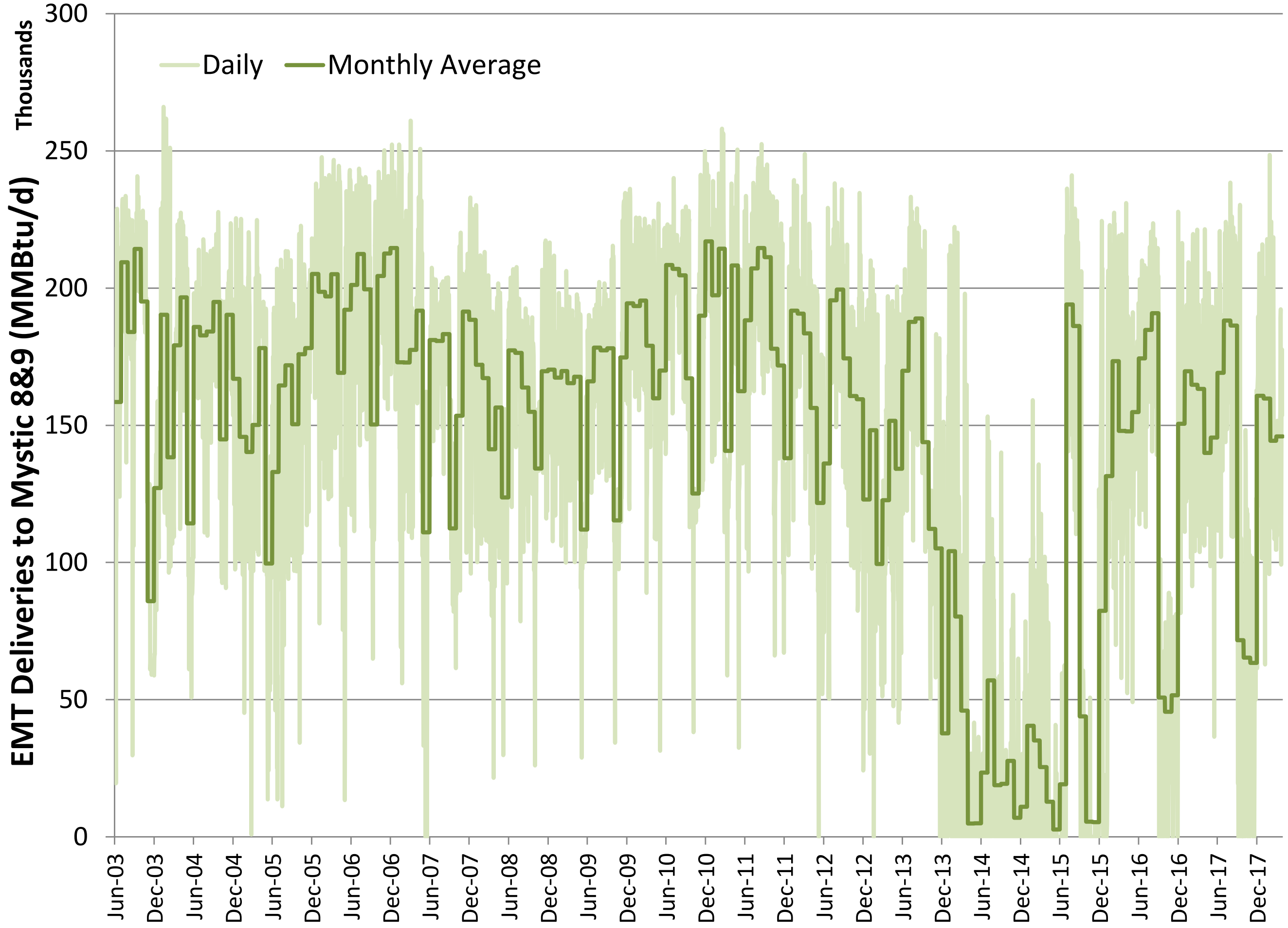
Source: Semi-Annual Operational Reports filed in FERC Docket No. CP70-196

