UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)	Docket Nos. EL18-182-000
	)	ER20-1567-000

PROTEST OF THE NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

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Pursuant to Rule 211 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.211 (2019), the New England States Committee on Electricity ("NESCOE")[1] files this protest in response to ISO-NE's April 15, 2020 filing in this proceeding (the "ISO-NE Filing").[2] On July 2, 2018, the Commission issued an order directing ISO-NE to file long-term revisions to its market rules "to address specific regional fuel security concerns."[3] NESCOE's protest is supported by the testimony of

[1] NESCOE is the Regional State Committee for New England. It is governed by a board of managers appointed by the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont and is funded through a regional tariff that ISO New England Inc. ("ISO-NE") administers. ISO-NE is New England's Independent System Operator ("ISO") and Regional Transmission Organization ("RTO"). NESCOE's mission is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest possible price over the long-term, consistent with maintaining reliable service and environmental quality. NESCOE filed a timely motion to intervene in the above referenced dockets on July 6, 2018 and April 20, 2020, respectively.

[2] ISO New England Inc., Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems, Docket Nos. EL18-182-000 and ER20-1567-000 (filed April 15, 2020); Notice of Combined Filings #2, Docket No. ER20-1567-000 (April 15, 2020); Errata Notice Extending Comment Period, Docket No. ER20-1567-000 (April 16, 2020). Capitalized terms not defined in this filing are intended to have the meaning given to such terms in the ISO-NE Transmission, Markets and Services Tariff (the "Tariff"). Section III of the Tariff is known as "Market Rule 1."

[3] *ISO New England Inc.*, 164 FERC ¶ 61,003 at P 2 (2018) ("July 2018 Order"). The Commission's directive regarding long-term Tariff revisions is discussed in Section III.A.1 below. The July 2018 Order also required ISO-NE to file Tariff changes implementing a short-term, cost-of-service mechanism to address fuel security concerns. July 2018 Order at P 2. The Commission accepted ISO-NE's proposed short-term mechanism in its December 3, 2018 order. *ISO New England Inc.*, 165 FERC ¶ 61,202 (2018) ("December 2018 Order"). Alternatively, the July 2018 Order provided ISO-NE with the option of demonstrating "cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both filings is not necessary." July 2018 Order at PP 2, 55. ISO-NE did not make such a filing to demonstrate that Tariff revisions were unnecessary.

James F. Wilson, appended as Attachment A ("Wilson Testimony"), and the testimony of Denis Bergeron, appended as Attachment B ("Bergeron Testimony"). This protest represents the collective position of the six New England states.

The ISO-NE Filing proposes an Energy Security Improvements ("ESI") program, a suite of new day-ahead reserve products designed to procure options on real-time energy ("ESI Proposal").[4] The ISO-NE Filing includes a description of a New England Power Pool ("NEPOOL") supported alternative compliance proposal ("NEPOOL Proposal").

On April 22, 2020, NEPOOL filed in support of its alternative proposal ("NEPOOL Filing").[5] The NEPOOL Proposal maintains the core ESI design, making targeted changes intended to achieve a better balance between the reliability benefits ISO-NE seeks to achieve and the costs consumers would incur.[6] The NEPOOL Filing explains why adoption of its proposal would not undermine the fuel security objectives that ISO-NE seeks to achieve through ESI.[7]

At the outset, NESCOE notes its appreciation to the Commission for granting its request for an extension of the deadline for ISO-NE to file its long-term market design.[8] The work and

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4 In a footnote, ISO-NE asks that the Commission consider its filing under section 205 of the Federal Power Act ("FPA") and accept it as just and reasonable if the Commission determines that any part of its proposed solution is "outside the scope of its directive" in the July 2018 Order. ISO-NE Filing, Transmittal Letter ("Transmittal Letter"), at n. 1. In a section 205 filing, ISO-NE bears the burden of establishing that its "rate adjustment . . . is lawful." *Emera Maine v. FERC*, 854 F.3d 9, 24-25 (D.C. Cir. 2017) ("*Emera*") (emphasis removed). To the extent the Commission undertakes any such review of the ISO-NE Filing under section 205, NESCOE protests the filing pursuant to 16 U.S.C. § 824d. ISO-NE fails to show that its proposal is just and reasonable for the reasons set forth in this protest.

5 New England Power Pool Participants Committee, Comments in Support of NEPOOL-Approved ESI Proposal, Docket Nos. EL18-182-000 and ER20-1567-000 (filed April 24, 2020).

6 *See id.* at 2-3.

7 *Id.* at 15-29. ISO-NE notes that while it has referred to "fuel security" in the past, it now refers to New England's risks as an "energy security" problem. ISO-NE Filing at n. 3. For convenience, and because the July 2018 Order provides directives regarding "fuel security," this protest uses both phrases synonymously but generally refers to a "fuel security" risk.

8 *See ISO New England Inc.*, Notice of Extension of Time, Docket No. EL18-182-000, Aug. 30, 2019 ("Second Extension Order"); Motion of the New England States Committee on Electricity for Extension of Time, Docket No. EL18-182-000 (filed July 31, 2019).

discussion undertaken as a result of the extension appear to have narrowed the issues that will come before the Commission in this phase of the proceeding. Additionally, while NESCOE and ISO-NE have divergent views on the legal and policy issues that the ESI Proposal presents—differences which have real implications for consumers and the future of our power system—NESCOE recognizes and appreciates the steady efforts of ISO-NE's technical staff in responding to questions over a lengthy and complex design development process.

I. INTRODUCTION

NESCOE opposes the ESI Proposal. It fails in two fundamental ways. First, ISO-NE proposes an unconventional call option approach that unilaterally changes the scope of the July 2018 Order. Instead of squarely addressing winter fuel security, the ISO-NE Filing goes well beyond the Commission's compliance directives and proposes a novel and untested year-round program for improving price formation.

Second, the ESI Proposal would produce an unjust and unreasonable replacement rate. ISO-NE's approach (i) is highly vulnerable to producing uncompetitive outcomes without a demonstrated ability to mitigate market power effectively, (ii) is an overly expensive option for satisfying reliability standards, (iii) overcharges consumers through substantial incentives that fail to account for diminishing marginal reliability value and are grossly disproportionate to fuel holding costs, (iv) generally procures more reserves than the system needs, and (v) imposes an unconventional approach to procuring ancillary services that exposes consumers to additional unwarranted costs. To state it plainly, ESI is a bad bargain.

NESCOE is deeply concerned about the exercise of market power in connection with ESI and the potential for physical and economic withholding. ISO-NE has yet to complete a market power assessment for ESI and has deferred that work. Yet, as the Wilson Testimony highlights, there are material open questions regarding whether market power could ever be effectively mitigated given ESI's unique energy call option approach, which no other RTO appears to employ.[9] Consistent with Commission and court precedent, the Commission should not approve the ESI Proposal without first determining that market power can be effectively mitigated.

Even if ISO-NE could effectively address market power concerns, the ESI Proposal is still not just and reasonable. It overcharges consumers in violation of the FPA and Commission precedent. ISO-NE disregards consumer interests by ignoring the diminishing reliability value that ESI provides as the quantity of options purchased increases. Moreover, as Potomac Economics, ISO-NE's External Market Monitor ("EMM") has noted, the ESI program procures reserves at a level that is "extremely likely to exceed the amount that would be converted to energy in real-time."[10] ISO-NE is using "a tank to block a mouse hole,"[11] proposing an oversized response to the "misaligned incentives" problem it identifies.

ISO-NE's own analysis puts this excess in high definition.[12] Under ESI, oil-fired and dual fuel resources are projected to earn "average incremental payments that . . . *far outweigh* the additional costs from purchasing and holding additional fuel."[13] The ISO-NE Filing highlights the revenue opportunities for dual fueled combined cycle generators. Those resources would "on average, incur an additional $14 per [megawatt ("MW")] in holding costs during a stressed

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[9] For brevity, this protest uses "RTO" to refer to ISOs/RTOs.

[10] Memorandum from David B. Patton and Pallas LeeVanSchaick of Potomac Economics to ISO New England and NEPOOL Markets Committee, NESCOE Proposal to Raise the Strike Price of Energy Call Options, Mar. 20, 2020 ("EMM Memo"), at 2 (citation omitted), available at https://www.iso-ne.com/static-assets/documents/2020/03/a2_b_vi_emm_memo_re_nescoe_strike_price_amendment.pdf.

[11] *Dominion Resources, Inc. v. FERC*, 286 F.3d 586, 593 (D.C. Cir. 2002) ("*Dominion*").

[12] Attachment C of the ISO-NE Filing includes an April 2020 report from the Analysis Group, Inc. ("Analysis Group"): Energy Security Improvements Impact Analysis ("Impact Assessment"). ISO-NE engaged the Analysis Group "[t]o evaluate the efficacy and cost of" the ESI Proposal. ISO-NE Filing at 5.

[13] Transmittal Letter at 30 (emphasis added) (citing Impact Assessment at Section IV.A.1.c).

winter with frequent cold snaps" while receiving on average "an additional $5,591 per MW from providing energy and ancillary services" through ESI.[14] That translates to a net revenue of $5,577 per MW, an incentive that is almost 400 times greater than the incremental cost of holding fuel.[15] While the results vary by resource type and across a range of scenarios,[16] they demonstrate convincingly the disproportionate level of incentives ISO-NE has fashioned, suggesting a tunnel focus on generator revenues that is divorced from consumer cost considerations and its own mission statement.[17] The Commission cannot ignore this imbalance.

The ESI Proposal is redolent of ISO-NE's intended approach to costs in the last winter reliability program, where the Commission declined to accept ISO-NE's proposal because the costs of the program were not commensurate with the reliability provided.[18] With ESI, ISO-NE is stepping on the same rake twice. The ESI Proposal would, according to ISO-NE's analysis, expose consumers to hundreds of millions of dollars each year.[19] ISO-NE's failure to demonstrate that ESI's high premium is worth the value to consumers places the Commission in a box of ISO-NE's making: reasoned decision making requires an explanation of how ESI's

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14 *Id.*

15 *See id.*

16 *See* Impact Assessment at 52-53, including Tables 11-13.

17 *See* Tariff, Section I.1.3. (stating that ISO-NE's mission includes "open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services (including Operating Reserves) that are (i) economically efficient and *balanced between buyers and sellers*," paying suppliers a "fair value," and providing "for an equitable allocation of costs, benefits and responsibilities among market participants.") (emphasis added).

18 *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,190 at P 47 (2015) ("Winter Program III Order"), *order on reh'g*, 154 FERC ¶ 61,133 (2016).

19 *See* Impact Assessment at 45, 83. Total net day-ahead ancillary services costs and forecast energy requirement ("FER") payment costs range from $183 million to $466 million per year for the central cases across a range of winter and non-winter conditions. Hypothetically avoided higher energy prices are not included in these consumer cost estimates. As discussed below, the Impact Assessment may substantially understate the consumer cost implications of the program.

purported benefits are balanced against its costs, yet ISO-NE provides no record upon which the Commission can rely to explain how it will weigh these considerations.

The ESI Proposal attempts to improve price formation, rather than squarely address the Commission's fuel security directives. NESCOE supports, and has a long history of supporting, market rule changes that seek to align price signals with the value of the services that resources provide in ISO-NE's wholesale markets. Such changes, when appropriately designed, can be mutually beneficial for resources and consumers. But consumer dollars should only be spent when the resulting rates are just and reasonable, requiring a meaningful consideration of both costs and benefits. As filed, the ESI Proposal does not provide value commensurate with the substantial charges that consumers would likely incur. Moreover, ISO-NE's unconventional approach exposes consumers to additional unnecessary costs.

The shortcomings of the ESI Proposal are too many and too material. The Commission cannot find that it meets the requirements of the July 2018 Order or the FPA's mandate that replacement Tariff revisions produce just and reasonable rates.[20] NESCOE respectfully requests that the Commission reject the ISO-NE Filing.

If the Commission does not reject the ISO-NE Filing, NESCOE respectfully requests that the Commission accept it only subject to further compliance and that it direct changes to the ESI Proposal to provide baseline consumer protections that the ISO-NE approach lacks. Specifically, the Commission should direct ISO-NE to adopt the revisions reflected in the NEPOOL Proposal, which would: (i) calculate the Replacement Energy Reserve ("RER") quantity only for the three winter months (December to February) and set it to zero for the nine non-winter months (March

[20] 16 U.S.C. §§ 824d(a), 824e(a); *see Advanced Energy Mgmt. Alliance v. FERC*, 860 F.3d 656, 663 (D.C. Cir. 2017) ("*Advanced Energy*"); *Emera* at 23-24.

to November), (ii) remove RER's allowance for load forecast error in each hour of the operating day, and (iii) adjust the proposed strike price with a $10 per megawatt hour ("MWh") adder in all hours.[21] None of these changes would materially reduce incentives for fuel security for the reasons discussed below and, as the NEPOOL Filing explains, a supermajority of the region's stakeholders agree with and voted to support these reasonable and targeted revisions.[22] NESCOE supports the NEPOOL Proposal as one way to mitigate some of the harm from a program that unnecessarily exposes consumers to excessive costs.

II. BACKGROUND

A. The Commission's Fuel Security Directives

In its July 2018 Order, the Commission rejected an ISO-NE petition to waive multiple Tariff provisions in connection with ISO-NE's identified need to retain two large retiring generating units in Greater Boston, Mystic Units 8 and 9, for fuel security purposes.[23] While rejecting ISO-NE's request, the Commission initiated a proceeding under section 206 of the FPA based on its preliminary finding that the Tariff may be unjust and unreasonable because it "fails to address specific regional fuel security concerns identified in the record."[24] In making its preliminary finding, the Commission pointed to two analyses that ISO-NE had undertaken prior to the petition and that ISO-NE relied upon in making its request.[25]

The first analysis, the January 2018 Operational Fuel Security Analysis ("OFSA"), "examined the effect of 23 possible future resource and fuel mix scenarios, as well as outages of

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21 *See* ISO-NE Filing at Attachments E-1 and E-2; NEPOOL Filing at 15-29.

22 *See* NEPOOL Filing at 9-10.

23 *See* July 2018 Order at P 47.

24 *Id.* at P 49.

25 *Id.*

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."[26] ISO-NE designed the OFSA "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)."[27] ISO-NE stated that the OFSA used a "wide range of scenarios . . . in order to illustrate the array of potential risks that could confront the New England power system, given fuel security concerns during winter."[28]

ISO-NE's subsequent analysis, known as the "Mystic Retirement Studies," assessed "operational risks associated with the retirement of Mystic 8 and 9 during the 2022-2023 and 2023-2024 winter periods[.]"[29] The Commission described the OFSA and the Mystic Retirement Studies as each "indicat[ing] that the loss of both Mystic 8 and 9" and an adjacent liquefied natural gas ("LNG") facility "would lead to the depletion of operating reserves and load shedding."[30]

The Commission found that the OFSA and the Mystic Retirement Studies supported its preliminary findings that the Tariff may be unjust and unreasonable and that ISO-NE's market

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[26] ISO New England Inc., Petition for Waiver, Docket No. ER18-1509-000 (filed May 2, 2018), Testimony of Peter T. Brandien on Behalf of ISO New England Inc., Ex. ISO-1 ("2018 Brandien Testimony"), at 19.

[27] *Id.*

[28] *Id.* at 21.

[29] July 2018 Order at P 5.

[30] *ISO New England Inc. and New England Power Pool Participants Committee*, 170 FERC ¶ 61,099 at P 2 (2020) ("February 2020 Order").

rules, including the pay-for-performance ("PFP") program, "might not provide a full solution to the fuel security problems" that the studies identified.[31] It directed ISO-NE either "(1) to submit within 60 days of the date of this order interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns; or (2) within 60 days of the date of this order, to show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both filings is not necessary."[32] Thus, the Commission made a preliminary determination that the existing tariff *may be* unjust and unreasonable, but it has not yet found that the existing tariff is unjust and unreasonable due to fuel security concerns.

In the December 2018 Order, the Commission accepted ISO-NE's proposed short-term Tariff revisions providing authority for ISO-NE to retain resources for fuel security for Capacity Commitment Periods 2022-2023 through 2024-2025 ("Interim Fuel Security Mechanism").[33] By operation of law, the Commission also accepted an additional stop-gap measure, known as the "Inventoried Energy Program," that ISO-NE filed to address fuel security concerns pending implementation of long-term Tariff provisions.[34]

Commission staff led a public meeting on July 15, 2019 focused on the New England region's efforts to develop long-term market design changes in response to the July 2018 Order

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[31] July 2018 Order at PP 50, 53.

[32] *Id.* at P 55.

[33] December 2018 Order at P 9; *see id.* at P 96 ("This interim solution is solely a stop-gap measure to address the fuel security challenges facing the region while ISO-NE develops its long-term market-based approach.").

[34] *ISO New England Inc.*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER19-1428-001 (Aug. 6, 2019) (unreported); ISO New England Inc., Inventoried Energy Program, Docket No. ER19-1428-000 (filed Mar. 25, 2019). On April 21, 2020, the D.C. Circuit granted a request for voluntary remand of this case so that the Commission, which now has a quorum to participate in the proceeding, can issue an order on remand and subsequent order on rehearing.

("2019 FERC Meeting"). The Commission granted two requests to extend ISO-NE's deadline for filing its long-term, market-based solution.[35]

B. Description of the ESI Proposal

ISO-NE seeks to implement three new ancillary services products through the ESI program: a Day-Ahead Energy Imbalance Reserve ("EIR"), Day-Ahead Generation Contingency Reserve ("GCR"), and Day-Ahead RER.[36] EIR is designed to provide ISO-NE with day-ahead assurance that it will have energy in real-time to cover any gap in the load purchased voluntarily day-ahead and the real-time energy forecast over any hours of the operating day.[37] GCR would use the day-ahead market to "help provide a next-day operating plan to reliably supply energy when operating conditions unexpectedly deviate from" the forecast and "provide a margin for such uncertainties."[38] The RER product is "designed to prepare the system to handle an unanticipated loss of supply, or unanticipated increase in demand, that persists for a significant (multi-hour) period of time during the operating day."[39] The ESI program is not limited to addressing winter fuel security risks and would apply in all months of the year.

The ESI Proposal provides ISO-NE with call options on energy in real-time.[40] There are three settlement features involved: "(1) a sale of the option, which occurs at the option price; (2) a pre-determined strike price; and (3) the real-time price of the energy."[41] ISO-NE sets the

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35 *ISO New England Inc.*, Notice of Extension of Time, Docket No. EL18-182-000 (Mar. 18, 2019); Second Extension Order.

36 Transmittal Letter at 34.

37 *See id.* at 34-36; ISO-NE Filing, Attachment B, Energy Security Improvements: Creating Energy Options for New England, April 15, 2020 ("ESI White Paper"), at Section 6.

38 ESI White Paper at 153; *see generally id.* at Section 7.

39 *Id.* at 153; *see generally id*. at Section 7.

40 *See* Transmittal Letter at 5, 46; ESI White Paper at 6, 58-59.

41 Transmittal Letter at 5; *see* ESI White Paper at Section 4.

strike price—representing "the maximum value" that ISO-NE, on customers' behalf, would agree to pay for the option—in advance of when "sellers specify their option offer prices and the market clears."[42] Market participation is voluntary for eligible supply resources.[43] However, a resource with a cleared option obligation that fails to provide energy in real-time "will be charged based on the price of real-time energy if that price exceeds the applicable hour's pre-determined strike price."[44]

ISO-NE's development of the ESI Proposal was guided by its identification of "three interrelated market and operations problems in the current market design that can adversely affect the efficacy and reliability of the New England power system."[45] The ISO-NE Filing summarizes the three problems:

1. Misaligned incentives: when the incentive for market participants "to take action to improve their resources' ability to provide energy supply in real-time do not align with society's interests in" that participant making energy supply arrangements.

2. Operational uncertainties: when ISO-NE is concerned that "there may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss during stressed system conditions, because the resources [ISO-NE] relies on to address such energy gaps are those most likely to suffer from the misaligned incentives problem."

3. Insufficient day-ahead scheduling: when market participants buy less energy day-ahead than ISO-NE's forecasted energy demand for the next operating day.[46]

ISO-NE states that the misaligned incentives problem "precipitates the second and third problems."[47] In designing a call option approach to address this problem, ISO-NE focused on

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[42] Transmittal Letter at 5.

[43] *Id.*

[44] *Id.*; *see* ESI White Paper at Section 4.4.

[45] Transmittal Letter at 13; *see* ESI White Paper at Section 2.

[46] Transmittal Letter at 13-14; *see* ESI White Paper at Section 2.

[47] Transmittal Letter at 13.

two objectives.[48] First, the product "must compensate the supplier sufficiently that it will be willing to incur the (up-front) costs of arranging energy supplies, whenever that would be cost-effective from the system's standpoint."[49] The second objective is ensuring that this "compensation cannot simply be a handout."[50] The energy option must have "a well-designed financial consequence tied to whether or not the resource provides energy, so that it will be induced to follow through and undertake arrangements that benefit the system."[51]

ISO-NE describes a number of asserted "attendant benefits" of the ESI Proposal. ISO-NE's list includes promoting innovative technologies, improving price transparency, and enhancing price formation.[52] ISO-NE also states that the ESI program "will help manage the rapid growth of renewables participating in the New England markets in the long-term."[53] Specifically, ISO-NE believes that ESI "will help the system manage the uncertainty over these resources' next-day energy production throughout the year" and "will recognize and compensate resources for reliable, flexible, and responsive attributes that help [ISO-NE] manage, and prepare for, energy supply uncertainties each day."[54]

ISO-NE has elected to use ESI as an alternative approach to satisfying certain reliability standards. The ISO-NE Filing describes various North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and ISO-NE energy

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48 *See* ESI White Paper at 81.

49 *Id.*

50 *Id.*

51 *Id.*

52 Transmittal Letter at 25-26.

53 *Id.* at 26

54 *Id.*

supply planning and reserve requirements.[55] These standards include the development of next-day operating plans "that ensure the availability of sufficient resources to meet expected energy demand (load) and reserve requirements."[56] ISO-NE discusses why it seeks to use the ESI program to meet applicable reliability requirements and how it differs from ISO-NE's existing approach and approaches in other regions.[57]

The ISO-NE Filing includes a quantitative and qualitative analysis, the Impact Assessment, to support the ESI Proposal. ISO-NE summarizes the Impact Assessment as "show[ing] that the proposed design will create strong financial incentives for resources to maintain more secure energy supplies at a modest cost to consumers when compared to all [ISO-NE] markets."[58] The Impact Assessment provides information including the expected revenues that resources would receive under the ESI program, production cost impacts, and estimated consumer cost impacts.[59]

ISO-NE describes two major undertakings related to the ESI Proposal that remained open as of its filing. First, ISO-NE has not developed a detailed approach to mitigating the exercise of market power in connection with the ESI program or proposed market mitigation rules.[60] ISO-NE states that it has commenced this "mitigation-related work, but additional time is needed to complete the required [market power assessment ("MPA")] and develop an appropriate mitigation proposal."[61] ISO-NE requests that the Commission accept the ESI Proposal

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55 ISO-NE Filing, Attachment A, Testimony of Peter T. Brandien ("Brandien Testimony"), at 6-12.

56 *Id.* at 6.

57 *Id.* at 17-30; *see* Transmittal Letter at 12, 16, 34-40, 43.

58 *Id.* at 27.

59 *See id.* at 27-34 (describing Impact Assessment methodology and results).

60 *Id.* at 70.

61 *Id.*

"conditioned upon [ISO-NE's] filing of an appropriate market power mitigation proposal supported by [ISO-NE's] MPA by the fourth quarter of 2021, and the Commission's acceptance of that filing."[62]

Second, ISO-NE anticipates working on the development of a seasonal forward market. ISO-NE is considering such a market to "further help the region procure" the ESI products and its "initial work has identified a set of conditions where a forward auction may further improve market efficiency, using a potential two-settlement design where suppliers could sell these services via a forward auction held some months in advance of the delivery period."[63] ISO-NE plans to begin detailed discussions with stakeholders in 2021 regarding a seasonal forward market, provided that the Commission has issued an order in this proceeding by ISO-NE's requested date.[64]

C. Description of the NEPOOL Proposal

The NEPOOL Proposal addresses features of the ESI Proposal that "go further than the scope of the demonstrated fuel security needs and that would impose significant, unjustified costs on consumers."[65] It modifies the ESI Proposal in three ways. NEPOOL states that none of its changes would undermine a demonstrated reliability need.[66]

First, the NEPOOL Proposal limits ISO-NE's procurement of RER to the winter period.[67] The NEPOOL Filing explains why purchasing RER in the non-winter months, at a cost as high

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62 *Id.* at 75.

63 *Id.* at 71-72.

64 *Id.* at 72.

65 NEPOOL Filing at 12.

66 *See id.* at 15-29.

67 *Id.* at 3.

as $69 million each year, is not needed for fuel security and imposes unjustified costs on consumers.[68]

Second, the NEPOOL Proposal eliminates an allowance for load forecast error that ISO-NE would reflect in the quantity of RER purchased.[69] NEPOOL states that ISO-NE's "preference to over-procure RER by accounting for [load forecast error] is vague, is not supported by any demonstrated fuel security need, and will add considerable unnecessary costs to consumers."[70] NEPOOL's expert witness estimates that, for each winter period, consumers are exposed to over $100 million in additional costs through the inclusion of load forecast error.[71] That number "would be significantly higher" if load forecast error is factored in year-round.[72]

Third, the NEPOOL Proposal adjusts the strike price through a $10/MWh adder ("Strike Price Adder").[73] While NEPOOL is generally supportive of ISO-NE's strike price concept, it proposes the Strike Price Adder "to reduce unnecessary risk to suppliers and unjustified costs to consumers, while maintaining the efficacy of the energy call option offer."[74] NEPOOL explains that adoption of the Strike Price Adder could save consumers almost $35 million per year.[75]

The NEPOOL Filing describes the development of the alternative proposal. During the stakeholder process, NESCOE sponsored three amendments that NEPOOL voted on to amend

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68 *Id.*; *see* NEPOOL Filing, Attachment 1, Affidavit of David A. Cavanaugh ("Cavanaugh Testimony"), at 9-10; NEPOOL Filing, Attachment 2, Affidavit of James G. Daly ("Daly Testimony"), at 4-7; NEPOOL Filing, Attachment 3, Affidavit of Benjamin W. Griffiths ("Griffiths Testimony"), at 9-19.

69 NEPOOL Filing at 3.

70 *Id.*; *see* Cavanaugh Testimony at 11-14; Daly Testimony at 7; Griffiths Testimony at 12-13, 21, 24-25.

71 Cavanaugh Testimony at 13-14.

72 *Id.* at 14.

73 NEPOOL Filing at 3.

74 *Id.*

75 *Id.* at 28.

the ESI Proposal.[76] The amended motion received a supermajority of regional stakeholder support, with 61.70% in favor.[77] The unamended ESI Proposal failed to achieve significant stakeholder support, receiving only 39.59% in favor.[78]

Pursuant to ISO-NE's commitment during the stakeholder process, ISO-NE included the NEPOOL Proposal as part of its own filing "for the Commission's consideration of both proposals on equal legal footing."[79] NEPOOL explains that the Commission has broad legal authority to direct ISO-NE to adopt the NEPOOL Proposal in whole or in part.[80]

III. PROTEST

The ESI Proposal addresses different problems than the July 2018 Order identified and is not just and reasonable. The ISO-NE Filing unilaterally seeks to change the scope of the Commission's directives to apply a solution outside the winter period and proposes a design to improve price formation that does not squarely address the Commission's fuel security concerns.

The ESI Proposal would also overcharge consumers for a novel and untested approach and is unlawful under the FPA.[81] ESI upends the FPA, prioritizing generator revenues over

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76 *See id.* at 11.

77 *Id.*

78 *Id.*

79 *Id.* at 2; *see id.* at 13.

80 *See id.* at 13-14.

81 *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 781 (2016) (one of the FPA's core objectives is to "protect against excessive prices") ("*EPSA*") (cleaned up); *NAACP v. FCP*, 425 U.S. 662, 666 (1976) (FPA includes "the legislative command to the Commission . . . to establish just and reasonable rates for the transmission and sale of electric energy, . . . and, consequently, to allow only such rates as will prevent consumers from being charged any unnecessary or illegal costs.") (cleaned up); *NextEra Energy Res. v. FERC*, 898 F.3d 14, 21 (D.C. Cir. 2018) ("*NextEra*") ("The Commission must protect . . . consumers from excessive rates and charges.") (cleaned up); *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1, 12 (D.C. Cir. 2015) ("*TransCanada*") ("It is indisputable that, under established ratemaking principles, rates that permit excessive profits are not just and reasonable."); *City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955) (the Commission can increase rates to promote consumer benefits, but "it must see to it that the increase is in fact needed, and is no more than needed, for the purpose."); *see Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1207 (D.C. Cir. 1987) (Starr, J., concurring) ("The Commission stands as the watchdog providing a complete, permanent and effective bond of protection from excessive rates and charges.") (cleaned up).

consumer interests.[82] The Commission cannot set a just and reasonable rate without sufficiently considering consumer charges and guarding against excessive costs. NESCOE respectfully requests that the Commission reject the ISO-NE Filing.

Alternatively, while this protest explains why the Commission is required under the FPA and its precedent to reject the ISO-NE Filing, if it does not, then NESCOE respectfully requests that the Commission accept it only subject to further compliance and direct ISO-NE to adopt the NEPOOL Proposal for the reasons discussed below.

A. The ESI Proposal Changes the Scope of the July 2018 Order and Is Not Just and Reasonable

1. The ISO-NE Filing Is Not Compliant with the Commission's Directives

a. ISO-NE Improperly Expands the Commission's Directives to Non-Winter Months

The July 2018 Order directed ISO-NE to establish a long-term, market-based solution to address *specific* regional fuel security concerns.[83] Those specific concerns relate to the winter period. The Commission's directives came in response to ISO-NE's petition to retain Mystic Units 8 and 9 given "the region's fuel security challenges in winter."[84] In invoking its section 206 authority, the Commission relied on the OFSA and the Mystic Retirement Studies, which identified operational risks solely in the winter.[85] The July 2018 Order cites to no other analysis,

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[82] *See Xcel Energy Servs. Inc. v. FERC,* 815 F.3d 947, 952 (D.C. Cir. 2016) ("It is long-established that the primary aim [of the FPA] is the protection of consumers from excessive rates and charges.") (cleaned up); *Maine Public Service Co. v. FPC*, 579 F.2d 659, 668 (1st Cir. 1978) (stating that the FPA requires the Commission to "put the welfare of consumers first" in considering electric wholesale charges); *Pac. Gas and Electric Co.; San Francisco Bay Area Rapid Transit District v. Pac. Gas and Electric Co.*, 154 FERC ¶ 61,025 at P 10 (2016) ("The primary purpose of the [FPA] is the protection of customers from excessive rates and charges.") (quoting *Southwestern Elec. Power Co*., 39 FERC ¶ 61,099 at 62,293 (1987)).

[83] July 2018 Order at PP 2, 49.

[84] Transmittal Letter at 9 (emphasis added).

[85] July 2018 Order at PP 49-55; *see id.* at P 5 (describing the Mystic Retirement Studies as focused only on two winter periods, 2022-2023 and 2023-2024) and 2018 Brandien Testimony at 19-21 (describing how the OFSA assessed the system operational risks under different scenarios over the 2024-2025 winter).

or any area of risk other than winter fuel supply, to support the Commission's findings about regional fuel security and its directives to ISO-NE. There is, therefore, no basis to believe that the scope of the Commission's directives in the July 2018 Order is broader than requiring Tariff revisions to address fuel security problems in the winter period.

The Commission's proceeding on the Interim Fuel Security Mechanism confirms the scope of this directive. These short-term rules allow ISO-NE to provide a cost-of-service agreement to resources ISO-NE identifies as necessary for fuel security over three Capacity Commitment Periods, beginning in 2022-23 and ending in 2024-25.[86] ISO-NE must perform a fuel security reliability review for resources that submit Retirement De-List Bids in the relevant Forward Capacity Auctions to determine whether a resource should be retained for fuel security.[87] ISO-NE uses an updated version of the OFSA model for this review.[88] As ISO-NE explained, "[t]he fuel security reliability review is a *90-day winter* energy analysis" that was designed solely to identify risks in the winter months from December to February.[89] Indeed, ISO-NE left no room to quibble that the scope of its compliance obligation was limited to the winter period: "The Tariff revisions submitted in this filing have the same goal as the Tariff revisions submitted for the 2005-2006 winter and the 2014-2015 winter, *i.e.*, to improve reliability by ensuring that adequate electric energy supply is available to meet real-time load during the winter."[90]

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86 *See* December 2018 Order at PP 1, 5.

87 *Id.* at PP 10-11.

88 *Id.* at P 11.

89 ISO New England Inc., Compliance Filing to Establish a Fuel Security Reliability Standard, Short-Term Cost-of-Service Mechanism, and Related Cost Allocation for Out-of-Market Compensation, Docket Nos. EL18-182-000 and ER18-2364-000 (filed Aug. 31, 2018), at 7 (emphasis added).

90 *Id.* at 15. *See* December 2018 Order at P 41.

Earlier this year, ISO-NE reiterated in a report sent to stakeholders and the Commission that the scope of its long-term fuel security compliance obligation is limited to the winter period: "Designing and implementing long-term *winter* energy-security improvements is a large, complex, multiyear project to develop the rules, complete quantitative and qualitative analyses on the design, and review the details with stakeholders."[91] The ESI Proposal abruptly changes the direction of ISO-NE's compliance obligation by implementing a program that applies year-round.

Moreover, the ISO-NE Filing does not explain why applying ESI in the non-winter months is necessary to solving the root energy security problem it identified in its filing, misaligned incentives. ISO-NE explains the nexus between natural gas pipeline constraints and the misaligned incentives problem:

> If a generator does not make . . . a costly additional fuel supply arrangement, then when the region's gas pipelines are tightly constrained and renewables' output is low, high real-time wholesale energy market prices will prevail. These high prices cost consumers dearly, but do not immediately benefit the generator if it lacks fuel to operate (because it did not make the necessary fuel supply arrangements). Those high market price signals normally motivate widespread investment to profit in such circumstances. And yet, if the generator does invest in more robust fuel supply arrangements – at least, to a level that meaningfully reduces the system's energy supply risk – then the investment may obviate the market's high energy price, undermining the generator's expected return on the investment. Given these misaligned incentives, and that nearly any investment in additional energy supply arrangements tends to entail significant costs upfront, it is no surprise that few generation owners perceive adequate incentives to undertake them.[[92]]

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91 ISO New England, 2020 Regional Electricity Outlook, Feb. 2020, at 33, available at https://www.iso-ne.com/static-assets/documents/2020/02/2020_reo.pdf. On March 19, 2020, ISO-NE filed a link to the report in multiple Commission dockets, including one of the dockets in this proceeding: EL18-182-000, ER13-2266-004, ER18-1509-000, ER18-1509-001, ER18-2364-000, ER19-1428-000, and ER18-1639-000 through ER18-1639-003.

92 ESI White Paper at 3.

Nothing in the ISO-NE Filing demonstrates that pipeline constraints or an inability to procure fuel are problems outside of the winter months.

To the contrary, the ISO-NE Filing confirms its representation of fuel security as a winter problem. The Impact Assessment explains how natural gas available to electric generators decreases when temperatures drop and, in discussing ESI's impact outside the winter period, states that "fuel supply during the non-winter months does not face the constraints experienced in the winter months."[93] The ESI White Paper makes a similar point.[94] ISO-NE's presentation at the 2019 FERC Meeting also replayed what has long been known in the region: "Gas pipelines reaching New England from the West are **fully utilized** in cold weather[.]"[95] ISO-NE further stated that "[g]as-only or dual-fuel" units "are likely to become predominant resources for replacement energy and load-balancing reserves" and that they will "face production uncertainty during winter[.]"[96] ISO-NE's presentation contained no description of fuel security risks occurring in the non-winter period.

The NEPOOL Filing lends additional support in aligning the Commission's directives with winter fuel security concerns. In his testimony, Mr. Daly, Eversource's Vice President of Energy Supply, explains that "concerns about fuel security are limited to the most severe peak winter days."[97] He discusses how the winter period correlates with the highest demand for gas across the system and states that the lack of "pipeline constraints outside the winter months"

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93 Impact Assessment at 36, 78.

94 ESI White Paper at 1 (concluding that "cold weather conditions" cause interstate natural gas pipelines to "rapidly reach capacity and [become] unable to fuel many of the region's power plants.") (footnote omitted).

95 ISO New England, Energy Security Improvements: Market Solutions for New England, Federal Energy Regulatory Commission Staff-Led Public Meeting, Docket Nos. EL18-182-000 et al., July 15, 2019, at Slide 10 (emphasis in original), available at https://www.iso-ne.com/static-assets/documents/2019/07/07_12_2019_ferc_white_final_web.pdf.

96 *Id.* at Slide 25.

97 Daly Testimony at 6.

should present "little difficulty sourcing the energy needed to address the RER reliability concern."[98] Mr. Griffiths further discusses how the Impact Assessment illustrates that any projected reserve deficiencies would occur only in the winter period.[99] He similarly concludes that, "from the standpoint of market efficiency, the [Impact Assessment] results imply that the entire ESI design could be eliminated in the non-winter months with no ill-effect on production costs."[100]

Furthermore, to the extent ISO-NE now appears to point to renewable resources as presenting another fuel security risk and one that is year-round, it includes no meaningful evidence to support that claim.[101] Unlike the OFSA and Mystic Retirement Studies on which the Commission relied in issuing the July 2018 Order, ISO-NE provides no analysis establishing a correlation between renewable power and current or emerging threats to meeting reliability standards. In fact, ISO-NE analysis indicates that wind energy could provide significant system reliability benefits during *stressed winter conditions*, the ESI program's primary target.[102]

ISO-NE is also getting ahead of ongoing regional work to consider reliability needs as more renewable and clean energy resources become operational. In collaboration with NESCOE and NEPOOL, ISO-NE is in the beginning stages of stakeholder discussions that would include an assessment of future system conditions and operational needs taking into account state energy

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98 *Id.* at 4-6.

99 *See* Griffiths Testimony at 13-15.

100 *Id.* at 19.

101 *See* Transmittal Letter at 9, 26-27; Brandien Testimony at 4, 24-25; ESI White Paper at 11.

102 *See* ISO New England, Memo to New England Stakeholders, High-Level Assessment of Potential Impacts of Offshore Wind Additions to the New England Power System During the 2017-2018 Cold Spell, Dec. 17, 2018, at 2-3, available at https://www.iso-ne.com/static-assets/documents/2018/12/2018_iso-ne_offshore_wind_assessment_mass_cec_production_estimates_12_17_2018_public.pdf.

and environmental requirements.[103] ISO-NE's proposal to use the ESI program to manage reliability needs in connection with clean energy resources sidesteps this collaborative process. ISO-NE, working with states and stakeholders, can propose market rules to meet the future needs of the system after this deliberative regional process has concluded.

Similarly, ISO-NE's description of a single scarcity event on September 3, 2018—the only scarcity event ISO-NE points to in the hundreds of pages of its filing and the only one since implementation of PFP—does not justify the expansion of its full ESI program to all months of the year. There is no claim that suppliers were unwilling to arrange for the fuel needed to run on that fall day (i.e., the misaligned incentives problem) or that fuel constraints contributed to this event. ISO-NE confirms that resources came on-line "throughout the day in an attempt to replace the lost energy."[104] While the need to dispatch resources out-of-market could support an evaluation of improved price signals for reserves, nothing in the record establishes that this was a fuel security event.

ISO-NE's proposal to apply the ESI program in all months is inconsistent with its long history of characterizing fuel security risks as a winter problem. ISO-NE's unilateral attempt to change the scope of the Commission's directives, if not rejected, would come at a great cost to consumers and without required notice in the July 2018 Order that the Commission's directives implicated the non-winter period.[105]

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[103] *See, e.g.,* ISO New England, Transition to the Future Grid Key Project, available at https://www.iso-ne.com/committees/key-projects/transition-to-the-future-grid-key-project/; ISO New England, New England's Wholesale Electricity Markets: The Clean Energy Transition and Future Pathways, Mar. 10, 2020, at Slide 31, available at https://www.iso-ne.com/static-assets/documents/2020/02/iso_ne_clean_energy_transition_2020.pdf.

[104] Brandien Testimony at 23.

[105] *See* 5 U.S.C. § 554(b)(3) (requiring that parties be "timely informed of . . . the matters of fact and law asserted."); *Pub. Serv. Comm'n v. FERC*, 397 F.3d 1004, 1012-13 (D.C. Cir. 2005) (finding that the Commission acted unlawfully in failing to provide parties with adequate notice of the issues to be decided); *accord Dominion* at 587, 593 (vacating compliance order because, *inter alia*, it "was far broader than the order on which it purportedly rested").

b. The ESI Proposal Does Not Squarely Address the Commission's Fuel Security Concerns

In addition to expanding the scope of the July 2018 Order beyond the winter period, the ESI Proposal does not sufficiently address fuel security concerns. First, ISO-NE has not demonstrated that its proposed design will result in the fuel security investments it claims to achieve through ESI. The Wilson Testimony describes how the ESI Proposal "likely will not adequately address the New England energy security problem."[106] Mr. Wilson evaluates ESI's core design and concludes that, even assuming it could be made efficient, the design fails to provide anything more than a "modest" impact on a supplier's incentive to make advance fuel arrangements.[107] The misaligned incentives problem, Mr. Wilson explains, occurs only in narrow circumstances and, even in those rare occasions, the energy call option may not lead resources to change their practices.[108]

Mr. Wilson further identifies various inefficiencies inherent in the ESI design.[109] He testifies that, while those inefficiencies could result in suppliers receiving more substantial revenues to encourage investments, "strengthening energy security mainly through introducing inefficiencies into the [day-ahead] market is not sound market design and does not provide value to consumers."[110] In any event, Mr. Wilson testifies that he does not believe that such incentives in the day-ahead market would be effective in influencing resources to take seasonal- or years-

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[106] Wilson Testimony at 23.

[107] *See id.* at 11, 13-17, Section IV.

[108] *Id.* at Section IV; *see id.* at 14-15.

[109] *See id.* at 33-37. These inefficiencies are discussed below.

[110] *Id.* at 15; *see id.* at 16-17, 33-37.

forward actions promoting greater fuel security, given uncertainty and variation in incentive levels and a likely reduction in inefficiencies and associated revenues over time.[111]

Second, the ESI program represents a novel and untested approach to improving price formation. ESI's focus is providing a more reliable day-ahead operating plan to increase the likelihood that resources are available to respond to contingency events.[112] Contingency events, however, do not necessarily have a direct correlation to fuel security. ISO-NE points to no instances in its filing of a contingency event caused by the failure of suppliers to make advance fuel arrangements.[113] This mismatch between ISO-NE's design and the Commission's compliance directive was recognized early in the development of the ESI program. As the representative of one of New England's power generators succinctly testified at the 2019 FERC Meeting, ISO-NE's proposed reserve products "are simply operational enhancements that do nothing to address the long-term fuel security issue."[114]

The Commission should not take a chance on the ESI experiment. Enhancing price formation is a laudatory objective, and aligning pricing for ancillary services with dispatch needs could be one piece of the puzzle in solving for fuel security. However, this proceeding is not the appropriate forum to consider price formation reforms that do not squarely meet the Commission's directives to ISO-NE. Indeed, because the ESI Proposal does not adequately

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111 *Id.* at 15-16.

112 *See* Transmittal Letter at 14.

113 In fact, ISO-NE notes that insufficient energy supplies have not been the cause of a loss of load to date. *Id.* at 11.

114 Statement of Brett Kruse, Vice President of Market Design, Calpine Corporation, July 15, 2019 Staff-Led Public Meeting, at 3, available at https://www.ferc.gov/CalendarFiles/20190717100350-Kruse,%20Calpine.pdf. Mr. Kruse expressed his company's general support for the proposed enhancements "to co-optimize reserves in the day-ahead market as an improvement to energy market price formation, with one caveat – these enhancements must ensure that the reserve commitments in the day-ahead market become physical commitments to provide the service in real-time." *Id.*

address fuel security concerns, NESCOE expects that ISO-NE will return with yet another remedy at a later juncture, seeking to impose even more costs on consumers.