Distrigas Sendout History to Algonquin and Tennessee



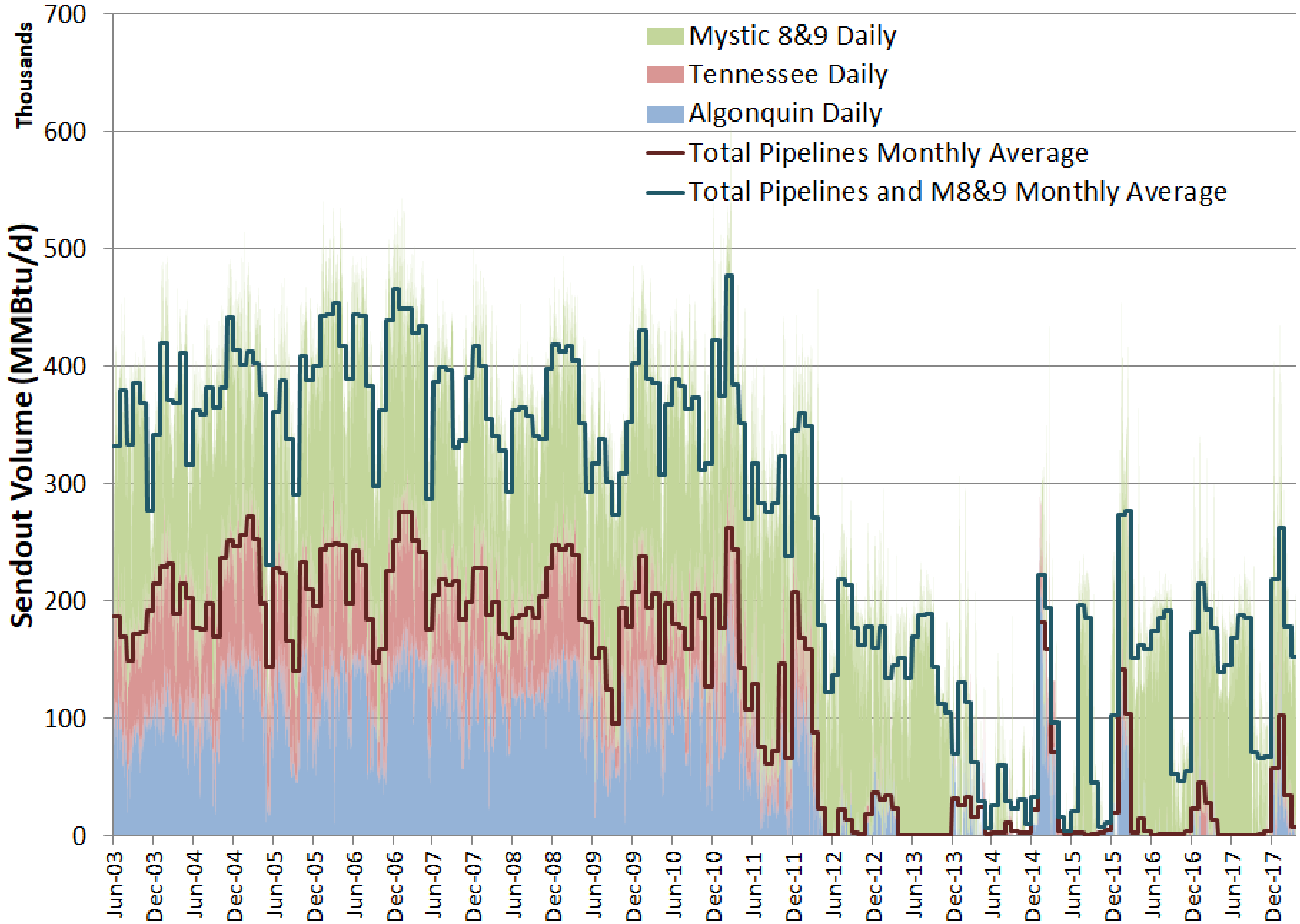
Sources: Algonquin EBB Operationally Available Capacity, Tennessee EBB Operationally Available Capacity, PointLogic Energy