ISO-NE has a ready mechanism to pursue price formation changes if it should desire to do so. As it has done many times before, ISO-NE can propose such changes through the stakeholder process and file them with the Commission under section 205 of the FPA. For example, several years ago ISO-NE filed, and the Commission accepted, Tariff revisions to provide resources with flexibility to change offers in real-time and vary offers by hour to better align financial incentives and dispatch instructions.[115] NESCOE supported these changes, citing to their potential to improve market efficiency and system reliability.[116]

In 2015, ISO-NE filed, and the Commission accepted, changes "to improve real-time price formation when fast-start resources are deployed."[117] Less than one year later, the Commission accepted an ISO-NE proposal "to change the settlement interval in the real-time energy and reserves markets from hourly intervals to five-minute intervals."[118] ISO-NE developed those changes to "enhance Market Participant incentives to follow dispatch instructions and more accurately compensate participants for the energy and reserve products they deliver in Real-Time."[119] NESCOE also supported ISO-NE's proposals to implement and refine system-wide and zonal sloped demand curves.[120] Though the immediate implementation

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[115] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 at PP 1, 5-6, 33 (2013) ("Offer Flexibility Order"), *order on compliance*, 147 FERC ¶ 61,073 (2014).

[116] Offer Flexibility Order at P 22.

[117] *ISO New England Inc. and New England Power Pool Participants Comm.*, Delegated Letter Order, Docket No. ER15-2716-000 (Oct. 19, 2015) ("Fast Start Order").

[118] *ISO New England Inc. and New England Power Pool Participants Comm.*, Delegated Letter Order, Docket No. ER16-1838-000 (July 26, 2016).

[119] Joint Filing of ISO New England Inc. and New England Power Pool to Implement Sub-Hourly Settlements, Docket No. ER16-1838-000 (filed June 2, 2016), at 7.

[120] *ISO New England Inc. and New England Power Pool Participants Comm.*, 155 FERC ¶ 61,319 at P 34 (2016).

of the zonal curves could have provided short-term consumer savings, in the interest of long-term market efficiency, NESCOE worked with stakeholders to develop an amendment that ISO-NE incorporated into its proposal to phase-in the changes over time.[121]

This list is not exhaustive. ISO-NE has dedicated a key project to identifying the need for energy market pricing reforms and developing solutions to those needs.[122] NESCOE looks forward to continuing to work with ISO-NE and stakeholders on identifying the need for further market rule changes to enhance price formation and in designing solutions that meaningfully consider the benefits and costs of the proposed approach. But that should take place in a different proceeding following a stakeholder process, not in a section 206 proceeding in which ISO-NE is required to comply with a narrower Commission directive.

2. The Replacement Rate Is Not Just and Reasonable

The Commission initiated this section 206 investigation into ISO-NE's Tariff, having preliminarily found that the Tariff may be unjust and unreasonable because it does not adequately "address specific regional fuel security concerns."[123] Section 206 of the FPA directs "a two-step procedure that requires FERC to make an explicit finding that the existing rate is unlawful before setting a new rate."[124] Pursuant to "section 206, it is the Commission's job . . . to find a just and reasonable rate" and its "burden to prove the reasonableness of its change in methodology."[125] While courts grant the Commission deference in setting a new rate, "in all cases, the Commission must explain its reasoning when it purports to approve rates as just and

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121 *See* Comments of the New England States Committee on Electricity, Docket No. ER16-1434-000, at 3 (filed May 13, 2016).

122 *See* https://www.iso-ne.com/committees/key-projects/implemented/energy-market-pricing-enhancements.

123 July 2018 Order at P 49; *see also id*. at PP 2, 55.

124 *Emera* at 24.

125 *Advanced Energy* at 663.

reasonable."[126] Among other things, when evaluating ISO-NE's proposal, the Commission must bear in mind that "rates that permit excessive profits are not just and reasonable."[127]

When a Commission order issued under section 206 "consists precisely of a determination that what it prescribes will produce just and reasonable rates, the only issue remaining is whether the compliance filing accords with what it prescribes."[128] However, when "the prescription is . . . indeterminate . . . no determination of justness and reasonableness can realistically be said to have been made and acquiesced in at the stage of the original order."[129] In such a case, "[t]he Commission may have deferred its final judgment on justness and reasonableness until the compliance filing[.]"[130]

The July 2018 Order directed ISO-NE to file Tariff revisions to implement a long-term, market-based solution to address specific fuel security concerns but was otherwise indeterminate in prescribing the design and changes ISO-NE is required to make. The Commission thus deferred to this compliance proceeding whether the replacement rate is just and reasonable.[131] For the reasons discussed below, ISO-NE's proposed replacement rate is not just and reasonable and NESCOE respectfully urges the Commission to reject it.

a. Without Effective Rules for Mitigation, the ESI Proposal Is Incomplete, and the Rates in the Proposal Cannot Be Found to be Just and Reasonable

Just a few months ago, the Commission rejected ISO-NE's filing to sunset the mechanism in its Forward Capacity Market rules that allows it to retain a resource for fuel

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126 *Emera* at 23 (cleaned up).

127 *TransCanada* at 12.

128 *City of Cleveland v. FERC*, 773 F.2d 1368, 1374 (D.C. Cir. 1985).

129 *Id.*

130 *Id.*

131 Additionally, as noted above, the July 2018 Order made a preliminary finding that the Tariff may be unjust and unreasonable and the Commission has yet to find that the existing rate is unjust and unreasonable.

security reasons.[132] The Commission rejected the filing without prejudice, finding it unjust and unreasonable because it would prematurely terminate the fuel security mechanism while the "Permanent Market Solution" was not yet before it.[133] Without rules for adequately mitigating market power, the compliance filing that ISO-NE has submitted does not provide the Commission with a complete "Permanent Market Solution." Absent a plan for mitigating market power, the ESI Proposal cannot be deemed just and reasonable, does not represent a complete proposal, and is non-compliant with the July 2018 Order.

The effective mitigation of market power is, of course, a threshold requirement for charging market-based rates.[134] "Where sellers do not have market power or the ability to manipulate the market (alone or in conjunction with others), it is not unreasonable for FERC to presume that rates will be just and reasonable."[135] Critically, "*before* FERC approves an individual seller's use of market-based pricing . . . it must determine that 'the seller and its affiliates do not have, or adequately have mitigated, market power in'" supplying generation.[136]

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132 February 2020 Order at P 1.

133 *Id*. at P 17.

134 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 at P 5 (2019) ("The Commission allows power sales at market-based rates if the Seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.") (citing *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 at PP 62, 399, 408, 440, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, *sub nom. Public Citizen, Inc. v. FERC*, 567 U.S. 934 (2012)).

135 *Mont. Consumer Counsel*, 659 F.3d at 919.

136 *Blumenthal v. FERC*, 552 F3d 875, 882 (D.C. Cir. 2009) (quoting *La. Energy & Power Auth. v. FERC*, 141 F.3d 364, 365 (D.C. Cir. 1998)) (emphasis added); *see Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311 at PP 37-43 (2007) ("2007 Order") (rejecting without prejudice request to evaluate ancillary services market design due to absence of accompanying market power analysis), *reh'g denied* 120 FERC ¶ 61,202 (2007).

A Commission order on the ESI Proposal will need to explain how market power is addressed; simply pointing to the existence of competition is insufficient.[137]

ISO-NE acknowledges the need for a market power assessment in support of ESI but states that it needs additional time to complete the analysis and to develop any mitigation rules.[138] As filed, the ESI Proposal is thus incomplete. ISO-NE does not explain how it will screen suppliers for market power and there is no way, based on the record, for the Commission to determine that suppliers "do not have, or adequately have mitigated, market power" in selling ESI products.

Without a market power assessment and mitigation proposal, the Commission cannot evaluate whether the ESI Proposal is just and reasonable. As in the 2007 Order, the ISO-NE Filing "is deficient without a market power analysis as part of its overall proposal."[139] In that order, the Commission recognized the Midwest ISO's preference for FERC to approve the "framework" of a new ancillary services market for operating reserves while work on a market power assessment continued.[140] However, the Commission found that it could not fully evaluate the merits of the proposed market design without that market power assessment.[141] The same reasoning applies here. ISO-NE's completion of a market power assessment is a condition precedent to the Commission's evaluation of the ESI Proposal.

In failing to address market power concerns, the ISO-NE Filing is in effect a request to the Commission for a declaratory order that the ESI Proposal "framework" is just and reasonable

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137 *See TransCanada* at 13 (citing *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004-05 (D.C. Cir. 1990)).

138 Transmittal Letter at 70-71.

139 2007 Order at P 37.

140 *Id.*

141 *Id.* at PP 37-43.

and that it meets ISO-NE's obligation to comply with the July 2018 Order. The Commission should decline that invitation. Until ISO-NE answers the "threshold question" regarding market power, any request to approve ESI is premature and ISO-NE's filing is deficient.[142]

Indeed, the ESI Proposal is especially vulnerable to the exercise of market power. The Wilson Testimony details the unique ESI features that make the design more susceptible to market power than more conventional approaches to day-ahead ancillary services, especially under certain system conditions.[143] NESCOE and others, including the Internal Market Monitor ("IMM") and the EMM, identified market power concerns associated with ESI early in the stakeholder process.[144] Given the core design of the ESI Proposal, Mr. Wilson describes the significant challenges in developing rules to address the exercise of market power.[145] He concludes that an effective approach to mitigation is doubtful and expects "that the mitigation ultimately will be very loose and ineffective, contributing to the inefficiency and excessive cost" that he expects ESI will impose on consumers.[146]

The Commission's recent decision in connection with ISO-NE's first winter reliability program from 2013-2014 ("Winter Program I") illustrates the need for clear rules regarding how ISO-NE intends to restrain the exercise of market power under ESI *before* the Commission can accept the program as just and reasonable.[147] In Winter Program I, ISO-NE implemented a "pay-

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142 *Id.* at PP 37, 42; *see Californians for Renewable Energy, Inc.*, 119 FERC ¶ 61,311 at P 27 (2007) (reviewing court will assess whether the Commission has made "an *ex ante* finding of the absence of market power" in connection with a proposed market-based rate program) (citing *Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004)).

143 Wilson Testimony at Section V.A.

144 *Id.* at 39-41; *see id.* at 45 (citing to IMM and EMM materials suggesting that market power would exist and identifying a need for mitigation).

145 *Id.* at 45-54.

146 *Id.* at 54; *see id*. at 12, 53. Mr. Wilson testifies that the NEPOOL Proposal can help limit the potential for these excessive costs and inefficiencies. *Id.* at 54.

147 ISO New England Inc., 171 FERC ¶ 61,003 (2020) ("Winter Program I Order"), *reh'g pending*.

as-bid" auction to procure resources providing demand response or oil inventory.[148] The Commission accepted the program as a temporary solution to New England's winter reliability issues, which ISO-NE identified as "reliability risks" relating to "the region's increased reliance on natural gas-fired resources and resource performance during stressed system conditions."[149] Following subsequent Commission orders on Winter Program I, the D.C. Circuit granted in *TransCanada* a petition challenging the auction results. The Court found that the record lacked any evidence regarding the extent to which the program's cost reflected profit and risk mark-up and that the Commission never addressed that issue.[150] The Court also found, *inter alia*, that the Commission did not explain why it believed the program to be competitive.[151] The Court rejected arguments that the program was just and reasonable because ISO-NE conducted a competitive pay-as-bid auction.[152] Having found that the Commission did not attempt "to explain the economic forces that it believed restrained the suppliers in their confidential bid offers" and "made no effort to define the relevant market or determine the participants' market power,"[153] the Court remanded the case to FERC.

On remand, the Commission required ISO-NE and the IMM to provide information and analysis regarding the competitiveness of the program and whether bidding behavior suggested that participants exercised market power.[154] The Commission relied on this new information in finding, more than six years after the Winter Program I auction, that the auction results were just

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[148] *Id.* at P 4.

[149] *Id.* at PP 3, 9.

[150] *TransCanada* at 12.

[151] *Id.* at 13.

[152] *Id.*

[153] *Id.*

[154] Winter Program I Order at P 21.

and reasonable, including its determination that ISO-NE "sufficiently restrained" the ability of participants to exercise market power.[155]

Like ISO-NE's initial filing in Winter Program I, the ISO-NE Filing is devoid of the record the Commission requires to find that the ESI Proposal will be competitive and that market power will be addressed. ISO-NE does not support its filing with a market power assessment and provides no information on how it intends to restrain the exercise of market power, which is especially problematic during stressed system conditions. Without record evidence that market power is sufficiently addressed, uncertainty will hang over the legality of the ESI Proposal in the same way that it did (and still does) regarding ISO-NE's earlier winter program.

The Commission should not approve an ESI program that lacks effective rules to guard against uncompetitive outcomes. The novelty of ISO-NE's call option on energy design, which may be without precedent in any RTO as Mr. Wilson explains,[156] heightens the importance of understanding the market power risks inherent in the ESI Proposal and whether those risks can be effectively addressed.

The ISO-NE Filing does not provide a basis for the Commission to find that the novel call option design would produce a truly competitive market-based rate. At minimum, the Commission should reject the ISO-NE Filing, without prejudice, as premature and incomplete without rules to address market power.

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[155] *Id.* at PP 54, 61, 70.

[156] Wilson Testimony at 55.

b. The ESI Proposal Overcharges Consumers

i. ISO-NE's Preference to Use ESI as an Alternative Approach to Meeting Mandatory Reliability Standards Cannot Override the Requirement that Rates Be Just and Reasonable

As a starting point, ESI's excessive costs cannot be excused simply because ISO-NE has elected to rely on newly created ancillary services as an alternative approach to satisfying reliability standards. The ISO-NE Filing describes in detail various reliability standards related to energy supply planning and reserve requirements.[157] None of these standards mandate a singular path for compliance.[158] ISO-NE acknowledges that fact,[159] and NESCOE understands that ISO-NE is currently compliant with those reliability standards under its current approach.[160] ISO-NE's discretion in how to meet reliability standards is not an open-ended license to charge consumers. The flexibility that NERC and NPCC provide in meeting their standards cannot, and must not, override the FPA's mandate that the Commission protect consumers from excessive costs.

ISO-NE is an outlier in proposing to satisfy reliability requirements through ESI. No other RTO appears to employ this kind of day-ahead call option on real-time energy.[161] The proposed RER product best illustrates ISO-NE's singular approach.[162] NERC and NPCC

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157 *See, e.g.,* Brandien Testimony at 6-17.

158 *See generally* Bergeron Testimony.

159 *See* Transmittal Letter at 16-17 (describing ISO-NE's current approach to satisfying reliability standards); Brandien Testimony at 17-22 (same) and 27 (noting that ISO-NE develops and executes a daily operating plan to comply with NERC and NPCC requirements); *see also* ESI White Paper at 10 (describing ESI program as "tightly coupled to existing reliability standards").

160 *See* Wilson Testimony at 71-72; Bergeron Testimony at 2 (recounting that ISO-NE confirmed during the stakeholder process that "it is already in compliance with all of these standards and procedures under its existing construct, without ESI.").

161 Wilson Testimony at 13, 55; *see* Transmittal Letter at 43.

162 *See, e.g.,* ISO New England, Energy Security Improvements: Market-Based Approaches, Day-Ahead Reserves - Alternative Settlement Design and its Fuel Security Implications, NEPOOL Markets Committee, Dec. 10-11, 2019 ("December 2019 Presentation"), at Slide 30 (describing how NYISO and MISO procure day-ahead reserves), available at https://www.iso-ne.com/static-

standards require Balancing Authorities to have a specific amount of ten-minute and thirty-minute operating reserves and provide timelines for restoration if there are deficiencies.[163] But, as Mr. Bergeron, a member of the NPCC Board of Directors, testifies, nothing in any of the NERC or NPCC standards requires a Balancing Authority to procure reserves to replace reserves, as RER would do.[164] He adds that he has "not seen any other [RTO] suggest that either NERC or NPCC criteria require obtaining reserves day-ahead to replace reserves in the unlikely possibility of an operating day contingency event or other reserve depletion."[165] Moreover, no other region appears to procure a reserve product to address a *third* contingency, as ISO-NE is proposing to do.[166]

Mr. Wilson testifies that the NPCC standard "does not impose any requirement equivalent to RER" and, even if there was a need for an RER-type product in real-time, there is no standard requiring that it be acquired day-ahead.[167] Mr. Griffiths also explains why "[a]n RER style product is not required to comply with NPCC's reserve requirements," concluding that it is "permissible, but certainly not obligatory" under the standards.[168] Indeed, he testifies that, "given the general lack of reserve deficiencies under ESI or current market rules, as

assets/documents/2019/12/a6_c_iii_presentation_da_reserves_alternative_settlement_design_fs_implications.pptx.

163 *See* Bergeron Testimony at 2-6.

164 *Id.* at 4, 6 (explaining that no standard requires Balancing Authorities "to plan for stacking an additional layer of reserves to replace reserves in the Operating Plan."); *see* Wilson Testimony at 72 ("[W]hile Directory 5 identifies minimum quantities for contingency reserves, it does not impose any requirement equivalent to RER.").

165 Bergeron Testimony at 6.

166 *See* Brandien Testimony at 30 (describing procurement of reserves to respond to 50% of a third contingency loss; ESI White Paper at 159 (Table 7-2); ISO New England, Day-Ahead Enhancements, Technical Session 2, April 2, 2019 ("Technical Session 2"), at Slide 49, available at https://iso-ne.com/static-assets/documents/2019/04/20190402-da-enhancements-tech-session-2.pdf.

167 Wilson Testimony at 72.

168 Griffiths Testimony at 10-11.

modeled [in the Impact Assessment], we can infer from these results that the system can meet its reliability obligations with or without ESI as a whole."[169]

NESCOE understands that the New York Independent System Operator ("NYISO"), which is also subject to both NERC and NPCC requirements, meets these reliability standards without having implemented an ESI-type design. It does not offer an RER-type product to procure reserves to replace reserves or procure reserves to address a third contingency event, as far as NESCOE is aware.[170]

ISO-NE's election to meet NERC and NPCC requirements through ESI cannot supersede the FPA's prohibition against overcharging consumers. ISO-NE's choice of ESI as an alternative approach to meeting reliability standards is just that: a choice. To be sure, a first-class ticket can be enticing, but that doesn't make it a reasonable investment in getting to the same destination. ISO-NE cannot justify the ESI Proposal's substantial costs on the basis of NERC and NPCC compliance obligations.

ii. The ESI Program Overvalues and Overbuys Call Options

There is a fundamental mismatch between the price ISO-NE would charge consumers for ESI and the reliability benefits it would provide. There are two ways in which this mismatch emerges. First, in determining the quantity of ancillary services to purchase under ESI, ISO-NE overvalues its products by failing to reflect a diminished marginal reliability value ("MRV"). Second, ISO-NE has not demonstrated that system needs require it to exercise the full freight of call options purchased under ESI. The Impact Assessment further places ESI's excess in stark

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[169] *Id.* at 13. Mr. Griffiths discussed both historic and projected system reserve deficiencies. *See id.* at 13-18.

[170] *See* December 2019 Presentation at Slide 30; Technical Session 2 at Slide 49.

view, showing a grossly disproportionate incentive rate compared to suppliers' additional holding costs for fuel oil.

For each ESI product, ISO-NE sets one price for the full quantity it seeks to acquire. ISO-NE proposes to use the price caps it applies to reserves purchased in real-time—*i.e.*, Reserve Constraint Penalty Factors ("RCPFs")—in setting the clearing prices for ESI.[171] The consequence of this design choice, Mr. Wilson testifies, is to subject consumers to "maximum prices based on RCPFs that greatly exceed the" MRV of quantities purchased.[172] Mr. Wilson describes the shortcomings of ISO-NE's intended approach:

> Shortage prices are supposed to reflect the marginal reliability value of incremental [real-time] reserves at different levels of shortage; this well-established principle is discussed further later in this section of my testimony. In a forward context – be it years, months, weeks, or even just a day forward – the same bid-in supply and demand balance reflects very different risk and marginal reliability value as in [real-time]. Should the bid-in supply and demand in a forward market appear to signal scarcity, there is time for loads, suppliers and [ISO-NE] to take additional actions before the delivery period to improve the supply-demand balance – time, and actions, that are not available in the [real-time] market context for which shortage price rules were developed. Thus, a bid-in supply-demand situation in a forward context represents lower true risk of an actual delivery period shortage than the same bid-in supply-demand balance in the [Real-Time] market.
>
> In addition, the appropriate value of lost load ("VOLL") for use in evaluating MRV [day-ahead] is somewhat lower than the value applicable to [real-time], due to the forward price signal and additional time. When a forward market signals some degree of scarcity, this gives [ISO-NE] and utilities time to warn consumers and suppliers of a possible tight situation that could lead to firm load drop, and this gives consumers and suppliers time to prepare. Advance warning lowers the impact on consumers of curtailment (VOLL), and such advance warning is not necessarily available when shortages occur in the [real-time] market.[[173]]

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171 ISO-NE Filing at 50.

172 Wilson Testimony at 12; *see id.* at Section V.D.

173 *Id.* at 61-62.

Mr. Wilson explains how ISO-NE could reflect MRV in setting the maximum prices for different quantities of reserves under ESI.[174] He also notes that the Forward Capacity Market demand curve currently applies the MRV concept.[175] In fact, as discussed below, ISO-NE's procurement decisions in its first winter reliability program were guided by the MRV of the quantities purchased.[176] ISO-NE does not explain why it has taken a different approach in this fuel security program, nor does it provide the Commission with analysis justifying the high prices it proposes to pay the full quantity of reserve products under ESI.[177]

ESI also overbuys reserves. As the EMM explained:

> . . . use of the option style contract would require loads to take day-ahead positions in energy that *substantially exceed* their expected real-time energy needs, since loads would be required to purchase "at the money" call options for an amount of operating reserves that is *extremely likely to exceed* the amount that would be converted to energy in real-time. Ultimately, it is difficult to predict the extent to which the option style contract will allow [ISO-NE] to maintain reliability more efficiently than it would using the conventional forward contract for ancillary services.[[178]]

In short, ISO-NE is making consumers buy more reserves in a day-ahead market than the system would typically need in real-time.

As it has demonstrated through past support of certain ISO-NE price formation-improving proposals, discussed above, NESCOE is not opposed to resources being fairly

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174 *Id.* at 64-69.

175 *Id.* at 60.