Distrigas Sendout History to Mystic 8&9



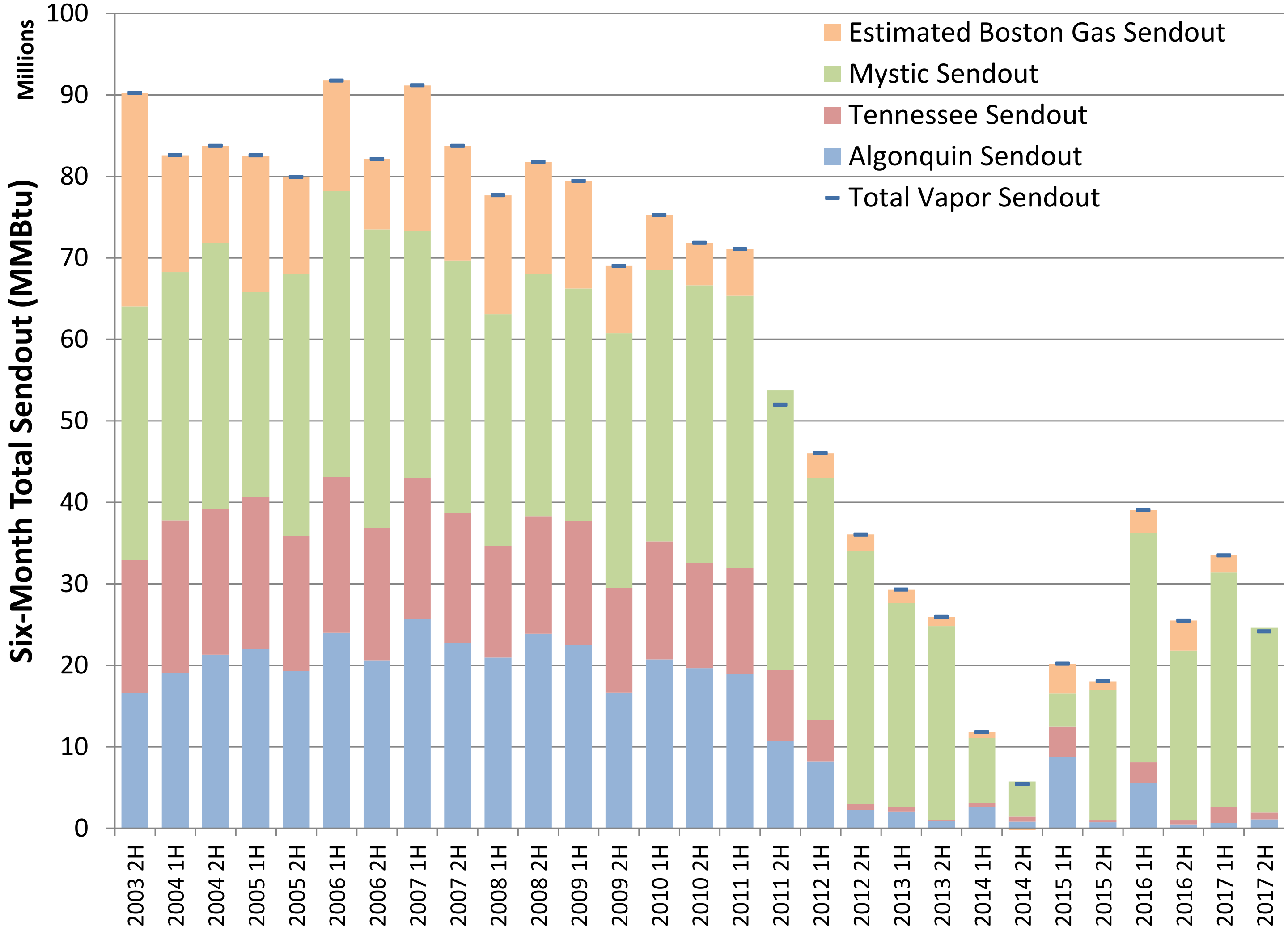
Sources: U.S. EPA Clean Air Markets Program database (June 2003 to December), non-public data provided by ISO-NE (January to March 2018)