176 Winter Program I Order at P 34 (ISO-NE "evaluated the marginal cost of each incremental quantity and determined that the reliability benefits from the [p]rogram met or exceeded [p]rogram costs at the chosen procurement level" and while it could have purchased greater quantities ISO-NE "judged that the incremental reliability benefits from additional procurement were not worth the additional costs.") and P 63 ("[I]n selecting a procurement level, it is evident that ISO-NE considered the tradeoff between reliability and customer costs.").

177 Wilson Testimony at 60, 63.

178 EMM Memo at 2 (emphasis added) (footnote omitted).

compensated for the services they provide. NESCOE also supports the concept of procuring ancillary services in the day-ahead market, which in principle "should improve efficiency and energy security, and lower costs to consumers."[179] However, ISO-NE's intent to design a program that ensures "compensation cannot simply be a handout"[180] is thwarted by what is, in effect, an incentive rate that would provide resources with incremental revenues from ESI that "far exceed" the additional costs they would incur to hold fuel.[181]

Mr. Griffiths also raises concern regarding ESI's high incentives. He questions whether the calculation of incentives considered the appropriate amount to promote fuel security, asking rhetorically, "Would creating incentives to procure fuel worth a billion dollars per MWh actually change behavior any more than a billion dollars less one?"[182] After comparing ESI's incremental costs to the estimated value of lost load, Mr. Griffiths concludes that the "ESI proposal favored by [ISO-NE] offers poor value for money[.]"[183]

ISO-NE's analysis of ESI's quantitative and qualitative impacts puts this excess into clear view. The Impact Assessment, among other things, compared the additional revenues that suppliers would receive under ESI to the additional costs of holding fuel oil.[184] The results show "that the average incremental payments to resources under ESI generally *far outweigh* the

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179 Wilson Testimony at 8.

180 ESI White Paper at 81.

181 Impact Assessment at 52.

182 Griffiths Testimony at 21 (emphasis removed).

183 *Id.* at 28.

184 Impact Assessment at 52-53.

additional holding costs."[185] In some cases, the revenues for the analyzed resource types exceeded added holding costs by a staggering amount.[186]

The Impact Assessment examined market conditions over a range of potential winter conditions: (1) a severe or "Frequent Case" reflecting "multiple, shorter periods with fuel system constraints, driven in large part by numerous cold-snaps," based on the winter of 2013-14 (the so-called "polar vortex") (2) a moderate or "Extended Case" representing "one extended period with fuel system constraints, which occurred during a long cold-snap in late December and early January" of 2017-18, and (3) a mild or "Infrequent Case" consisting of a winter period having "particularly mild temperatures and no periods of stressed conditions."[187]

In the Frequent and Extended Cases, "ESI revenues far exceed the change in holding costs for all fuel-oil resource categories evaluated."[188] As discussed above, dual fuel, combined cycle generation examined under the Frequent Case is projected to incur $14 per MW in holding costs while earning increased revenues of $5,591 per MW under ESI, for a net revenue increase of $5,577 per MW.[189] In other words, ESI would provide those suppliers with an incentive that is 398 times greater than the fuel holding costs—a misaligned incentive indeed.

Even in a mild winter, as seen in the Infrequent Case, most dual fueled and oil-fired resources would still see double- and triple-digit returns on holding costs, with only one resource type studied, oil-only steam resources, dipping into negative returns at the level of assumed fuel

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[185] *Id.* at 52 (emphasis added); *see* Transmittal Letter at 30.

[186] These returns would be even greater when load forecast error is included, as reflected is in the "RER Plus" scenario. *See* Section III.B.2 below.

[187] Impact Assessment at 14.

[188] *Id.* at 52.

[189] *Id.*; *see* Transmittal Letter at 30.

inventory.[190] However, the Impact Assessment is quick to note that oil-only steam units "still incur positive gains that are larger in magnitude in the winters with more frequent stressed conditions (i.e., the Frequent and Extended Cases)."[191] In summary, the analysis concludes that "[t]hese results demonstrate that the additional revenues in the market from ESI far exceed the change in costs of holding additional fuel, and provide one illustration of the incentives ESI creates for oil resources to increase the quantity of fuel held during the winter."[192]

The Impact Assessment shows that ESI may be a stronger medicine than the system needs to cure any fuel security ailments, and one with significant negative side effects on consumers' wallets. The analysis shows that resources would be rewarded with net earnings that may be dozens to hundreds of times more than their costs to hold fuel, leading to the undeniable conclusion that ESI's financial incentives are excessive.[193] Despite ISO-NE's efforts to design a program that, in theory, avoids giving handouts to those supplying energy, the record ISO-NE provides in this proceeding contradicts any claim that consumer interests have been meaningfully considered. The excessive incentive levels reflected in the Impact Assessment's results should alone preclude the Commission from finding that the replacement rate is just and reasonable.[194]

NESCOE agrees with NEPOOL that "reliability benefits are no excuse for excess costs."[195] If the Commission accepts the ISO-NE Filing, it is required to provide a reasoned

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[190] *See* Impact Assessment at 52-53.

[191] *Id.* at 52.

[192] *Id.*

[193] *See, e.g., NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 803 (D.C. Cir. 2007) ("*NSTAR*") (stating that reasonable rates are those "not materially exceeding the range needed to assure availability of the needed generating capacity.").

[194] *See NextEra* at 21; *NSTAR* at 803 (grid stability and reliability benefits do not eliminate requirement that costs be meaningfully considered in setting just and reasonable rates); *accord TransCanada* at 13 (finding that sellers in a cost-based program are not "free to command high prices" in the name of reliability benefits that are not adequately explained and weighed against the costs).

[195] NEPOOL Filing at 16.

explanation for the high costs consumers would be charged under the ESI Proposal, estimated at between $183 million and $466 million annually for the ESI products depending on the severity of weather.[196] While the Commission need not find that a program results in "net savings," it must explain the non-cost factors such as reliability that informed its rate setting decision.[197] ISO-NE provides no record upon which the Commission can make a reasoned finding that ESI's costs are justified.

iii. ESI's Cost Will Likely Be Higher Than the Impact Assessment Projects

The Impact Assessment includes consumer cost estimates that likely understate the ESI program's actual costs. Several features of the analysis drive this outcome.[198] First, the model contained structural limitations.[199] For example, the ESI Proposal includes two RER products while the Impact Assessment models just one, with the higher quality reserve product compensated at less than its actual value.[200] A number of other examples highlight these limitations: (1) the model represents the New England system as a whole, with no transmission constraints,[201] (2) net imports from neighboring systems are aggregated and lumped together

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196 *See supra* n. 19.

197 *See Advanced Energy* at 660-661.

198 NESCOE's perspective on the Impact Assessment should not be understood as a criticism of ISO-NE's consultants or technical staff, who diligently worked to develop a new model under significant time constraints.

199 *See, e.g.,* Impact Assessment at 75 ("The model does not consider a complex set of contingency events, does not account for transmission topology, and does not consider plant commitment, dispatch and other intertemporal limits to plant operations (e.g., minimum run time and minimum down time).").

200 *Id.* at 18 (stating that a single RER product is modeled) and n. 14 ("This modeling assumption will . . . compensate all resources that provide the RER90 or RER240 product at a single price that . . . may therefore understate the compensation to resources.")

201 *Id.* at 15, 75; *see id*. at n. 9.

with renewable resource production,[202] and (3) the model solves for each hour of the day, while the current ISO-NE markets re-dispatch every five minutes.[203]

Second, the model uses simplified assumptions to reflect energy market dynamics. The analysis is sensitive to the assumption that dual-fuel and oil-fired resources will, in response to ESI, increase initial fuel oil inventories and replenish inventories more often relative to current market rules.[204] In fact, all inputs are assumed and there are no dynamic market responses from fuel or infrastructure market participants (*e.g.*, natural gas or LNG suppliers) or neighboring control areas.[205] To the extent the analysis has overestimated the assumed fuel inventory management response to ESI, the costs to consumers may be understated by tens to hundreds of millions of dollars per winter.[206]

Third, the results of the Impact Assessment may not be technically feasible. They did not account for "unit-specific environmental permit requirements that may limit the circumstances in which certain units with dual-fuel capability can operate on alternate fuels."[207] Since actual air permit limitations were not within the scope of the analysis, dual-fuel and oil-fired resources

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[202] *Id.* at 22-23. Battery and pumped storage are also lumped together. *Id.* at n. 54.

[203] *Id.* at 15 and 41.

[204] *Id.* at 39. To examine the sensitivity of the results to this critically important assumption, the Impact Assessment includes a scenario where the ESI Proposal has been implemented but fuel oil inventory assumptions were the same as under the current market rules. *Id.* at 67.

[205] *Id.* at 87-88; *see id* at 22 ("[N]on-price-responsive imports are modeled as a fixed quantity of imported energy in every hour.") and 111 (Non-price-responsive connection points include Northport/Norwalk, Cross-Sound Cable, Hydro Quebec Phase I/II, and Shoreham.).

[206] The significant difference in consumer costs between the scenarios with and without the incremental oil assumed in response to ESI shows how sensitive the results are to this assumption. Under severe or frequently stressed winter conditions, the estimated consumer cost of ESI increased from \$132 million to \$398 million per winter, an increase of 200%, when the same level of oil inventories is assumed. Similarly, under moderate or extended stressed winter conditions, the estimated consumer cost of ESI increased from a savings of \$62 million per winter to a cost of \$226 million, an increase of over 450%, when the oil inventory assumptions are the same. The impact of this assumption has less of an effect under mild or infrequent stress winter conditions, increasing in cost from \$35 million to \$40 million per winter. Impact Assessment at 45, 69, 82, 86, and 97-98.

[207] *Id.* at n. 22.

were permitted to operate beyond legal requirements, and the model was not required to select the next available, and higher priced, resources.[208] For all of these reasons, the scope limitations and approach taken in the Impact Assessment lead to results that demonstrably understate ESI's costs.

iv. The Commission Should Continue to Safeguard Consumers From Unnecessary Costs Consistent with Actions on Prior ISO-NE Winter Reliability Programs

Only several years ago, the Commission rejected ISO-NE's short-term approach to incentivizing advanced fuel arrangements because, like the ESI Proposal, it deviated from the scope of the Commission's direction and imposed costs without providing commensurate reliability benefits.[209] Through the ESI Proposal, ISO-NE "would condemn us to repeat the past . . . as though we remembered nothing from the first showing."[210] The Commission must once again redirect ISO-NE's approach to fuel security.

In that earlier proceeding, ISO-NE and NEPOOL filed with the Commission alternative proposals to address system reliability over the three subsequent winter periods ("Winter Program III").[211] The primary difference between the ISO-NE and NEPOOL proposals concerned eligibility to participate in the winter program, with ISO-NE's proposal expanding

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[208] *Id.* at 116-117. After the analysis was completed, the Impact Assessment compared the air emissions results to current law in Massachusetts and found that "total emissions would exceed [the Massachusetts CO_2 Cap of 7.38 MT in 2025] amount in all combinations of winter and non-winter month Cases" under assumed allowance prices. *Id.* Apparently, if the hypothetical future winter were *mild*, and Massachusetts CO_2 allowance prices were $5 higher than assumed, the modeling suggests that power sector air emissions in Massachusetts may fall within current CO_2 cap levels. However, in *none* of the non-mild winter cases (i.e., when prolonged cold weather leads to natural gas infrastructure and supply constraints) did power sector air emissions meet the Massachusetts CO_2 Cap in the Impact Assessment.

[209] Winter Program III Order at P 47.

[210] *Sessions v. Dimaya*, 138 S. Ct. 1204, 1223 (2018).

[211] Winter Program III Order at P 1. The filing was made pursuant to a so-called "jump ball" provision of the Participants Agreement between ISO-NE and NEPOOL, whereby the Commission considers the proposals concurrently and with the same legal weight. *Id.* at n. 2.

eligibility to all resources with "on-site" fuel (*e.g.*, nuclear, coal-fired).[212] ISO-NE believed that the Commission directed it to "work to expand any winter reliability program to include all resources that can supply the region with fuel assurance."[213]

The Commission accepted the NEPOOL proposal. It found that "[w]hile ISO-NE expanded the types of resources eligible to participate in the program, the record does not reflect that including the additional resource types under the same general program principles will incent any additional fuel procurement."[214] The Commission further stated that "although ISO-NE asserts that the expectation of a three-year payment stream might incent the additional resources to invest in their assets more generally, we find that this potential result is beyond the scope of the program, which is designed particularly to ensure reliability *during the winter* by incenting market participants to provide additional reliability services that they would not have provided otherwise."[215] The Commission was thus clear: consumer payments must be commensurate with the reliability provided and ISO-NE's expansion of the program exceeded its direction.

With ESI, ISO-NE repeats the same fundamental error it made with Winter Program III. It fails to demonstrate that the expected incremental reliability benefits of its proposed design are worth its high costs. The Commission should reject the ESI Proposal for the same guiding principle, reflected in the FPA's prohibition against excessive consumer costs, that it applied in declining ISO-NE's request to approve an expanded winter program.

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[212] *Id.* at P 9.

[213] *Id.*

[214] *Id.* at P 47.

[215] *Id.* (emphasis in original) (citation omitted).

The Commission also focused on the need to protect New England consumers from paying excessive costs in connection with ISO-NE's first winter reliability program, Winter Program I. Just last month, the Commission upheld the results from Winter Program I in part because "ISO-NE considered the tradeoff between reliability and customer costs."[216] As ISO-NE explained, "it evaluated the marginal cost of each incremental quantity and determined that the reliability benefits from the [p]rogram met or exceeded [p]rogram costs at the chosen procurement level."[217] ISO-NE "was authorized to procure additional quantities, which would have improved reliability, but judged that the incremental reliability benefits from additional procurement were not worth the additional costs."[218] On remand from the D.C. Circuit, the Commission credited ISO-NE's exercise of this discretion in affirming Winter Program I costs as just and reasonable.[219]

The Commission should reject the ESI program as inconsistent with precedent and as unjust and unreasonable. Alternatively, if the Commission accepts the ESI Proposal, it must explain why it departed from precedent requiring that costs be commensurate with reliability benefits provided.[220] It would be arbitrary and capricious for the Commission to reverse its prior positions without sufficiently explaining why it has changed course and ISO-NE has provided no basis for the Commission to do so.[221]

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216 Winter Program I Order at P 63.

217 *Id.* at P 34; *see id.* at P 63.

218 *Id.* at P 34.

219 *Id.* at P 63.

220 *See, e.g.,* Winter Program III Order at P 47; *ISO New England Inc. and New England Power Pool Participants Committee*, 147 FERC ¶ 61,172 at P 23 (2014) ("PFP Order") (finding that consumers cannot be forced "to pay for capacity without receiving commensurate reliability benefits.").

221 *See* 5 U.S.C. § 706(2)(A); *New Eng. Power Generators Ass'n, Inc. v. FERC*, 881 F.3d 202, 211-213 (D.C. Cir. 2018) ("*NEPGA*") (finding that the Commission did not engage in reasoned decision-making because it "failed to respond to the substantial arguments put forward . . . and failed to square its decision with its past precedent."); *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014) ("It is textbook

v. ISO-NE's Unconventional Approach to Ancillary Services Exposes Consumers to Additional Unwarranted Costs

Mr. Wilson testifies that "new, complex market designs can lead to unintended consequences that generally raise the cost to consumers."[222] The ESI program "is a novel and untried market design approach, and . . . there is risk of unanticipated and unintended outcomes due to some combination of market design shortcomings and participant conduct to exploit those flaws."[223] Mr. Wilson discusses various ways in which the ESI program, due to "compromises or simplifications necessary to resolve various design trade-offs," will result in inefficiencies and unwarranted consumer costs.[224]

The ESI construct, for example, would increase consumer costs as a result of risk premiums—related to the energy option and settlement risk inherent in ESI—that resources would include in their energy option offers.[225] Mr. Wilson testifies that this type of risk premium does not exist in more conventional day-ahead ancillary service approaches or in ISO-NE's current market design.[226] He provides additional examples of inefficiencies resulting from ESI's settlement design and offer parameters.[227]

Rather than place consumers at risk in implementing an experimental design, ISO-NE could explore a seasonal forward market construct, as it has committed to doing,[228] and consider

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administrative law that an agency must provide a reasoned explanation for departing from precedent or treating similar situations differently.") (cleaned up).

222 Wilson Testimony at 58.

223 *Id.* at 54.

224 *Id.* at 55; *see id*. at 11-12, 54-59.

225 *Id.* at 11, 16-17, 34-38, 55-58.

226 *Id.* at 11, 22.

227 *Id.* at 55-58.

228 Transmittal Letter at 71-72.

how such a design could work together with more conventional and proven approaches to procuring day-ahead reserves.[229] ISO-NE redefined the problem as "misaligned incentives" and prematurely retreated into its ESI design instead of working to understand the ability of such a seasonal forward market to improve the region's fuel security cost-effectively.[230] Such a seasonal mechanism could include an auction held months or even years ahead of a delivery period to incent suppliers to make forward fuel arrangements.[231]

ISO-NE never fully examined the potential for a seasonal forward market, together with more established approaches to ancillary services, to provide the incentives it believes are needed to promote advance energy supply arrangements because it instead elected to focus on the ESI design. ISO-NE fails to justify the risk premiums and other costs associated with implementation of such a novel and untested design. To the extent ISO-NE now commits to developing a seasonal forward procurement, it appears that such a program would be layered upon an unproven ESI experiment.

B. In the Alternative, the Commission Should Direct ISO-NE to Adopt the Tailored Changes Reflected in the NEPOOL Proposal to Help Limit Consumer Cost Risks While Not Materially Affecting the ESI Program's Reliability Objectives

For the reasons discussed above, the Commission should reject the ISO-NE Filing as contrary to the July 2018 Order, the FPA, and Commission precedent. However, if the Commission does not reject the ISO-NE Filing, NESCOE respectfully requests that the Commission accept the ESI Proposal subject to further compliance and direct ISO-NE to adopt

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229 *See generally* Technical Session 2 (presenting ISO-NE's understanding of how other RTOs satisfy day-ahead requirements); *see* Wilson Testimony at 9 and 21-22 (describing conventional approaches to procuring day-ahead ancillary services).

230 *See* Wilson Testimony at 21 ("A conventional approach . . . combined with a seasonal or longer forward construct to provide incentives for energy secure resources and arrangements, is an alternative that potentially could be more effective and lower cost.").

231 *See* Transmittal Letter at 72 (describing conceptual details of a potential seasonal forward market).

the NEPOOL Proposal. As explained below, the NEPOOL Proposal would better align the ESI program with the Commission's directives while not materially affecting ISO-NE's reliability objectives. It would also make a critical difference in limiting the cost risks that consumers face under ESI, including helping to address some of the risks that Mr. Wilson identified in connection with market power and design inefficiencies.[232]

1. The RER Quantity Should Be Set to Zero in the Non-Winter Months

a. ISO-NE Fails to Demonstrate that RER Addresses a Fuel Security Problem Existing Outside the Winter Months

As discussed above, the Commission's directives in the July 2018 Order are limited to fuel security in the *winter period*. The NEPOOL Filing additionally explains that the ISO-NE Filing fails to show that RER is needed outside the winter months.[233] NEPOOL's expert testimony discusses how the Impact Assessment indicated potential operating reserve shortages solely in the winter months (and only for three hours despite simulations analyzing over 150,000 hours in the winter and non-winter period).[234] The NEPOOL Filing also explains how NERC and NPCC standards provide no justification for applying RER beyond the winter months, and it confirms that fuel security risks are a winter issue.[235] NESCOE agrees that the NEPOOL Proposal's focus on RER in the winter months is more closely aligned with the winter fuel security concerns that the Commission relied upon in invoking its section 206 authority in the July 2018 Order.[236]

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[232] *See* Wilson Testimony at 54-58.

[233] NEPOOL Filing at 19-24.

[234] *Id.* at 19-20 (citing Griffiths Testimony at 13-20).

[235] NEPOOL Filing at 20-22; Daly Testimony at 4-6 (explaining that "concerns about fuel security are limited to the most severe peak winter days" and discussing pipeline constraints as a winter problem).

[236] NEPOOL Filing at 23-24.

b. Consumers Would Be Charged a High and Unjustified Premium for RER Costs Over Non-Winter Months

The Impact Assessment estimates that consumers would be charged between \$41 million and \$69 million each year in connection with ISO-NE's procurement of RER in the non-winter months, depending on weather.[237] It explains that these additional costs would go toward additional FER payments and day-ahead energy option payments.

ISO-NE claims that its RER product is needed in all months of the year. It offers four reasons to support its application of RER to the non-winter months. None of these asserted justifications have merit or warrant the substantial charges that consumers are expected to incur.

First, ISO-NE argues that the failure to pay for reserves to meet restoration requirements "contributes to the fundamental energy security 'misalignment' problem."[238] As discussed above, ISO-NE has not demonstrated that there is a misalignment problem in the non-winter months when fuel is more readily available. Moreover, the NEPOOL Filing rebuts any claim that such a misaligned incentives issue exists outside the winter period.[239]

Second, ISO-NE claims that RER is needed in all months because "the underlying NERC and NPCC standards supporting these capabilities apply throughout the year, and [ISO-NE's] ability to meet them may grow more uncertain in non-winter months as the power system evolves to include more just-in-time energy sources."[240] Again, ISO-NE has not established a nexus between the misaligned incentives problem it identifies and the non-winter months: there is no record evidence that ISO-NE is at risk of non-compliance with NERC or NPCC standards

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[237] Impact Assessment at 101-102.

[238] Transmittal Letter at 41-42.

[239] *See, e.g.,* Daly Testimony at 4-6.

[240] Transmittal Letter at 42.

related to reserve restoration due to the inability of resources to procure fuel.[241] Moreover, the fact that the NERC and NPCC standards apply year round does not support ISO-NE's argument because, as discussed earlier, these standards do not require the procurement of RER. The NEPOOL Filing further explains how the Impact Assessment demonstrates that limiting the procurement of RER to the winter months is not projected to have any impact on the potential for reserve deficiencies.[242]

Mr. Griffiths highlights the unnecessary premium that RER would charge consumers in the non-winter months. He testifies that, in light of the decreasing duration and magnitude of reserve deficiencies in New England, "RER would offer a form of expensive insurance to ameliorate a risk that is immaterial in the first place."[243] Mr. Bergeron offers a similar perspective: "Given the historically infrequent reserve deficiency occurrences, the various actions available to replenish the reserves, and the fact that no other RTO has a replacement reserves ancillary service that in effect pre-purchases reserves to replace reserves, the unproven benefits of RER do not appear to outweigh the costs for the service."[244] ISO-NE's procurement of RER beyond the winter period would also "lead to an excessive [day-ahead ancillary services] quantity and exacerbate the inefficiency of the ESI design."[245]

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[241] In fact, as Mr. Bergeron testifies, "during the stakeholder process ISO-NE staff confirmed that ISO-NE is currently in compliance with all NERC and NPCC reliability requirements and is operating completely within the parameters of its own Operating Procedures." Bergeron Testimony at 2.

[242] NEPOOL Filing at 19-20, 24.

[243] Griffiths Testimony at 16-17; *see* Bergeron Testimony at 7 (stating that for the period 2007 through 2019, "reserve outages have averaged 8.25 hours per year or 0.09% of annual hours.")

[244] Bergeron Testimony at 7.

[245] Wilson Testimony at 18; *see id.* at 72. Mr. Griffiths also testifies that ISO-NE has not demonstrated that procuring RER outside the winter period would provide market efficiency benefits. Griffiths Testimony at 19-20.

Moreover, ISO-NE's existing market construct currently incentivizes, rewards, or imposes obligations in connection with reserves, many mechanisms over. As a starting point, it is incorrect to claim that suppliers are providing a service for free—resources are paid "if they are called to provide energy to restore reserves in" real-time.[246] In any event, current obligations and multiple sources of revenue include:

- **Forward Capacity Market ("FCM") Performance Obligation:** Under FCM rules, "a resource with a Capacity Supply Obligation must offer into the day-ahead energy market, leave that offer open throughout the operating day, and follow the ISO-NE dispatch instructions."[247] This obligation extends to system reserve deficiency events.[248] The requirement "to follow ISO-NE's dispatch instructions is, in effect, an obligation to provide energy or reserves subject to the resource's operating parameters, and the Commission has explicitly referred to New England capacity resources' energy market obligations as 'performance' obligations."[249] If a resource "fail[s] to meet any of these energy market obligations," the Commission may consider the inability to provide energy or reserve a violation of the Tariff.[250]

- **Operating Reserve Payments:** Suppliers are compensated under the Tariff for providing operating reserves in real-time with payments up to $1000/MWh and $1500/MWh for ten and thirty minute reserve deficiencies, respectively.[251]

- **Real-Time Energy Market Payment:** In addition to operating reserve payments, compensation to suppliers in real-time also incentivize reserves when scarcity conditions arise. When the quantity ISO-NE procures from the day-ahead energy market deviates from the quantity needed in the operating day, suppliers not committed in the day-ahead market but that operate in real-time receive an energy payment set to the Real-Time Locational Marginal Price.[252]

- **Fast-Start Pricing:** Under its "fast start" pricing mechanism, ISO-NE incentivizes resources "that can be started in thirty minutes or less, that have a minimum run time of one hour or less, and that have a minimum down time of one hour or less."[253] This

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[246] Wilson Testimony at 74.

[247] PFP Order at P 38 (citations omitted).

[248] *Id.*

[249] *Id.* (citation omitted).

[250] *Id.* (footnote omitted).

[251] *See* PFP Order at P 27; Cavanaugh Testimony at 6.

[252] *See* Market Rule 1, Section III.2.

[253] Cavanaugh Testimony at 13; *see* Fast Pricing Order at 1.

allows ISO-NE to dispatch and commit these resources in real-time "during stressed system conditions when reliability risk is higher."[254]

- **PFP:** ISO-NE proposed PFP to provide financial incentives for resource performance when reserves are deficient.[255] PFP implements a two-settlement market design, where capacity resources receives a Base Capacity Payment and a Capacity Performance Payment.[256] The Capacity Performance Payment rewards a resource that supplies more than its share of energy and reserves during scarcity conditions and penalizes a capacity suppliers that provide less than its share.[257] Those payments are calculated using an administratively-set Capacity Performance Payment Rate ("PFP Rate").[258] ISO-NE set the PFP Rate as: $2,000/MWh in the June 1, 2018 through May 31, 2021 period; $3,500/MWh for the June 1, 2021 through May 31, 2024 period; and, starting June 1, 2024, $5,455/MWh going forward.[259] PFP bonus payments are additive to the compensation provided under the other mechanisms listed above. ISO-NE began implementing PFP in June 2018.

The Cavanaugh Testimony explains that ISO-NE's existing incentives, "provide ample motivation for resources to secure fuel and respond to contingencies consistent with NERC and NPCC criteria[.]"[260] Mr. Griffiths echoes that point: "RER is disproportionately expensive and has the added drawback of being duplicative of other market products today."[261] He testifies that existing mechanisms already "price reserve restoration into the markets" and describes how ISO-NE's asserted need for PFP closely mirrors ESI's objectives.[262]

Additionally, the EMM has explained how PFP—ISO-NE's hallmark program for incenting energy and reserves when needed most—already provides a substantially higher rate

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254 Cavanaugh Testimony at 13. Mr. Cavanaugh also discusses Opportunity Cost Adder incentives. *See id.* at 12-13.

255 PFP Order at PP 3-4, 29.

256 *Id.* at PP 4-6

257 *Id.* at P 6.

258 *Id.*

259 *Id.* at P 44.

260 Cavanaugh Testimony at 6, 12; *see* Wilson Testimony at 74.

261 Griffiths Testimony at 28.

262 *Id.* at 28-30.

than is necessary to induce performance for most scarcity events and may lead to inefficient actions.[263] In June 2019, based on the first (and still to date only) PFP event that occurred one year earlier, the EMM determined that "[t]otal incentives provided by the real-time market and the PFP were large" and observed that settlements topped $4,700/MWh "although reserves were above 60% of requirements."[264] The EMM explained that the expected value of lost load "during the event ranged from $700 to $1,000 per MWh, far lower than the actual rate of compensation of $3000 to $4700 per MWh."[265] This compensation reflected combined revenues from real-time energy prices and Capacity Performance Payments. The EMM recommended against phasing in the increased PFP Rate beginning in 2021 and stated that the rate should be modified to "rise with the reserve shortage level" to ensure that resources are not over-compensated in shallower events or under- compensated in more serious events.[266] Thus, the EMM recommended a path forward that would set the compensation level to be more commensurate with the value of lost load or, said differently, its MRV.

ISO-NE's suite of existing market mechanisms undercuts ISO-NE's claimed need for RER in the non-winter months. Without a clear demonstration of need, RER effectively adds an unnecessary and costly layer of insurance for securing reserves. NESCOE agrees with NEPOOL that ISO-NE is effectively buying "a very high-premium, gold-plated insurance policy that is not

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[263] Potomac Economics, ISO-NE External Market Monitor, 2018 Assessment of the ISO New England Electricity Markets, June 2019, NEPOOL Participants Committee Meeting, June 25-27, 2019, at 44, available at http://nepool.com/uploads/NPC_2019062527_Composite5_p2.pdf.

[264] David B. Patton, Ph.D., Potomac Economics, ISO-NE External Market Monitor, Highlights of the 2018 Assessment of the ISO New England Markets, June 25, 2019, NEPOOL Participants Committee Meeting, June 25-27, 2019, at Slide 36, available at http://nepool.com/uploads/NPC_2019062527_Composite5_p2.pdf.

[265] *Id.* at Slide 38.

[266] *Id.*

needed to address regional fuel security concerns and that is not otherwise justified under the statutory just and reasonable standard."[267]

Third, to the extent ISO-NE contends that RER is needed outside the winter period because a growing number of intermittent resources are expected to come on-line,[268] that assertion is unaccompanied by sufficient evidentiary support. Moreover, the July 2018 order, which relies on the OFSA and Mystic Retirement Studies, does not specifically identify the intermittency of clean energy resources as a source of the region's fuel security challenges.[269] As discussed above, the region is currently engaged in collaborative discussions that include the development of a power system study to consider operational needs taking into account future system conditions such as state energy and environmental requirements. Assuming the need for RER in the non-winter period to address a projected growth in renewable energy unnecessarily, and inexplicably, leaps over this process.

Finally, ISO-NE claims RER should be procured throughout the year because "the design is risk responsive" and consumer costs will change based on the level of energy security risk.[270] The potential for consumer costs to fluctuate is hardly a demonstration that the rate is just and reasonable. In fact, Mr. Wilson testifies that consumers are at risk of being overcharged when

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[267] NEPOOL Filing at 29.

[268] *See* Transmittal Letter at 9, 26-27, 42; Brandien Testimony at 4, 24-25; ESI White Paper at 11.

[269] Notably, the OFSA and Mystic Retirement Studies did not assume any additional new clean energy resources after the relevant Forward Capacity Auction. *See, e.g.,* Memo from NESCOE to ISO New England, Preliminary Input – Fuel Security Analysis, Feb. 15, 2018, at 1 (stating that "13 of the 23 scenarios [in the OFSA] assume that the New England states will *not* meet statutory renewable and clean energy requirements. Without the future energy contributions from the resources state laws require, the [OFSA] likely overstates the region's future fuel-security risk. Over time, the New England states have satisfied their statutory requirements so assuming they will [continue to do so] going forward is reasonable."), available at http://nescoe.com/wp-content/uploads/2018/02/FuelSecurityAnalysisComments_15Feb2018.pdf. The remaining 10 of 23 scenarios that included various levels of increased renewable resources resulted in lower fuel security risk metrics than their counterparts. *See* ISO New England, Operational Fuel-Security Analysis, Jan. 17, 2018, at 56, available at https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[270] Transmittal Letter at 42.

the total ESI quantity is expanded to include RER and that the MRV of RER procured in the non-winter months would be especially low.[271]

Consumers should not have to incur tens of millions of dollars in annual costs to buy RER in the non-winter months. The record in this proceeding fails to provide support for the Commission to find that RER's benefits during the non-winter season justify the substantial investment ISO-NE would require of consumers.[272]

2. The RER Quantity Should Not Include an Allowance for Load Forecast Error

ISO-NE proposes to include an allowance for load forecast error in the quantity of RER products procured.[273] ISO-NE states that "reliability standards require accounting for demand patterns and the use of reserves for load forecast errors" and that its "proposal formalizes in the market the operational capabilities relied on to address unanticipated demand pattern changes."[274] The quantity of RER that ISO-NE would procure to account for load forecast error is undefined. ISO-NE has deferred to a later stakeholder process "the detailed calculation for determining the amount" of load forecast error allowance.[275] ISO-NE's allowance for load

271 Wilson Testimony at 68; *see id.* at 72 (explaining the negative impact on efficiency that acquiring RER in the non-winter months would have).

272 *See* 5 U.S.C. § 706(2)(A); *NEPGA* at 210 ("The arbitrary-and-capricious standard requires [FERC] to 'examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.'") (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)); *Advanced Energy* at 660-661 (rejecting arguments that the Commission acted in an arbitrary and capricious manner because it "balanced the benefits of the revised rules against the increased costs and reached a reasoned judgment."); *see also NextEra* at 21 ("Setting a just and reasonable rate necessarily involves a balancing of the investor and the consumer interests.") (cleaned up); *accord TransCanada* at 13 (finding that sellers in a cost-based program are not "free to command high prices" in the name of reliability benefits that are not adequately explained and weighed against the costs).

273 *See* Transmittal Letter at 41.

274 *Id.* at 42.

275 *Id.* at 41.

forecast error would, according to ISO-NE's expert estimate, increase consumer costs by up to $99 million per year.[276]

Joining a supermajority of the region's stakeholders, NESCOE objects to ISO-NE's incorporation of load forecast error in setting the RER quantity. As NEPOOL states, ISO-NE's allowance for load forecast error "is vague, is not supported by any demonstrated fuel security need, and will add considerable unnecessary costs to consumers."[277] There are at least two reasons why the Commission should direct ISO-NE to remove the allowance for load forecast error from its proposal.

First, including load forecast error as part of the RER quantity procured compounds the excessive costs consumers would be charged under ESI. The first part of ISO-NE's proposed Tariff revisions for RER sets the quantity to what ISO-NE identifies as needed to meet NERC and NPCC reliability standards.[278] That input alone will likely buy more energy call options than is needed to meet system needs and fails to account for the diminishing MRV of the option quantity purchased, as discussed above.

The Impact Assessment illustrates the excess of including a load forecast error allowance in the RER quantity. The "RER Plus" scenario modeled in the analysis is a reasonable proxy for inclusion of the load forecast error allowance.[279] Under the Frequent Case, dual-fuel, combined

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276 Impact Assessment at 97 ("Compared to the Central Case ESI results, the additional RER increases payments by $99 million, $50 million and $16 million in the Frequent, Extended and Infrequent Cases, respectively.").

277 NEPOOL Filing at 3.

278 *See* Transmittal Letter at 38-40.

279 The "RER Plus" scenario sets the RER amount to 150% or 600 MWh greater than the central case. Impact Assessment at 87. While ISO-NE has yet to calculate the load forecast error amount, as discussed below, 600 MWh is well within the 200 to 2,400 MWh range that ISO-NE provided during the stakeholder process. *See* ISO New England, Energy Security Improvements: Market-Based Approaches, Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion, NEPOOL Markets Committee, Feb. 11-13, 2020, at Slide 12 ("LFE Presentation"), available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_ii_esi_rer_goal2_accounting_for_load_forecast_error.pptx.

cycle resources would realize a 22% increase in revenues with no incremental change in holding costs, a change in revenues from $5,577/MW to $6,831/MW.[280] For oil-only, combustion turbine generators (the majority of resources studied in the analysis), inclusion of the allowance could increase incremental revenues from $7,385/MW to $9,639/MW, a 31% gain, in the Frequent Case. Except for oil-only steam resources in the mild winter Infrequent Case, including a 600 MW load forecast error in the quantity of RER resulted in all dual fuel and oil-fired resource net revenues increasing by 22% to 85% with no corresponding increase in carrying costs.[281] These load forecast error incentives are *additive* to those provided under the analysis' baseline modeled winter scenario which, as discussed above, pays resources an order of magnitude more than the cost of securing fuel oil.

NESCOE agrees with NEPOOL that a load forecast error allowance adds an additional level of insurance that provides little protection in exchange for its significant cost.[282] It is a bad investment for consumers, making ESI's design inefficiencies more severe and charging unwarranted costs.[283]

Second, it is premature for ISO-NE to include this provision in its Tariff. ISO-NE has deferred the process of calculating a load forecast error amount to a later stakeholder process.[284] Stakeholders have not had a meaningful opportunity to understand how load forecast error would be determined.[285] ISO-NE presented its current approach to load forecast error late in the

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[280] *See* Impact Assessment at 122-123 (Tables 62-64).

[281] *Id.*

[282] NEPOOL Filing at 26-27.

[283] *See* Wilson Testimony at 18, 75-76.

[284] *See* Transmittal Letter at 41.

[285] *See* NEPOOL Filing at 25-26.

stakeholder process, after having considered and discarded two prior approaches.[286] The details matter. ISO-NE has noted that the quantities procured for load forecast error could run as high as 2,420 MWh,[287] potentially exceeding how much ISO-NE would procure for RER to address its core purpose of restoring reserves should a contingency event occur.[288]

The Commission should direct ISO-NE to remove the load forecast error allowance from the RER quantity. As proposed, it exposes consumers to unjust and unreasonable costs. ISO-NE has an opportunity, after meaningful stakeholder discussions, to propose the addition of a load forecast error allowance after it has demonstrated a need for that provision and provided foundational details regarding its calculation.

3. The ESI Proposal Should Include a Strike Price Adder to Encourage Greater Program Participation, Limit Supplier Risks, and Reduce Consumer Costs

The Commission should direct ISO-NE to modify the strike price value it proposes for the energy call options. The Strike Price Adder reflected in the NEPOOL Proposal is designed to reduce supplier risk and increase program participation which, in turn, should limit consumer cost exposure. Increasing participation and limiting cost risks are especially critical in the early years of ESI implementation given the potential for resources to exercise market power, uncertainty regarding supplier risk and costs, and the lack of historical data for a new program.

ISO-NE proposes to set the strike price at its forecast of the expected Real-Time Hub Price.[289] ISO-NE describes three guidelines it would apply in setting the price: (1) Known Values: participants must know the numerical strike price value before submitting their energy

[286] LFE Presentation at Slides 12-13.

[287] *Id.* at Slide 22.

[288] *See* Impact Assessment at 18 (describing how the analysis modeled a different value, “an assumed fixed requirement of 1,200 MW in each hour for both RER90 and RER240”) and 159-160 (Table 7-2) (listing total RER quantity as 1,350 MWh (3,650 MWh – 2,300 MWh)).

[289] *See* Transmittal Letter at 48; ESI White Paper at 78.

and ancillary service offers, (2) At the Money: the strike price should be "set at approximately the expected value of the energy price at which the options will settle," and (3) Accurate, within limits: when implemented, "small inaccuracies in setting the strike price precisely 'at the money' should not matter much."[290]

NESCOE agrees with NEPOOL that a $10/MWh adder to ISO-NE's proposed strike price achieves a critical balance between providing market incentives for resources and safeguarding against unnecessary consumer costs.[291] There are three reasons why the Strike Price Adder improves the ESI Proposal.

First, the Strike Price Adder helps protect against excessive consumer charges. It generally reduces both the magnitude and frequency of energy option strikes, which in turn should lower the risk premiums suppliers will include in their offers.[292] Lower cost and risk may "encourage greater participation by resources that might otherwise choose to not offer to provide" an ESI product.[293] The adder also helps to mitigate consumer cost impacts by reducing the frequency of energy option strikes that would result from forecasting errors. These inaccuracies, which cannot be entirely avoided, would result in many hours where "the strike price has been set well above or well below the . . . prices expected by market participants" (i.e., the "noise").[294] The Impact Assessment estimates that the Strike Price Adder could protect consumers from up to $15 million in charges for the winter period each year and up to $19 million in the non-winter months.[295]

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[290] *See* ESI White Paper at 73-77.

[291] NEPOOL Filing at 27-29.

[292] Wilson Testimony at 78.

[293] *Id.*

[294] *Id.* at 77-79.

[295] Impact Assessment at 98, 101; *see* Cavanaugh Testimony at 17.

Second, the Strike Price Adder would not materially undermine ISO-NE's fuel security objectives. Mr. Wilson's detailed analysis indicates that the Strike Price Adder "would eliminate many strikes when [real-time] prices are low (and energy security is not a concern), and would eliminate few strikes when [real-time] prices are high and the [e]nergy [o]ption incentives are desired to contribute to energy security."[296] Similarly, his analysis illustrates "that the Strike Price Adder mainly reduces the magnitude of [e]nergy [o]ption settlement in low-price hours when energy security is less of a concern, and with a much smaller impact in higher price hours."[297] The Wilson Testimony thus directly rebuts ISO-NE's claims that an adder could materially affect incentives.[298]

During the stakeholder process, the EMM expressed support for the $10/MWh adder. Based on its analysis, the EMM concluded that any reduction in settlement arising from the adder "would be a very small portion of the overall close-out costs during tight market conditions, so the increase in strike price is unlikely to have a significant impact on incentives to obtain fuel during periods when it would be most important for maintaining reliability."[299] The EMM continued: "As the strike price is raised, the reduction in close-out costs of not procur[ing] fuel would be offset by an increase in foregone profits of not procuring fuel (in the $10 range)."[300]

While ISO-NE expresses concerns that an adder would reduce incentives for resources to make fuel arrangements,[301] the EMM suggests that such concerns are overstated:

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[296] Wilson Testimony at 81-82.

[297] *Id.* at 83.

[298] *Id.* at 84-89.

[299] EMM Memo at 2.

[300] *Id.* at 3.

[301] *See, e.g.,* Transmittal Letter at 48; ESI White Paper at 100.

> - The overall net revenue impacts are very small, and they only account for a significant share of the impacts during moderate market conditions when reserve providers are less likely to materially impact reliability if unavailable.
>
> - Although the net revenue from covering may be reduced, it does not necessarily mean that the supplier will not provide reserves reliably. For example, a high cost oil-fired peaking unit may have a decreased incentive to cover (i.e., generate energy), but that does not mean that it is not providing reserves that the ISO can depend on to maintain reliability.[[302]]

In addition:

> While it is impossible to estimate the optimal amount by which the strike price should be increased, there is ample information to suggest that:
>
> - This change would not undermine the market and reliability benefits of satisfying reserve adequacy needs within the market, but
>
> - Would reduce the likelihood that the day-ahead ancillary services market would lead to excessive costs to consumers to during mild and moderate operating conditions.[[303]]

The EMM stated that "it will be important to assess the efficiency of the strike price level on an on-going basis."[304]

NESCOE agrees that the strike price can and should be evaluated with the benefit of experience. As previously noted, the Strike Price Adder is especially important in the early years of ESI implementation when no experience exists with the proposal and how various system conditions will affect its efficacy and the costs involved. The early years leave consumers particularly vulnerable to this lack of experience; they will pay the costs resulting from

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302 EMM Memo at 3.

303 *Id.*

304 *Id.*

inefficiencies and uncompetitive pricing if market power is not effectively restrained. The IMM can include a review of the strike price in its competitiveness assessment as part of the annual IMM review of the markets.[305] Critically, with the integration of the Strike Price Adder, consumers would benefit from some protection against such excessive costs pending review of the overall design.

Third, NESCOE agrees with NEPOOL that the $10/MWh strike price adder falls within the range of a just and reasonable rate.[306] ISO-NE's guidelines for setting the strike price illustrate how the calculation is more art than science.[307] There is no "magic" number by which the strike price should be increased to achieve the proper balance between incentives and consumer costs. However, for the reasons set forth in the EMM Memo, the NEPOOL Filing, and the Wilson Testimony, a $10/MWh adder falls within a range of reasonableness that is consistent with the FPA and Commission precedent.[308] NESCOE respectfully requests that the Commission direct ISO-NE to adopt the Strike Price Adder.

4. The Impact Assessment Confirms that Adopting the NEPOOL Proposal Would Not Undermine Incentives

The design enhancements reflected in the NEPOOL Proposal provide significant protections for consumers while not materially affecting the generous revenue streams that the Impact Assessment projects, which leave much room to spare. As described previously, the

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305 *See* Transmittal Letter at 6.

306 NEPOOL Filing at 28.

307 *See, e.g.,* ESI White Paper at 74 (describing guideline #2 as setting the strike price at an "approximate" and "expected" value and describing guideline #3 as being accurate "within limits" while noting that "small inaccuracies . . . should not matter much.")