Distrigas Sendout History to Algonquin, Tennessee and Mystic 8&9



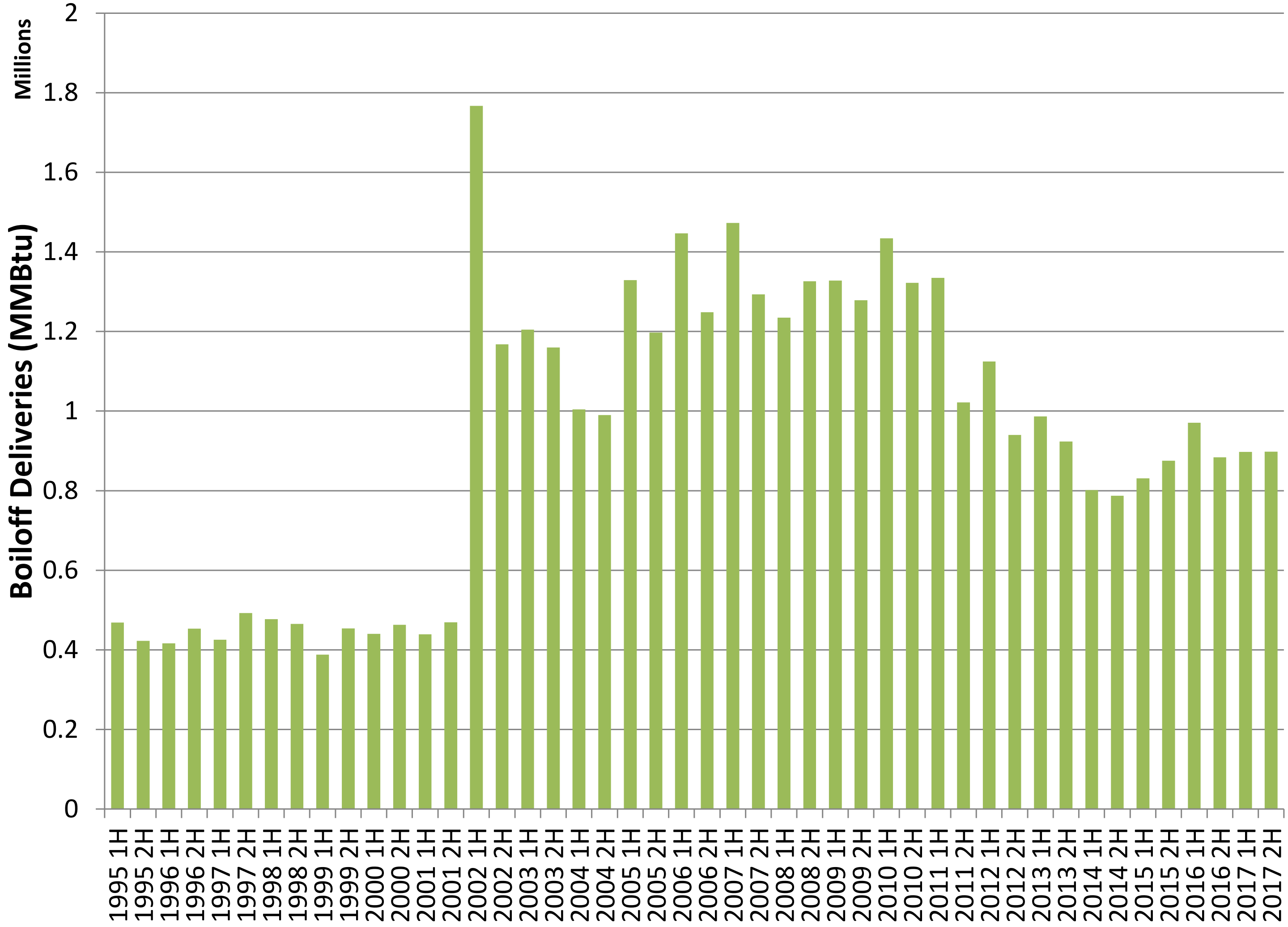
Sources: See Exhibit No. ISO-2.5 and Exhibit No. ISO-2.6