308 *See Emera* at 20 ("Statutory reasonableness is an abstract quality that allows a substantial spread between what is unreasonable because too low and what is unreasonable because too high.") (cleaned up); *NextEra* at 25 (rejecting claims that the Commission acted unreasonably in accepting a 200 MW cap for capacity market renewable resource exemption because it was based on "the best estimate of load growth, which the Commission "acknowledged . . . could be more or less than" ISO-NE expected while crediting ISO-NE commitment to revisit the cap if necessary).

Impact Assessment discusses how the incentives that suppliers would receive under ESI could "far outweigh" and "far exceed" these additional holding costs.[309] The Strike Price Adder would have a *de minimis* effect on these incentives while the RER changes would have little to no impact.

The Impact Assessment modeled the estimated effect of a $10/MWh strike price adder on the revenues that suppliers would receive from ESI. For example, in a moderate or severe winter, the Extended and Frequent Cases, the Strike Price Adder would reduce incremental revenues by only 1%-7% for dual-fuel resources, providing revenues that are still at least 18 times greater than the additional costs of holding oil at the end of winter.[310] In a more extreme example, the same strike price scenario in a severe winter would reduce incremental revenues for dual fueled, combined cycle resources from $5,577/MW to $5,537/MW at a static additional holding cost of $14/MW – a diminution of less than 1% for a resource than can earn 398 times its additional holding costs per megawatt.[311] NESCOE has been consistent in acknowledging that the Strike Price Adder could reduce incentives, but the Impact Assessment shows that the incentives to participate in ESI would remain staggeringly high even with the Strike Price Adder.

Regarding load forecast error, as discussed above, the "RER Plus" scenario represents a reasonable proxy for inclusion of that program element. Such inclusion, explained above, takes an already stunning incentive level to new heights. Eliminating the additive revenues that the load forecast error allowance would provide does not undermine the already substantial incentives that the Impact Assessment projects.

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[309] Impact Assessment at 52.

[310] *See id.* at 121-123.

[311] *Id.* at 122; *see* Griffiths Testimony at 31.

Regarding the limitation of RER to the winter months, the revenues that suppliers are projected to receive in the winter scenarios that the Impact Assessment examined would, of course, be unchanged. RER would operate in the same way during the winter period as it would under the ISO-NE design (except for load forecast error allowance).[312] For the non-winter months, as discussed earlier, eliminating RER would not have a material adverse effect on ISO-NE's fuel security objectives because there are no demonstrated impediments to suppliers making fuel supply arrangements during this period.[313]

IV. CONCLUSION

If the Commission ultimately finds that the existing Tariff is unjust and unreasonable, the ESI Proposal fails to adequately address the fuel security concerns underlying the July 2018 Order and is not a just and reasonable replacement rate. For the reasons stated herein, NESCOE urges the Commission to reject the ISO-NE Filing. If the Commission does not reject the filing, NESCOE respectfully requests that the Commission only accept it subject to further compliance and that it require ISO-NE to adopt the changes reflected in the NEPOOL Proposal.

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[312] *See, e.g.,* Griffiths Testimony at 17 (stating that the NEPOOL Proposal would "not change winter period operation of ESI.").

[313] *See also id.* at 14-15 (explaining how the Impact Assessment confirms that removing RER in the non-winter period "will not reduce reliability compared to ISO-NE's proposal.").

Respectfully submitted,

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Date: May 15, 2020

CERTIFICATE OF SERVICE

In accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day served by electronic mail a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Cambridge, Massachusetts this 15th day of May, 2020.

/s/ Jason Marshall
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Attachment A

Testimony of James F. Wilson

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)	Docket Nos. EL18-182-000
	)	ER20-1567-000

PREPARED TESTIMONY OF JAMES F. WILSON IN SUPPORT OF THE PROTEST OF THE NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

MAY 15, 2020

**PREPARED TESTIMONY OF JAMES F. WILSON
IN SUPPORT OF THE PROTEST OF THE
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY**

CONTENTS

PREPARED TESTIMONY OF JAMES F. WILSON IN SUPPORT OF THE PROTEST OF THE NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

I. INTRODUCTION AND QUALIFICATIONS

Q 1: Please state your name, position and business address.

A: My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814.

Q 2: Please describe your experience and qualifications.

A: I have thirty-five years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission ("Commission" or "FERC"), state regulatory agencies, and U.S. district court. I have a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University.

I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, New York, MISO, Russia, and other regions. I have also been involved in natural gas pipeline, storage, distribution, procurement and market issues in regions across North America. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

II. PURPOSE AND SCOPE OF AFFIDAVIT

Q 3: On whose behalf are you testifying in this proceeding?

A: I prepared this affidavit on behalf of the New England States Committee on Electricity, Inc. ("NESCOE"). NESCOE is the Regional State Committee for New England and is governed by a board of managers appointed by the Governors of the six New England states. Its stated mission is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest reasonable cost over the long-term, consistent with maintaining reliable service and environmental quality.

Q 4: Please summarize the purpose of your affidavit.

A: My assignment was to evaluate the ISO New England ("ISO") Energy Security Improvements ("ESI") filing ("ESI Filing") and supporting testimony in this proceeding, and the alternative proposal supported by the New England Power Pool ("NEPOOL") Participants Committee ("NEPOOL Alternative"), and provide my evaluation and recommendations. The ISO ESI proposal is supported by the affidavits of Peter T.

Brandien, Matthew White, and Todd Schatzki of Analysis Group, a Whitepaper[1] supported by the White affidavit, and an Impact Assessment supported by the Schatzki affidavit.[2] The NEPOOL Alternative is supported by comments filed by NEPOOL on April 24, 2020, and affidavits by David A. Cavanaugh, James G. Daly, and Benjamin W. Griffiths.[3]

Q 5: How is your affidavit organized?

A: The next section of my affidavit summarizes my evaluation of the two variants of the ESI proposal, and provides my recommendations. Section IV evaluates the core ESI market design element, the day-ahead Energy Option. Section V provides a detailed discussion of the main concerns raised by the ESI proposal. Finally, Section VI evaluates the changes to the ESI proposal reflected in the NEPOOL Alternative.

III. SUMMARY AND RECOMMENDATIONS

Q 6: Please briefly describe the energy security problem that led the ISO to put forward its ESI proposal.

A: The general concern is whether the ISO New England wholesale markets provide sufficient incentives for market participants to take actions that will result in the desired level of energy security. The concerns can be understood as pertaining to the incentives and actions in two time frames:

1. *Short term actions (hours and days ahead):* Under circumstances that challenge energy security (such as during an extended cold snap), will resource owners have

[1] Matthew White et al, ISO New England, *Energy Security Improvements: Creating Energy Options for New England,* April 15, 2020 ("Whitepaper").
[2] Todd Schatzki et al, *Energy Security Improvements Impact Assessment*, April 2020 ("Impact Assessment").
[3] NEPOOL Participants Committee, *Comments in Support of the NEPOOL-Approved ESI Proposal*, April 24, 2020, Docket Nos. EL18-182-000 and ER20-1567-000.

sufficient incentives to manage scarce fuel stocks efficiently and make use of available opportunities to replenish?

2. *Longer term actions (season- to years-ahead):* Will resource owners have sufficient incentives to invest before the winter in higher oil inventory levels, liquefied natural gas ("LNG") cargoes, firm gas transportation commitments, maintaining fuel secure generating capacity, and other actions that will result in the desired level of energy security?

A. THE ESI PROPOSAL

Q 7: Please outline the ISO's ESI proposal.

A: The ESI proposal focuses on the short-term markets and incentives – it would make changes only to the ISO's Day-Ahead ("DA") markets. Under the proposal, the ISO would acquire a new DA AS product in quantities representing three categories of ancillary services ("AS"):[4]

1. Generation Contingency Reserve ("GCR"), operating reserves to respond to contingencies;
2. Energy Imbalance Reserve ("EIR"), based on the ISO's forecast, to prepare the system to meet expected demand conditions during the operating day; and
3. Replacement Energy Reserve ("RER"), to ensure replacement energy will be available to restore depleted operating reserves.

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[4] ESI Filing p. 21.

The ISO states that the proposal ensures that the market produces a reliable next-day Operating Plan, and compensates suppliers for the services the ISO relies on in preparing those plans.[5]

Q 8: Before getting further into the details of the proposal, please comment on the scope of the ESI proposal.

A: In proposing changes only to the DA market, the ESI proposal is notable for some things it does <u>not</u> include:

1. There is no proposal for a seasonal or longer forward market mechanism, although ISO suggests it may develop and propose one in the future.[6] The ESI proposal also does not include a multi-day ahead market to coordinate and optimize resources over a multi-day horizon, an idea that the ISO had put forward earlier in the stakeholder process.[7]
2. The ESI proposal does not change the products or final quantities of energy or AS ISO acquires in its real-time ("RT") markets; the proposed changes are to the DA markets.
3. The ESI proposal does not involve an explicit (or implicit) reliability standard or criterion related to energy security.

Specifically, as discussed further later in my affidavit, the ISO believes its proposed market design changes correct an incentive problem in the DA market such that, with

[5] ESI Filing p. 22.
[6] ESI Filing p. 71.
[7] See, for instance, Matthew White and Christopher Parent, ISO New England, *Energy Security Improvements: Market Solutions for New England,* presentation at the July 15, 2019 Staff-led public meeting in FERC Docket No. EL18-182 et al, slides 31-37.

ESI, market participants will find additional actions that support energy security profitable, and undertake them voluntarily.

Accordingly, the ESI proposal's market design changes are different from, and in some ways less than, what many stakeholders hoped and feared early in the stakeholder process. In particular, there was some thought that the ISO would propose a mandatory seasonal or years-forward construct, with the forward procurement quantities driven by a new reliability standard for energy security. That approach would parallel the ISO's approach to capacity resource adequacy: the ISO operates a Forward Capacity Market ("FCM") because it believes the energy and ancillary services markets by themselves do not provide adequate incentives to meet the desired level of resource adequacy. The ISO is not proposing a new or modified reliability standard that considers energy security.

Q 9: Please comment on the concept of acquiring AS in the DA market.

A: Acquiring AS DA is a sound concept. Most other ISOs and RTOs acquire AS DA, and the ISO's External Market Monitor ("EMM"), Potomac Economics, has long recommended that AS should be acquired in the DA market.[8]

Q 10: In principle, what impact would acquiring AS DA be expected to have on efficiency, energy security, and cost to consumers?

A: In principle, acquiring AS DA should improve efficiency and energy security, and lower cost to consumers. Identifying the resources that will provide AS in the DA timeframe reduces uncertainty about which resources will be called for which services, and gives the resources selected DA time to firm up fuel supplies as needed. Acquiring AS DA

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[8] See, for instance, Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets,* June 2014, p. 40 ("Recommendation 7: Consider introducing day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.")

supports development of a reliable next-day Operating Plan, and should reduce the frequency with which the ISO is dissatisfied with the results of the DA energy market and chooses to commit additional resources out of market.

Q 11: What is the usual approach ISOs and RTOs follow to acquire AS DA?

A: DA markets are forward markets. As a general matter, forward markets work well when they acquire the same products as needed in the delivery period, as the ISO has recognized.[9] Other ISOs and RTOs generally acquire DA the same AS products they will need in RT, and settle them against the corresponding RT prices,[10] as the ISO acknowledges.[11] If different products were acquired forward, this would create complexities and problems in evaluating performance, among other issues arising from the mismatch. Throughout this affidavit, I will refer to acquiring the same AS products DA as needed in RT the "conventional" approach to DA AS.

Q 12: Does the ESI proposal call for acquiring the same AS DA as needed in RT?

A: No. The ESI proposal calls for acquiring DA commitments to a single, new product, a financial energy call option ("Energy Option"). While the DA acquisition would acquire quantities and resources that correspond to the RT AS needs, including operational characteristics,[12] and could set AS-specific prices for the Energy Option,[13] the ESI

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[9] Chris Geissler and Steven Otto, ISO New England, *Energy Security Improvements (ESI):Forward Market Design Update*, NEPOOL Markets Committee meeting February 11-13, 2020, slide 8 ("Forward-market procurements work well when they settle against a transparent, spot price for the underlying service.")

[10] David Patton and Pallas LeeVanSchaick, Potomac Economics, Memorandum to ISO New England and NEPOOL Markets Committee *RE: Day-Ahead Market Power Mitigation*, January 21, 2020, p. 1 (noting that NYISO, MISO, CAISO and SPP all have DA AS that settle as forward contracts against RT prices for the same product).

[11] Hanhan Hammer and Chris Geissler, ISO New England, *Day-Ahead Reserves – Alternative Settlement Design and its Fuel Security Implications,* NEPOOL Markets Committee meeting December 10-11, 2019, p. 9.

[12] ESI Filing pp. 22-23.

[13] Whitepaper p. 53.

proposal does not acquire DA commitments for the AS products, and the DA Energy Option is not settled against a RT equivalent product. While this approach deviates from the guiding principle of forward market design noted above (forward products should match underlying products), it is a key feature of the ESI proposal.

Q 13: Please explain why ISO proposes to acquire DA the Energy Option, rather than the AS products.

A: The Energy Option entails a settlement that exposes sellers to the RT energy price that occurs *whether or not* they run in RT; the settlement can potentially amount to several thousand dollars per MWh, reflecting Reserve Constraint Penalty Factors ("RCPFs').

As explained in detail later in my affidavit, under circumstances where a market participant sells the Energy Option and believes its failure to run could cause significantly higher RT prices, the Energy Option can provide an added incentive to arrange for fuel. This is the key innovation of the ESI proposal that is intended to contribute to energy security.

Q 14: Now please identify the differences in the NEPOOL Alternative.

A: The NEPOOL Alternative maintains the fundamental scope and approach of the ISO's proposal, but includes three modifications, with the goal to strike a better balance between reliability benefits and costs to consumers:[14]

1. To set the RER quantity to zero in the non-winter months;
2. To remove a provision that allows reflecting load forecast uncertainty in the RER quantity; and

[14] NEPOOL Comments pp. 2-3.

3. To include a $10/MWh Strike Price Adder in the determination of the Energy Option strike price.

B. SUMMARY OF THE EVALUATION AND CONCLUSIONS

Q 15: Please summarize your evaluation and conclusion with regard to the ISO's ESI proposal.

A: I do not recommend support for the ESI proposal. The proposal is very likely to lead to excessive, unwarranted cost to consumers without commensurate energy security or other benefit. The incentive impact of the core market design element, the Energy Option, would be modest, and I doubt that the energy security impact of ESI would be sufficient to adequately address New England's energy security problem.

Q 16: Please explain the problems you see in the ESI proposal that lead to the inefficiency and excessive cost to consumers.

A: The following aspects of the ESI proposal lead to inefficiencies and risk to consumers of excessive and unwarranted costs, explained in detail in the remainder of my affidavit:

1. Imposing risk on sellers through the Energy Option can create added incentives, but it raises their risk and cost. This will lead to "risk premiums" added to their Energy Option offers, and some participants may choose to not offer to provide the Energy Option.[15] This will lead to higher Energy Option clearing prices, and, through co-optimization, potentially higher DA energy prices. This is an inefficiency that results from the Energy Option approach (a conventional approach to DA AS would not impose this risk and cost), and it raises the cost to consumers.

[15] Impact Assessment p. 31, pp. 126-128 discusses some of the costs resulting from the Energy Option that may be reflected in a risk premium.

2. The Energy Option approach also presents a unique and difficult challenge with regard to market power and mitigation. The ESI proposal leads to a very large demand for capacity DA, raising concerns about market power. The Energy Option can potentially impose a per-MWh settlement amounting to several thousand dollars, so determining an offer cap that is fair to sellers but also mitigates economic withholding is very problematic. Especially when the system is under some stress and prices are expected to be high, the mitigation of economic withholding is likely to afford substantial flexibility to raise offer prices. In addition, ISO proposes that offers to provide Energy Option would be voluntary, so physical withholding would, at best, be mitigated in an ex-post manner. As I will explain, I do not believe effective mitigation of the market power problem created by ESI is feasible.

3. The ESI proposal also includes various other market design compromises (such as settling the Energy Option at the System price, and not allowing AS-specific offers; see Section V below) that will lead to inefficiencies, and possibly gaming opportunities, that are also likely to raise the cost to consumers relative to a conventional approach to DA AS.

4. These costs and risks are exacerbated by the proposed very large total DA AS purchase quantities to be acquired subject to maximum prices based on RCPFs that greatly exceed the marginal reliability value to consumers.

These problems raise concerns about excess costs to consumers that can be described in two categories:

- ***"Slow Leak:"*** Relatively small but unwarranted excess prices and costs during times when energy security is not a concern, such as outside the winter period and during mild winter periods. While such impacts may be small, they are especially unwarranted if the occur when there is not an energy security concern, and there are many such hours in each year, so the cumulative impacts could be substantial.
- ***"Fast Leak:"*** Excessive cost during times of system stress, when risk and risk premiums would be higher, the system would be more vulnerable to exercise of market power, mitigation would be most problematic, and other inefficiencies may also have larger impacts. Such circumstances may occur rarely, but they could lead to very high prices and consumer costs.

Q 17: Please summarize your evaluation of ESI's core market design element, the DA Energy Option.

A: The Energy Option is a novel approach that has not been tried in any other region; nor can the ISO point to an analogous approach in a market for some other product or service. The Energy Option has a single distinguishing feature compared to the conventional approach to DA AS: exposing sellers to the potentially very high RT prices that could occur if they are called but do not generate electricity. While this unique feature can create some additional energy security incentives under some circumstances (as discussed in more detail below), I expect the incentive impact of this market design feature to be modest.

Q 18: Please summarize why you expect the added incentives resulting from the Energy Option market design element would be modest.

A: To the extent a market participant believes the RT price may be high, it already has an incentive to arrange fuel to be ready to earn the high RT price if it occurs. As explained further later in my affidavit, the Energy Option creates an *additional* incentive to arrange fuel only when a "Misaligned Incentives" problem is present, which only occurs when all of the following are true:

1. The market participant offers and clears to sell the Energy Option;
2. The market participant believes its output can have a substantial impact on RT prices: In particular, it believes that if it does not invest and cannot run, prices will be high enough in expectation to have made the investment profitable, but if it does invest and can run, its output will lead to lower prices, making the investment unprofitable; and
3. The market participant faces an indivisible or "lumpy" fuel decision; it cannot make a smaller investment to capture the anticipated high price, it faces an all-or-nothing decision that has the resulting large impact on expected prices.

Under these very specific circumstances, a market participant who sells the Energy Option sees an additional incentive to arrange fuel that may be as much as the expected difference in its Energy Option settlement depending upon whether it arranges fuel and is prepared to run if called or not. Smaller market participants who do not believe their output, or lack of output, appreciably affects RT prices, do not see an added incentive from the Energy Option. And market participants whose fuel options are not lumpy will tend to select profit-maximizing quantities, and may see little or no additional incentive from the Energy Option.

Due to the rather narrow circumstances under which any generator faces the Misaligned Incentives problem and the Energy Option can address it, I conclude that the impact of this market design element on incentives and energy security would be modest.

Q 19: If the impact of the Energy Option market design element on incentives and energy security would be modest, why is the potential impact of the ESI proposal on the cost to consumers substantial?

A: While the impact of the Energy Option market design element is modest, due to the various inefficiencies discussed above, ESI is likely to result in generally higher DA energy and AS prices and revenues, raising the cost to consumers.

Q 20: If ESI may substantially raise DA energy prices and revenues, even if primarily due to the inefficiencies in the market design you have noted, won't these extra revenues attract investments that contribute to fuel security?

A: The opportunity for higher revenues in the DA markets can attract investments to be able to capture the opportunities. However, strengthening energy security mainly through introducing inefficiencies into the DA market is not sound market design and does not provide value to consumers. Furthermore, it is likely that such incentives would not be very effective in influencing critical forward actions such as scheduling LNG cargoes or deciding to continue operation of large fuel secure resources, for three principal reasons:

1. First, it is doubtful how effective DA incentives may be for driving forward decisions. As noted above, ISO does not believe DA and RT incentives are sufficient to drive forward capacity decisions, thus it operates the FCM.

2. Second, the DA incentives would be highly uncertain and variable from year to year depending upon winter weather conditions. As suggested in the Impact Assessment, the additional revenues may be small in mild winters.[16] Highly uncertain DA revenue opportunities provide a weak forward incentive.

3. Finally, potential revenues that are primarily due to market design inefficiencies, rather than supply and demand fundamentals, would be discounted by market participants considering forward investments. Market participants would know that over time, the markets may shrink the impact of such inefficiencies, through arbitrage or other adjustments.

Q 21: Do you expect the ESI Proposal will adequately solve the New England energy security problem?

A: No. While ESI may lead to higher DA revenues and profits, primarily due to the inefficiencies inherent in the approach, I do not expect these excessive and unwarranted costs will change conduct in a manner that would address the New England energy security problem to the satisfaction of ISO and stakeholders.

Q 22: Does the ISO believe its ESI market design proposal creates effective incentives for longer forward actions (season or years forward) that contribute to energy security?

A: The ESI Filing and Whitepaper make such claims in vague terms, mainly relying on the increases in prices and costs that stem from the various ESI inefficiencies, not the specific incentives created by the Energy Option. The various examples in the Whitepaper all discuss short-term, post-DA incentives for resources that clear to sell the Energy Option.

[16] See, for instance, Impact Assessment p. 8, p. 53.

In a presentation in December 2019, the ISO did explicitly claim ESI incents fuel arrangements in advance of winter.[17] However, the incentive in the example given results from inefficiency, not market design. The example provided in support of the claim assumed the Energy Option clears at a price that reflects a substantial risk premium, and that some generators do not have such a risk premium, creating revenues without associated costs for these generators. As I will explain, higher revenues due to the risk premium caused by ESI reflect inefficiency, it is not a result of an efficient market design element.

Q 23: Setting aside for now the Energy Option, please comment on the three categories of AS.

A: As noted above, acquiring AS DA is in principle a sound approach, and is an approach followed by other ISOs and RTOs.

1. GCR: Acquiring generation contingency reserves DA is a sound approach, and the proposed quantities are based on the current quantities acquired for RT.
2. EIR: Acquiring energy imbalance reserves DA based on the ISO's DA load forecast supports energy security and a reliable DA operating plan by preventing substantial DA under-scheduling.

My affidavit focuses on RER, and I have not examined and evaluated every detail of the ESI proposal regarding GCR and EIR. However, I discuss below concerns about maximum prices and marginal reliability value that implicate GCR and EIR.

[17] Chris Geissler, ISO New England, *How the ESI design incents resources' fuel arrangements in advance of winter,* NEPOOL Markets Committee meeting December 11, 2019.

3. RER: The ISO proposal would also acquire Energy Options DA in amounts corresponding to possible replacement energy reserve needs. This additional quantity, on top of the GCR and EIR quantities, results in a very large total quantity of DA AS. Especially in the non-winter period, acquiring RER at prices that can substantially exceed the marginal reliability value of RER (as discussed further below), imposes cost on consumers that is not commensurate with reliability, energy security, or other benefits.

Q 24: Now please summarize your evaluation of the changes reflected in the NEPOOL Alternative.

A: Each of the three changes reflected in the NEPOOL Alternative improve the ESI proposal by helping to limit its cost without appreciably affecting the intended impacts:

1. ***Set the DA RER quantity to zero in the non-winter months:*** Outside the winter period, energy security is less of a concern and acquiring RER DA is not required by applicable reliability standards. Acquiring RER outside the winter period would lead to an excessive DA AS quantity and exacerbate the inefficiency of the ESI design. Acquiring RER outside the winter period would lead to costs to consumers that are unwarranted and without commensurate reliability or market benefits.

2. ***Remove the allowance for load forecast uncertainty in the DA RER quantity:*** Reflecting load forecast uncertainty in the RER quantity would further increase what is already a very large DA AS quantity, leading to additional ESI inefficiency and cost to consumers.

3. ***Include a $10/MWh Strike Price Adder:*** The Strike Price Adder, which is evaluated in detail in the last section of my affidavit, would reduce the cost and risk of the Energy Option for sellers, with a larger impact at lower price levels when energy security is less of a concern. This should moderate the cost to consumers of ESI without appreciably affecting its intended properties. The Strike Price Adder is an improvement to the ESI design.

Q 25: What is your conclusion with regard to the NEPOOL Alternative of the ESI proposal?

A: The NEPOOL Alternative improves on the ISO's ESI proposal in ways that would reduce the cost to consumers without appreciably affecting the intended impacts. However, I do not recommend support for the NEPOOL Alternative of the ESI proposal, which has the same fundamental structure and flaws as the ISO's variant. The energy security impact would likely be insufficient to adequately address New England's energy security problem, and the increased cost to consumers, while moderated by the three changes discussed above, would still be excessive, and not lead to commensurate benefits.

Q 26: The ISO commissioned the Impact Assessment to evaluate the potential impacts of the ESI proposal. First, please briefly describe the Impact Assessment.

A: The Impact Assessment attempts to simulate the New England DA and RT markets under three winter and two non-winter scenarios for both the Current Market Design ("CMD") and the ESI proposal. Then comparisons of results under ESI and CMD are interpreted as impacts of the ESI design.

Q 27: Please provide your general observations about the Impact Assessment.

A: Such modeling exercises can be useful in helping stakeholders understand the potential impacts of changes to market rules, and the Impact Assessment provides a large amount of discussion, analysis, and results. However, this was an unusually challenging simulation exercise, largely due to the complexity of the markets and of market participant decision-making under circumstances that challenge energy security. Ultimately, many simplifications to the model structure and dynamics were necessary.

As one example, to reasonably accurately model how the current market rules would operate in a cold snap, it is necessary to model how market participants with limited fuel would use opportunity cost bidding to manage their fuel on a day-to-day basis. This would seem to require modeling the energy price dynamics of a developing energy security situation, and the interconnections between weather forecasts, natural gas and electricity load forecasts, natural gas and oil prices and price forecasts (daily forward prices), peak and off-peak electricity forward prices, and inventories. The Impact Assessment necessarily represented these dynamics and the related decision-making in a highly simplified manner.

I lack confidence that the resulting simulations, while quite complex, represent real-world energy market dynamics with enough realism that the results meaningfully predict how market participants would act under CMD or under ESI. For this reason, I do not accept its conclusions about cost and efficiency impacts, and, accordingly, there are few references to the Impact Assessment in my affidavit.

C. Alternatives to the ESI Approach Exist

Q 28: You find that ESI would lead to inefficiency and excessive cost to consumers, and the benefits would not be commensurate; and you also conclude that ESI likely would not adequately address New England's energy security problem. Are there alternative approaches to DA AS and energy security that could be more effective?

A: Yes. A conventional approach to DA AS, based on the best practices of other RTOs, is an alternative that could potentially be more cost-effective. As noted above, the only advantage of the Energy Option approach is that it may provide some resources a modest additional incentive for energy security under some circumstances. However, the ISO proposes to further explore a seasonal forward market element, and the ISO, stakeholders, and Commission may ultimately decide that ESI does not adequately address the New England energy security problem, and a forward element is needed. A conventional approach to DA AS, combined with a seasonal or longer forward construct to provide incentives for energy secure resources and arrangements, is an alternative that potentially could be more effective and lower cost.

Q 29: Please elaborate on how a conventional approach to DA AS would work and how it would be different from ESI.

A: A conventional approach to DA AS based on the best practices of other RTOs, as long recommended by EMM, would acquire the same AS DA as ISO requires in RT. The DA AS would be settled against the corresponding RT market prices for the same AS. These designs also typically entail penalties for non-performance, analogous to the PfP penalties for capacity resources.

This approach to DA AS would not have the intended incentive property of the Energy Option, which I have found to be modest in any case. Thus, it would likely be paired with a forward market design element. This approach to DA AS would not have some of the drawbacks of the Energy Option approach; in particular:

1. A conventional approach does not result in substantial risk premiums raising DA AS and energy prices, as would occur under ESI.
2. Under a conventional approach the AS can be zonal, with zonal prices. This is not feasible under the Energy Option approach, as discussed later in my affidavit.
3. Under a conventional approach resources would have an opportunity to reflect in their offers any costs or limits specific to certain AS, also not allowed under ESI.

Q 30: What are the main design questions for a forward market design element?

A: The ISO's current thinking was outlined in a presentation in February 2020.[18] At that time ISO had in mind a seasonal forward construct (rather than years ahead), that would transact the same DA AS as introduced under ESI, and be settled against DA AS clearing prices. However, some key questions remained open, such as: whether the forward procurement would be voluntary or there would be a mandatory quantity, and details of the product definition, to name just a few key questions.

[18] *Energy Security Improvements (ESI): Forward Market Design Update,* MEPOOL Markets Committee meeting February 11-13, 2020.

IV. EVALUATION OF THE CORE ESI DESIGN ELEMENT: THE ENERGY OPTION

Q 31: What topics will this section of your affidavit address?

A: This section summarizes the ISO's problem statement that underlies the ESI proposal, and then describes and evaluates the ISO's core market design element, the Energy Option. This section explains my conclusion that while ESI inefficiencies may substantially raise DA energy and AS prices and costs, the impact of the core ESI market design – element – the Energy Option – will be modest, and overall ESI likely will not adequately address the New England energy security problem.

A. THE ISO'S ESI PROBLEM STATEMENT

Q 32: In your summary you grouped energy security concerns into short-term (actions during a cold snap) and longer-term (actions a season or longer forward). Which group is of greater concern?

A: I believe the longer-term incentives and actions are the greater concern. If resource owners, especially those relying upon natural gas, LNG, and/or fuel oil, haven't made adequate arrangements in advance of winter or a cold snap, the region could be at risk should an extended cold snap occur. The key problem is that we want resource owners to make investments before knowing what kind of winter it will be, investments that bolster energy security but that are likely to be unprofitable in most winters.

In the short term, as situations develop that challenge fuel security arrangements, resource owners have substantial incentives and flexibility to manage scarce inventories efficiently under the current market rules. Incentives are provided by RT shortage pricing with quite high RCPFs, and also Pay for Performance ("PfP") rules that impose large penalties for failure to perform when supplies are most needed. The ISO's opportunity cost bidding rules[19] allow owners to adjust their energy market bids to conserve scarce fuel for future periods when it may be more needed and valuable. Daily forward prices for energy and natural gas reflect the market's assessment of how serious a tight energy situation might become and how long it is likely to last, which information informs owners' choices as they manage scarce fuel.

Q 33: Please summarize the ISO's energy security problem statement.

A: The ISO's problem statement is presented in section 2 of the Whitepaper, and comprises what the Whitepaper describes as three interrelated problems:

1. **Misaligned Incentives:** market participants may have inefficiently low incentives to invest in energy supply arrangements that are cost-effective from society's standpoint.

2. **Operational Uncertainties:** There could be insufficient energy available to the power system as a result of, for example, an unexpected supply loss during a cold snap.

3. **Insufficient Day-Ahead Scheduling:** The ISO's DA market often clears less energy than will be needed in RT.

Q 34: Please briefly comment on these three interrelated problems and how the ESI proposal addresses them.

A: The first problem, Misaligned Incentives (hereafter "MI Problem"), is the core problem that is addressed by the core element of the ESI proposal, the Energy Option. I will discuss this in detail in this section.

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[19] ISO New England Energy Market Opportunity Cost (EMOC) Project, last updated January 31, 2020, available at https://www.iso-ne.com/participate/support/customer-readiness-outlook/emoc-project.

The second problem, Operational Uncertainties, is a common problem not just in power markets, but in many other markets. Acquiring AS DA, whether as proposed under ESI or through a more conventional approach, helps to address this problem.

The third problem, insufficient day-ahead scheduling, results from market participants' choices to buy and sell energy through the DA and RT markets. The ESI proposal addresses this by acquiring EIR DA.

Accordingly, my affidavit focuses on the first problem element, what ISO calls Misaligned Incentives.

Q 35: Please describe the Misaligned Incentives problem.

A: The MI Problem manifests when a market participant faces an energy-related investment that is not profitable for the participant, but would be cost-effective from society's standpoint (that is, the investment would be economically efficient and increase the combined welfare of consumers and producers):[20]

> "The value that society places on the generator's energy supply (e.g., fuel) arrangements is based on the high price society avoids as a result of the investment. However, the value the generator places on the same arrangement is based on the lower price that it receives in the energy market with the investment. This divergence between the social and private benefit of the investment represents a significant misaligned incentives problem."

[20] Whitepaper p. 3.

Q 36: Please describe an example of the MI Problem.

A: The Whitepaper provides a simplified "Example 1" wherein a generator faces a decision whether to invest $40 in fuel to be able to run the next day.[21] Under a Low Demand scenario the participant won't be called to run, and the investment would be wasted. However, under a High Demand scenario, the RT price will be $120 if the participant invests and can run, but will spike to $400 if the participant chooses not to invest and cannot run. Under this example, it is economically efficient from society's standpoint for the investment to happen (it increases economic efficiency), but the participant (who would earn the $120, not the $400) does not find the investment profitable and, presumably, would not choose to invest. Thus, under the example, the participant's private incentives are not aligned with society's interest that the investment occur.

Q 37: Please explain the circumstances under which the MI Problem manifests.

A: The Whitepaper describes three "root causes" of the MI Problem (p. 24): uncertainty about whether the resource will be called to run, an irrevocable investment that must be made beforehand, and "materiality" – some impact of the investment choice on RT prices and perhaps reliability. However, it is important to emphasize that the presence of the MI problem with respect to any specific investment rests upon three key circumstances:

1. **The investment is profitable at the prices that would occur if it is <u>not</u> made.** This is what is meant by the investment being in society's interest. If the investment is not profitable even at the higher prices that could occur if it is not made, the investment is not economically efficient and not in society's interest.

[21] Whitepaper p. 13, Example 1.

Note that consumers and ISO would like resource owners to make investments that bolster energy security even if they would only be profitable in a rare very cold winter, and might not be profitable in expectation over the long run. The ESI proposal is not attempting to incent such investments; the ISO has not proposed a higher reliability standard that takes into account energy security. This contrasts to FCM, which is designed to incent capacity investments beyond what the DA and RT market revenues would support.

2. **The investment is <u>not</u> profitable at the prices that would occur if it is made.** This is the core of the MI Problem – situations where the investment won't occur because it would impact prices enough to make it unprofitable. Note that this implies the resource owner believes its decision has a substantial impact on prices. Smaller market participants likely do not believe their decisions appreciably affect prices. In addition, this view also seems to presume other market participants won't act to take advantage of the attractive prices.

3. **The investment is "lumpy."** Note that the view that prices will be attractive if the investment is not made, but will be too low if it is made, presumes that the decision has to be made in a quantity that has a substantial impact on price; that is, the participant's investment is "lumpy." If instead a small portion of the investment can be made, it would capture the expected high price or close to it, and be profitable. If the participant could choose how much to invest, the participant would attempt to balance marginal benefit and market cost to maximize profits, and would likely invest

some fraction of the maximum potential investment; the MI problem either would not exist, or would be much less significant.

Q 38: In recent years some market participants have not filled their oil tanks before the winter; and the lack of stored oil could lead to price spikes and reliability challenges in a cold winter. Is this an example of the MI Problem?

A: No. These decisions are not lumpy – market participants can fill their tanks to the levels they believe maximize expected profits. In choosing not to make any further oil purchases before the winter, market participants are taking into account the potential for the price spikes that society faces, and concluding that incremental purchases are not worthwhile, given the risks. There is no MI Problem without a lumpy investment that can substantially affect prices.

Q 39: But if market participants did incur costs to store somewhat more oil, this would benefit consumers, by mitigating price spikes under the worst scenarios. Doesn't this show that there is a misalignment of incentives between market participants and consumers?

A: There is always a "misalignment" of <u>interests</u> to some extent between sellers and buyers in just about any market – sellers want to only provide the profitable amounts and prefer higher prices, while consumers benefit from additional, even excess, supply, which drives prices lower. The ISO's MI Problem exists when sellers provide less than this economically optimal quantity because incremental supply comes in lumpy packages, and the next lump would push supply beyond the optimal amount and drive prices below the optimal and profitable level.

Q 40: Can you provide some real-world examples of incremental supply decisions that are lumpy?

A: Whether to continue to operate or retire Mystic Power Plant Units 8&9, and the associated Everett Marine Terminal, is an example of a lumpy decision. A major pipeline expansion could also be an example. However, most of the decisions that affect energy security are small and/or can be made in increments, and are not lumpy.

A decision to invest in an incremental LNG cargo, which typically could be 3 Bcf of natural gas, could be considered a rather lumpy decision. However, a terminal operator or gas marketer considering scheduling an additional cargo might offer contracts or rights to portions of the LNG cargo to multiple customers (power plants, gas marketers, local gas distribution companies, and industrial customers, to name some candidates). The various potential customers, in considering whether and how much to contract under such an offer, would be considering relatively small quantities, which are not lumpy and likely not considered to affect prices very much. However, if enough customers sign up, the cargo could become profitable. Thus, the relevant decisions are not lumpy and there is no MI Problem in this example.

Q 41: Please summarize your discussion of the MI Problem.

A: The MI Problem is only present when a market participant considers an investment that is quite lumpy, and believes it would be profitable at the prices that would occur if it isn't made, but would not be profitable if the investment is made. I believe this circumstance is relatively rare. I believe more commonly, market participants face choices that are not lumpy and not expected to significantly affect prices, but that market participants do not expect to be sufficiently profitable, especially considering the uncertainty about weather and prices.

B. THE PROPOSED ENERGY OPTION

Q 42: Now please explain how the ESI proposal addresses the MI problem.

A: The proposed Energy Option is specifically designed to address the MI Problem. It does so by exposing market participants that can affect prices, and that choose to sell the option, to the price consequences of their failure to acquire fuel and be able to run.

Returning to the Whitepaper's Example 1, discussed above: Recall that the price spikes to $400 under the High Demand scenario if the participant fails to acquire fuel and cannot run. While society suffers the $400 price, the participant is unaffected by it. However, if the participant can be enticed to sell the Energy Option, the participant is then exposed to a settlement based on the RT price (the $400). This makes the participant care about this potential consequence of its decision.

The Whitepaper revisits this example[22] and adds the Energy Option, showing that if the Energy Option price is at least $30, the participant would sell the option, and it would then also find it profitable to spend the $40 to acquire fuel and be prepared to run if called. As a result, society would no longer be exposed to the $400 price spike under the High Demand scenario, a more efficient overall result under the assumptions of the example.

Q 43: If the market outcome in the Whitepaper's Example 1 Revisited is more efficient with the Energy Option, does this mean the cost to consumers is lower?

A: No. In the Whitepaper's example, the cost to consumers goes up.[23] The result is still more efficient, because the profit to the seller rises by more than the increase in the cost

[22] Whitepaper p. 81, Example 1, Revisited.
[23] Whitepaper p. 95.

to consumers. However, over the long run, a market design that achieves more efficient outcomes is likely to be lower cost to consumers, as sellers should compete away excess profits.

Q 44: Does the ISO believe the Energy Option only creates incentives to acquire fuel once a resource clears to sell it, or can it create incentives for decisions that must be made before the DA market?

A: The incentives created by the Energy Option are primarily for decisions that can be made after the DA market runs, when resources learn whether they have cleared to provide the option. All of the examples in the Whitepaper pertain to such post-DA market decisions, and the examples of "up-front" costs are all post-DA actions.[24]

However, the Whitepaper also seems to suggest the problem and solution may be applicable to decisions with longer lead times, at least in the examples given:[25]

> "Last, a note on timing: When we say 'arrange fuel in advance' in this example, we mean however far in advance of the operating day as is necessary (a day, a week, a month, or a season). Though such timing issues matter in practice, in this simplified example, how far in advance is not material."

Q 45: Please comment on whether the Energy Option creates incentives for actions that must be taken before the DA market.

A: I disagree that how far in advance a decision must be made is not material. Returning to Example 1 Revisited discussed above, we saw that the resource would need an Energy Option price of at least $30 to make it worthwhile to sell the option, and if (and only if) it

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[24] Whitepaper p. 15 (referring to an intraday-notice gas contract, arrangement for accelerated oil inventory replenishment, or charging for a storage resource).
[25] Whitepaper p. 15.

sold the option would it be worthwhile to acquire fuel. Thus, it offers $30 to provide the Energy Option, and if it clears, it makes the fuel investment.

But if the resource must make the fuel decision before the DA market, it may be highly uncertain whether its offer to sell the energy option would clear for $30. And the further in advance an investment must be made, the more uncertainty there would be about market conditions and Energy Option clearing prices.

Recall that the presence of the MI problem, and the associated impact of the energy option, hinge on a participant facing a lumpy decision that it expects will have a substantial impact on RT prices. In a longer forward time frame, there is much more chance that other market participants also face various choices that could influence future RT prices. Any one participant should have stronger doubts that its choices in a forward time frame will influence future prices. In addition, in a more forward time frame, more alternatives are available, so the "lumpy" characteristic is also less likely to be applicable. While some forward decisions are may be large, they likely would affect the ability to run in many hours and days, with flexibility to shift the resource to times when it is needed.

For these reasons, the impact of the Energy Option would be much weaker on decisions that must be made before the DA market runs and participants learn whether they are selling the option or not.

Q 46: Does the Impact Assessment shed any light on the relative impact of the Energy Option on decisions that can be made after the DA market is run, and on forward decisions?

A: No. The Impact Assessment does not model fuel-related decisions that occur after the DA market is run and are contingent on selling the Energy Option.[26] Accordingly, the Impact Assessment arguably does not model the impact of the Energy Option on incentives, only the impact of a general increase in energy and AS prices and revenues resulting from the ESI design and its inefficiencies.

C. ANTICIPATED COMPONENTS OF ENERGY OPTION OFFER PRICES

Q 47: How does the ISO expect market participants will prepare their offers to sell the Energy Option?

A: The Whitepaper is silent on this key question. The question was addressed in some presentations last summer,[27] but there is no discussion of it in the Whitepaper. The Impact Assessment discusses option offers for purposes of explaining the assumptions used in the modeling.[28]

Q 48: How do you expect market participants would determine the prices for their Energy Option offers?

A: I expect offers would include the following components.

1. **Expected Settlement.** This is the primary component of the offer price. Recall that when the RT price ("RTP") rises above the energy option strike price ("K"), the seller of the option must pay RTP - K. In most hours when the system is not under stress and likelihood of RT prices rising much above K is low, this component would be

[26] Impact Assessment pp. 60-61.

[27] See, for instance, Andrew Gillespie, ISO New England, *Discussion of a market-based solution to improve energy security in the region*, NEPOOL Markets Committee meeting June 10-12, 2019, pp. 38-44.

[28] Impact Assessment pp. 23-32.

very low; but when the system is under stress and participants fear the RT price could spike, this component could be very high.

2. **Unrecovered Fuel Cost.** A possible additional component for some participants under some circumstances is some additional cost that must be incurred to be able to run, for instance to acquire fuel. Returning to the example in the Whitepaper, the market participant must spend $40 to acquire fuel, but without the energy option, does not find this profitable (in the example, the expected loss is $30[29]). The energy option price would have to also cover this expected loss (called "Unrecovered Fuel Cost", because it is the fuel cost that is not recovered, in expectation, from running in RT), in addition to covering the expected settlement, to make selling the option at least break-even in expectation.

3. **Opportunity Cost.** Generators that are limited in the total amount of energy they can produce over the coming hours and days (perhaps due to low fuel inventories, or environmental restrictions) may reflect the opportunity cost of generating in profitable future periods in their offer prices.

4. **Risk Premium.** Another likely component is a risk premium. The Whitepaper is silent on any risk premium component to energy option offers, but it was discussed in the stakeholder process, and is a key assumption in the Impact Assessment.[30] Participants selling the Energy Option are exposed to settlements based on RT prices that can rise to thousands of dollars. For many participants, especially when the

[29] Whitepaper p. 16.
[30] Impact Assessment pp. 28-32.

system is under some stress, this may be considered a significant risk. As a result, they may include a risk premium in their offers to sell the energy option, as discussed further below.