Distrigas Estimated Vapor Sendout History to Boston Gas



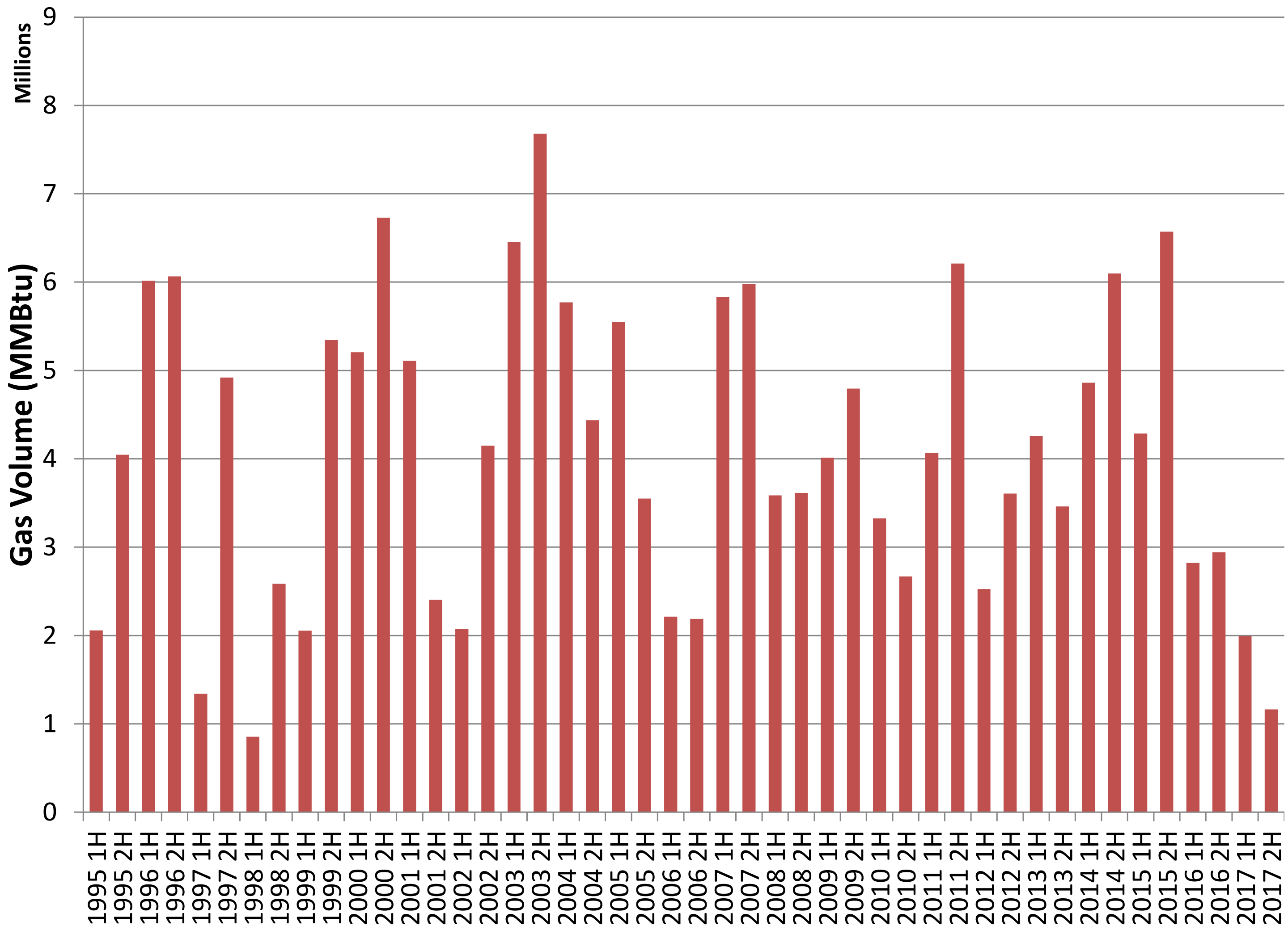
Sources: See Exhibit No. ISO-2.4, Exhibit No. ISO-2.5 and Exhibit No. ISO-2.6

Distrigas Boiloff Deliveries History



Source: Semi-Annual Operational Reports filed in FERC Docket No. CP70-196

Distrigas Liquid Sendout History



Source: Semi-Annual Operational Reports filed in FERC Docket No. CP70-196

Historical Distrigas's Going-Forward Costs in 2006-08

Operational Expenses	Year			2006-2008 Avg
Item	**2006**	**2007**	**2008**	
LNG Processing Terminal Labor and Expenses	$ 2,001,005	$ 2,545,840	$ 2,107,067	$ 2,217,971
Fuel	$ 17,445,774	$ 16,380,112	$ 21,681,901	$ 18,502,596
Power	$ 3,977,707	$ 5,042,531	$ 6,046,887	$ 5,022,375
Rents	$ 627,342	$ 257,996	$ 69,743	$ 318,360
Gas Losses	$ 101,969	$ (2,350,396)	$ (5,785,069)	$ (2,677,832)
Other Expenses	$ 2,405,995	$ 2,640,974	$ 2,874,225	$ 2,640,398
Total Operation	$ 26,559,792	$ 24,517,057	$ 26,994,754	$ 26,023,868
Maintenance				
Supervision and Engineering	$ 112,777	$ 149,914	$ 87,955	$ 116,882
Structures and Improvement	$ 115,925	$ 941,519	$ 1,233,576	$ 763,673
LNG Processing Terminal Equipment	$ 3,417,835	$ 2,161,438	$ 2,567,027	$ 2,715,433
LNG Transportation Equipment		$ -	$ -	$ -
Measuring and Regulating Equipment	$ 52,731	$ 82,890	$ 109,883	$ 81,835
Compressor Station Equipment	$ 30,000	$ 106,733	$ 83,340	$ 73,358
Communication Equipment	$ 9,805	$ 6,609	$ 13,877	$ 10,097
Other Equipment	$ 63,559	$ 65,741	$ 7,480	$ 45,593
Total Mainenance	$ 3,802,632	$ 3,514,844	$ 4,103,138	$ 3,806,871
Administration and General Expenses	$ 20,619,272	$ 27,042,416	$ 26,361,472	$ 24,674,387
Total LNG Terminalling and Processing	$ 50,981,696	$ 55,074,317	$ 57,459,364	$ 54,505,126

Real Estate Taxes	Year			2006-2008 Avg
Item	**2006**	**2007**	**2008**	
Real Estate Taxes	$ 4,954,940	$ 3,632,422	$ 3,886,565	$ 4,157,976

Gas Plant in Service	Year			
Item	**BOY 2006**	**EOY '06 BOY '07**	**EOY '07 BOY '08**	**EOY 2008**
Storage Plant	$ 126,820	$ 126,820	$ 126,820	$ 126,820
Land and Land Rights	$ 2,702,818	$ 5,552,818	$ 5,551,844	$ 5,551,844
Structures, Communications, Other	$ 18,229,358	$ 22,282,484	$ 24,927,932	$ 26,980,671
LNG Processing Terminal Equip	$ 252,730,488	$ 256,354,897	$ 257,272,420	$ 257,272,420
General Plant	$ 4,344,100	$ 7,857,921	$ 8,127,975	$ 8,326,387
Total Gas Plant in Service	$ 278,133,584	$ 292,174,940	$ 296,006,991	$ 298,258,142
	2006	**2007**	**2008**	**2006-2008 Avg**
Capex (EOY-BOY)	$ 14,041,356	$ 3,832,051	$ 2,251,151	$ 6,708,186

Source: Distrigas FERC Form 2 2006-08

Data in nominal dollars unless otherwise noted

Forecast of Distrigas's Going-Forward Costs in 2022-24 with and without Mystic 8&9

Forecast of EMT Going-Forward Costs with Mystic 8&9								
		2022		2023		2024		2022-2024 Avg
Fuel & Pwr ($/Dth)	$	0.08	$	0.08	$	0.09	$	0.08
LNG Volume (MDth)		54,900		54,900		54,900	$	54,900
Fuel & Power	$	4,256,176	$	4,506,010	$	4,728,134	$	4,496,773
Non-Fuel &Power	$	3,243,862	$	3,308,739	$	3,374,914	$	3,309,172
Total Operation	$	7,500,038	$	7,814,749	$	8,103,048	$	7,805,945
Total Maintenance	$	4,941,766	$	5,040,601	$	5,141,413	$	5,041,260
Admin and Gen'l Exps	$	32,030,252	$	32,670,857	$	33,324,274	$	32,675,128
Real Estate Taxes	$	5,397,541	$	5,505,492	$	5,615,601	$	5,506,211
Capital Expenditures	$	8,708,013	$	8,882,174	$	9,059,817	$	8,883,335
Total Going-Fwd Costs	$	58,577,610	$	59,913,873	$	61,244,154	$	59,911,879
LNG Volume (MDth)		56,030		56,030		56,030	$	56,030
Breakeven ($/Dth)	$	1.05	$	1.07	$	1.09	$	1.07

Forecast of EMT Going-Forward Costs without Mystic 8&9								
		2022		2023		2024		2022-2024 Avg
Fuel & Pwr ($/Dth)	$	0.08	$	0.08	$	0.09	$	0.08
LNG Volume (MDth)	$	18,666	$	18,666	$	18,666	$	18,666
Fuel & Power	$	1,447,100	$	1,532,043	$	1,607,566	$	1,528,903
Non-Fuel & Power	$	3,243,862	$	3,308,739	$	3,374,914	$	3,309,172
Total Operation	$	4,690,962	$	4,840,782	$	4,982,479	$	4,838,075
Total Maintenance	$	4,941,766	$	5,040,601	$	5,141,413	$	5,041,260
Admin and Gen'l Exps	$	32,030,252	$	32,670,857	$	33,324,274	$	32,675,128
Real Estate Taxes	$	5,397,541	$	5,505,492	$	5,615,601	$	5,506,211
Capital Expenditures	$	8,708,013	$	8,882,174	$	9,059,817	$	8,883,335
Total Going-Fwd Costs	$	58,577,610	$	59,913,873	$	61,244,154	$	59,911,879
LNG Volume (MDth)		18,666		18,666		18,666	$	18,666
Breakeven ($/Dth)	$	3.14	$	3.21	$	3.28	$	3.21

Source: Distrigas FERC Form 2 2006-08

Data in nominal dollars unless otherwise noted