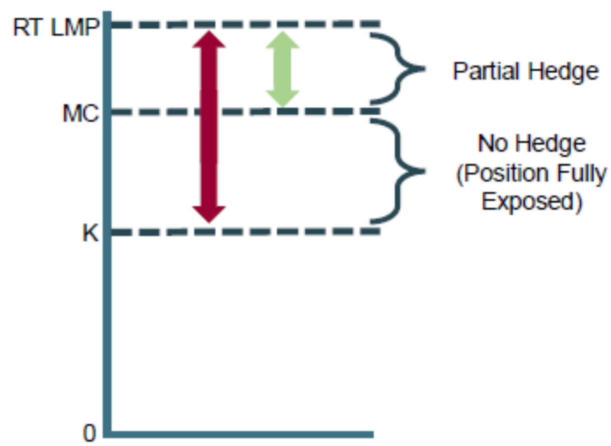
5. **Economic Withholding.** Finally, some market participants may find it profitable to further raise their Energy Option offer prices above the level that reflects expected settlement, unrecovered fuel cost (if any), opportunity cost, and a risk premium. This might be the case if they expect that offering at a higher price could contribute to a higher Energy Option clearing price, and potentially higher DA energy prices due to co-optimization, that would be earned by affiliated generation.

Q 49: Please further discuss the potential risk premium component to Energy Option offers.

A: When the RT price rises above the strike price, a seller of the option pays the settlement, RTP-K. If the RTP rises above the participant's marginal cost ("MC"), the participant presumably is called and runs, and earns the RTP for its output. Its total net earnings for the energy option settlement and its output will be (RTP - MC) – (RTP – K) = K – MC (it also receives V, the option price).

If MC is close to K, the energy option and RT output hedge each-other. This is illustrated in Figure 9 from the Impact Assessment, reproduced below. More often, MC > K, so the participant is exposed to a net payment of MC – K. This is the amount of the settlement that is not hedged by running. In addition, there is also some risk of a problem that

Figure 9. Illustration of Physical Hedge Provided by Energy Inventory to DA Energy Option Risk



prevents operation, in which case the participant is exposed to the full option settlement, RTP-K. Thus, market participants can be expected to include in their Energy Option offers a risk premium to reflect the potential unhedged settlement amount (MC – K), and also the risk of failing to run and having to pay the entire option settlement (RTP-K).

I also note that for highly reliable resources (for which the risk of failing to run is very low), when K is close to MC, the energy option is a very good hedge of real time earnings. Such a participant could even have a negative risk premium (that is, be willing to accept somewhat less than the expected settlement cost for the Energy Option hedge).

Q 50: What levels of risk premiums were assumed in the Impact Assessment?

A: The risk premiums are shown in Figures 7 and 8, and range up to about $15/MWh, with most resources assumed to use risk premiums in the $1/MWh to $7/MWh range.[31]

[31] Impact Assessment pp. 28-29.

Q 51: What are the consequences of risk premiums in the Energy Option offers?

A: The risk premiums can be expected to raise Energy Option clearing prices, and, through co-optimization, DA LMPs. And the market-clearing Energy Option offers are likely ones with relatively high risk premiums. So risk premiums would increase the cost of ESI to consumers. Because the risk premiums result from the Energy Option approach, this increased cost is an efficiency loss due to the ESI program.

Q 52: Please explain why the impact of risk premiums is an efficiency loss.

A: Risk premiums are, or are equivalent to, a cost for sellers to do business, just like fuel or O&M. A seller must be able to recover the risk premium, along with all other costs, to be willing to do business. However, this cost only exists due to the Energy Option and the settlement risk it creates; no such risk and risk premium exist in the current market design, nor would it exist in a conventional approach to DA ancillary services. In evaluating the efficiency impacts of ESI, this increased cost and the corresponding efficiency loss must be considered.

Q 53: The Whitepaper (p. 16) and Impact Assessment (pp. 68-69) suggest that arranging fuel in advance is like insurance. Is this accurate?

A: No; the analogy does not work and is misleading. Insurance is generally not a good investment from an expected value standpoint; the expected benefit generally does not exceed the expected cost of insurance premiums. Insurance companies must make money, so insurance premiums exceed expected payouts. The reason it is prudent to purchase insurance is because the bad outcome is more harmful than the dollars involved; the buyer is risk averse.

For the insurance analogy to be applicable, the ISO must argue that consumers are risk averse, or, similarly, there is an applicable reliability standard that calls for risk-averse decision-making.

Q 54: Please summarize your evaluation of the Energy Option.

A: I have explained that I expect the incentive impact of the Energy Option would be modest, due to the limited circumstances in which the MI Problem appears (a large lumpy decision with a major impact on prices, that would be profitable under the prices that occur if it is not made).

However, due to the various inefficiencies in the ESI design, ESI could substantially raise overall energy and AS prices and costs, and these higher revenues can attract some investments, as discussed earlier. Other concerns about the ESI design, inefficiencies it causes, and excess costs to consumers are discussed in the next section.

V. Detailed Discussion of Other Key Concerns

Q 55: What topics will this section of your affidavit address?

A: This section elaborates on some of the other key areas of concern about the ESI proposal identified in earlier sections of my affidavit. The first two subsections discuss the market power problem and why effective mitigation is likely infeasible. The third subsection discusses other inefficiencies in the ESI design that would lead to unwarranted costs to consumers. The final subsection explains my concern that the ISO proposes to acquire very large quantities of AS DA at prices that exceed the marginal reliability value of the AS, allowing the various inefficiencies to result in prices and costs well above competitive and efficient levels.

A. ESI IS UNUSUALLY SUSCEPTIBLE TO EXERCISE OF MARKET POWER

Q 56: What topics will this section of your testimony address?

A: This section first summarizes the discussion of market power and mitigation issues in the ESI stakeholder process. Then it discusses market power concerns raised by the ESI proposal, defining and analyzing the relevant market. The prospects for mitigating this market power are discussed in the next subsection.

Q 57: Please summarize the history of the discussions of market power and mitigation in the ESI stakeholder process.

A: The April 2019 ESI Discussion Paper first described the ISO's proposal to acquire large, administrative, and fixed quantities (no sloped demand curves) of AS in the DA market. The Discussion Paper also proposed that the DA product would actually be an Energy Option, with a potential settlement that could be several thousand dollars, and that offering to provide the Energy Option would be voluntary. The proposal immediately raised concerns with regard to the potential for market power and the feasibility of effectively mitigating potential economic and physical withholding of this novel product.

These concerns about the potential for market power and the feasibility of effective mitigation were repeatedly expressed by various stakeholders throughout the ESI stakeholder process. The first substantive response to these concerns by ISO, IMM, or EMM was in the form of a memo from IMM on July 3, 2019.[32] The IMM Memo recognized that the ESI proposal calls for a significant increase in the amount of capacity

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[32] *Market Power Mitigation and ISO-NE's Proposed Energy Security Improvements*, memorandum from Internal Market Monitoring, ISO New England, to NEPOOL Markets Committee, July 3, 2019 ("IMM Memo"), p. 1.

ISO would attempt to clear DA, and stated that exercise of market power had the potential to result in a significant and unjust increase in overall market cost:[33]

> … "the volume transacted in the DAM represents all capacity required to meet the load forecast, along with the other ESI reserve products. Price increases in the DAM resulting from the exercise of market power have the potential to result in a significant and unjust increase in overall market costs."

The IMM provided an additional memo in August 2019 focused on the ESI design that restated the market power mitigation concerns.[34]

NESCOE expressed its concerns about market power and mitigation in various Markets Committee meetings, in a presentation at the FERC technical conference on July 15, 2019, and at the August, 2019 NEPOOL summer meeting,[35] among other instances. In a presentation in September 2019, NESCOE stated that it "remains deeply concerned that consumers will be on the hook if the design fails to create competitive outcomes."[36] NESCOE further explained its concerns about market power and the feasibility of mitigation in a detailed 7-page memo to the EMM in October 2019.[37]

In a September 2019 memo, ISO presented a work plan that proposed preparing a market power assessment ("MPA") "to identify if there are anticipated market power conditions under the design," and tasked the EMM with developing a conceptual design approach

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[33] IMM Memo pp. 1-2.
[34] *Internal Market Monitor's Comments on ISO New England's Energy Security Proposal,* memorandum to NEPOOL Markets Committee, August 30, 2019.
[35] NESCOE, *New England Energy Security Solutions*, presentation at FERC Public Meeting July 15, 2019, slide 16; NESCOE, *ESI Preliminary Thoughts & Questions*, NEPOOL Markets Committee meeting August 13-15, 2019, slides 5, 7, 9, 12, 13.
[36] NESCOE, *ESI Possible Amendments,* NEPOOL Markets Committee meeting September 4, 2019, slide 5.
[37] *ISO-NE Energy Security Improvements: NESCOE's Mitigation Concerns,* Memo from NESCOE to Dr. David Patton, Potomac Economics, October 23, 2019 ("NESCOE Mitigation Concerns Memo").

for mitigation.[38] A later ISO memo further described the planned MPA,[39] and a January memo made it clear there would be no results from the MPA before third quarter 2020.[40] The ESI Filing states that the ISO "anticipates completing the MPA analysis and filing the results of that assessment, along with the appropriate mitigation proposal supported by those results, by the fourth quarter of 2020,"[41] while requesting Commission action on its filing by November 1, 2020.[42] The ESI Filing and supporting testimony and Whitepaper are otherwise silent with regard to the potential for market power and possible approaches to mitigation.

The EMM first commented on the ESI market design in a September 3, 2019 presentation; market power and mitigation were outside the scope of this first memo.[43] EMM first addressed market power and mitigation issues in writing in a presentation and memo in January 2020, discussed further below.[44]

To summarize, stakeholders have raised concerns about market power and the feasibility of mitigation since early in the process, and both IMM and EMM have expressed concerns about market power under ESI. However, the ISO remains agnostic, with any

[38] *Proposed Energy Security Improvements Work Plan,* memo from Vamsi Chadalavada to NEPOOL Participants and Markets Committees, September 30, 2019, p. 2.
[39] *Energy Security Improvements: Planned Scope of Mitigation-Related Work for Day-Ahead Ancillary Services*, memo from Mark Karl to NEPOOL Markets Committee, November 6, 2019.
[40] *Energy Security Improvements: Market Power Assessment Update*, memo from Matt White to NEPOOL Markets Committee, January 22, 2020.
[41] ESI Filing p. 70.
[42] ESI Filing p. 68.
[43] David Patton, PhD, *Comments on Fuel Security Proposals,* NEPOOL Markets Committee meeting September 3, 2019.
[44] David Patton and Pallas LeeVanSchaick, Potomac Economics, Memorandum to ISO New England and NEPOOL Markets Committee *RE: Day-Ahead Market Power Mitigation*, January 21, 2020 ("EMM Mitigation Memo"); David Patton, Potomac Economics, ISO New England External Market Monitor, *Market Power Mitigation for the Proposed Day-Ahead Ancillary Service Products*, NEPOOL Markets Committee meeting January 28, 2020.

position to be based on the MPA results later in this year, and there has not even been a scoping analysis of the potential for market power. As to mitigation approaches, detailed discussion only began in 2020 with the EMM Mitigation Memo, and the design remains at a conceptual level.

Q 58: Please explain how economists identify and evaluate market power concerns.

A: The standard approach usually begins with a specific product or supplier that may raise concern, and entails first defining the relevant market, which has a product and a geographic dimension. Around the initial product of concern it is necessary to identify all good substitutes, to be included in the relevant market. Failing to identify and include all good product and geographic substitutes in the relevant market would lead to incorrect results, because consumers can switch to these good substitutes to thwart an attempt to exercise market power.

Q 59: Please explain what you consider to be the relevant market of concern in this instance.

A: The relevant *geographic* market would include all suppliers able to sell into the ISO's wholesale markets. The identification of the relevant product market begins with the ESI Energy Option, or potentially the specific AS characteristics the ISO will seek to meet the anticipated GCR, EIR and RER quantities. EMM points out that the amount of available capacity that is eligible to provide each DA AS (GCR, EIR, RER) substantially exceeds the proposed demand for the service.[45] In addition, the total amount of capacity eligible to provide the DA AS collectively also substantially exceeds the total demand for all DA AS. Furthermore, through co-optimization of energy and ancillary services, the various

[45] EMM Mitigation Memo p. 12.

ancillary services and energy are substitutes under most circumstances. As EMM has explained, should a supplier attempt to physically or economically withhold the new DA AS, its capacity might instead be scheduled for DA energy, with other suppliers' capacity chosen to provide the AS.[46]

Accordingly, while there could be concerns at times about specific DA AS or total AS, I believe the focus should be on the total amount of capacity for energy and AS the ISO seeks to acquire DA. This relevant market – the total capacity ISO seeks to acquire for energy and AS DA – is well-defined, and raises the most concern. In the NESCOE Mitigation Concerns Memo, NESCOE identified this relevant product as the focus of concern.[47]

In the case of a forward market (such as a DA market), there can also be a temporal dimension to the relevant market identification. To the extent consumers can shift to other temporal purchase opportunities (such as the RT market) where conditions are competitive or there is effective mitigation, potential exercise of market power in a forward market could be thwarted. However, ISO intends to acquire a total amount of capacity DA based on its load forecast, which limits consumers' ability to shift purchases out of the DA market to the RT market.

[46] EMM Mitigation Memo p. 2.
[47] NESCOE Mitigation Concerns Memo p. 2.

Q 60: How has the EMM defined the relevant market?

A: The EMM Mitigation Memo does not explicitly identify a relevant product or market. It primarily discusses the AS and approaches to mitigation, while also noting co-optimization and substitution between energy and AS.

Q 61: Please summarize why you believe the relevant market defined as the total amount of capacity ISO will seek to acquire DA raises market power concerns.

A: ESI does not create any new or additional final, RT energy or AS demands; it moves AS procurement to the DA market. ISO proposes to procure the energy option in quantities based in the demands for individual AS (GCR, EIR, RER), from sellers eligible to provide these AS.

Under ESI, ISO will attempt to acquire a large total quantity of energy and AS in the DA market. In addition, ESI would create new incentives for all sellers of DA energy and AS to have fuel, and this could reduce participation by some suppliers, or increase the cost they will seek to recover through the markets.

Concerns about fuel security arise under circumstances such as an extended period of extreme cold, when demands for energy and AS are relatively high, gas pipelines are likely constrained, and some energy-limited resources may have depleted their fuel supplies. Under such circumstances, the total demand for DA energy and AS is high and approaches the total amount of capacity eligible to provide them, and it may be that the capacity of one or a few suppliers is needed for the total demand to be met. That is, one or a few sellers may be "pivotal" with respect to the total amount of DA energy and AS ISO seeks to acquire. When there are pivotal suppliers, some suppliers may be able to physically or economically withhold capacity and profitably raise DA energy and AS prices above competitive levels – that is, some sellers may have market power. Especially when it matters most – when the system is tight and energy security is a concern – such market power would appear to be quite likely.

Q 62: Has ISO or IMM or EMM presented any analysis to identify whether market power is likely under ESI?

A: No. No analysis of the potential for market power, such as a pivotal supplier analysis, has been made public. However, both IMM and EMM have suggested that there likely is market power and a need for mitigation.[48]

Q 63: You've noted that other ISOs and RTOs acquire AS DA. Are the market power concerns raised by ESI different from those present in other markets with DA AS?

A: Yes, I believe ESI raises different, and more problematic, market power issues.

The EMM Mitigation Memo discussed other RTOs' practices and compared the likely competitiveness of the DA AS under ESI to the other RTOs' DA AS markets.[49] The EMM Mitigation Memo identified five factors that would affect the susceptibility to market power under ESI relative to the DA AS designs of other RTOs (primarily focusing on NYISO and MISO). However, the EMM Mitigation Memo ultimately came to no conclusion, stating, "It is difficult to assess the overall impact of this confluence of factors on ISO-NE relative to other markets, since some of the factors increase competitiveness of the proposed markets in New England and others reduce it."

[48] IMM Memo p. 1; Dr. David Patton at January 28, 2020 NEPOOL Market Committee meeting (verbal).
[49] EMM Mitigation Memo, pp. 5-7.

Q 64: Do you agree that it is unclear whether ESI will be more or less susceptible to market power than other DA AS designs?

A: I disagree; the information provided in the EMM Mitigation Memo suggests that ESI will be more susceptible to market power. Of the EMM Mitigation Memo's five factors, three would enhance susceptibility to market power under ESI relative to the DA AS designs of other RTOs:

1. ESI would lead to a very large demand for DA AS (estimated as 25 percent of the overall demand for DA generating capacity), much larger than other RTOs acquire under their conventional approaches to DA AS (15 percent or less in the comparison markets). [50]

2. The ESI energy option has a "significantly higher marginal cost" in the DA market than the DA AS products acquired by other RTOs.

3. The supply of natural gas and other fuels is more limited in New England than in the other markets.

The other two factors tend to reduce susceptibility to market power:

4. The eligibility rules allow four-hour response for a portion of the RER quantity, expanding the pool of resources eligible to provide the service.

5. The FER constraint enhances cross-substitution between energy and reserves and increases the effectiveness of virtual transactions and imports for disciplining attempts to exercise market power.

[50] EMM Mitigation Memo p. 6 (stating that operating reserves as a share of the overall demand for capacity are 25% in New England, compared to 15% in New York and 3% in MISO).

However, factor 4 above can be understood as offsetting factor 1, but only to a small extent, especially since other RTOs do not acquire a product corresponding to RER. And the cross-substitution under factor 5 does not reduce market power with respect to the total amount of capacity sought DA. In other RTOs, loads can use virtuals to shift to RT to avoid DA market power, but that is prevented under ESI; the ISO will acquire EIR DA based on its load forecast.

Accordingly, contrary to the inconclusive statement in the EMM Mitigation Memo, the factors identified confirm my concern that ESI is relatively susceptible to market power, and in particular, is more susceptible than the conventional DA AS market designs of other RTOs.

B. EFFECTIVE MARKET POWER MITIGATION IS LIKELY INFEASIBLE

Q 65: Turning now to possible approaches to mitigation, what is the current thinking in this regard?

A: As noted above, the ISO tasked the EMM with developing a conceptual approach to mitigation, and the EMM's thinking was described in the EMM Mitigation Memo.[51] The EMM proposes what it describes as the "conduct-impact approach": An offer to provide the DA Energy Option would be mitigated ex ante if the price exceeds a reference offer price level plus a threshold, and if the offer also trips a threshold for its potential impact on prices. That is, offers that remain below a threshold level, or that would not have much impact on DA clearing prices, would not be mitigated.

[51] EMM Mitigation Memo pp. 7-12.

EMM recommended against imposing a must-offer requirement for the Energy Option, and instead recommended ex post sanctions to deter and punish physical withholding.

Q 66: How does EMM propose to establish reference price levels for the Energy Option?

A: The EMM Mitigation Memo states that the reference levels are intended to represent competitive offer levels, and should reflect a generator's short-run marginal cost, which includes the expected cost of satisfying the product's obligations.[52] The EMM Mitigation Memo identifies the same potential components of a competitive offer for the Energy Option as described in an earlier section of this affidavit: the expected cost of settlement, any unrecovered fuel cost, and potentially the opportunity cost of limited fuel.[53] The EMM Mitigation Memo also notes that suppliers should be permitted to reflect a risk premium, but proposes to include this in the conduct threshold rather than the reference price levels.

Q 67: How does EMM propose to establish the conduct thresholds?

A: The EMM Mitigation Memo states that the conduct thresholds should be set at levels that allow market participants the flexibility to express different price expectations and risk preferences, and suggests that a risk-based model will be needed to estimate risk premiums.[54] The memo does not suggest the magnitude of the conduct thresholds.

[52] EMM Mitigation Memo pp. 7-8.
[53] EMM Mitigation Memo pp. 8-10.
[54] EMM Mitigation Memo p. 9.

Q 68: Please comment on reference prices and conduct thresholds set in this manner.

A: There are a number of difficulties that would have to be faced to set reference levels and conduct thresholds for the proposed Energy Option. These difficulties were recognized by the IMM in its July, 2019, memo:[55]

> "The ESI products, as options, pose a different valuation problem as compared to energy and would require a different and potentially more complicated formulation and information set in order to calculate a reasonable asset-level proxy for a competitive offer."

The difficulties were also outlined in the NESCOE Mitigation Concerns Memo in October 2019, which stated the concern as follows:[56]

> "We are concerned that it may not be feasible to formulate a reference price formula for [the Energy Option] that is appropriate and effective for mitigating market power under all or nearly all market conditions and resource circumstances."

The main problem stems from the fact that a resource offering to provide the Energy Option is exposed to a financial settlement based on the actual RT energy price, however high it might rise; and under the ISO's administrative shortage pricing, the RT price can rise to several thousands of dollars per MWh. The EMM Mitigation Memo states,

> "Ignoring risk preferences, the cost of settling the call option is generally very similar for each reserve supplier in each hour because it primarily depends on the common strike price and the volatility of real-time LMPs at a common location."[57]

[55] IMM Memo p. 2.
[56] NESCOE Mitigation Concerns Memo p. 4.
[57] EMM Mitigation Memo p. 8, footnote omitted.

While in concept the expected settlement should be similar for all market participants, especially when the system faces a tightening energy or capacity situation, there may be substantial uncertainty about the likelihood and magnitude of RT price spikes, leading to a wide range of market participant valuations for the expected Energy Option settlement. Perceived risk and desired risk premiums will also vary widely under such circumstances. Thus, any particular estimate of the expected settlement is likely to be higher than many participants expect (allowing scope for economic withholding) while also being lower than some participants expect (over-mitigating offer prices, and potentially leading to physical withholding).

The other components of a competitive offer – a market participant's expected unrecovered fuel costs, and opportunity costs – are also based on the participant's current and forward price expectations. These components of a competitive offer can also vary widely, especially when the system is facing a tightening energy security situation.

Q 69: Does the EMM Mitigation Memo acknowledge these difficulties in setting reference levels for the Energy Option?

A: Yes. The EMM Mitigation Memo acknowledged the unique complexities in setting reference offer price levels for the energy option, and recognized that the methodology would have to accommodate resource-specific differences in the components,[58] as IMM had expressed earlier.[59] However, the EMM Mitigation Memo nevertheless expressed

[58] EMM Mitigation Memo pp. 7-9.
[59] IMM Memo p. 2.

confidence that the conduct-impact framework "can be effectively applied to the new day-ahead ancillary service products" proposed by the ISO.[60]

Q 70: Will reference price and conduct threshold levels established according to the EMM's conceptual approach be effective in preventing economic withholding?

A: No, I do not believe this approach can be effective. The reference price levels and conduct thresholds will likely afford market participants substantial flexibility to raise their offer prices when there is any stress on the system. Some market participants may legitimately use this flexibility to offer at very high prices based on their true understanding of market conditions and price expectations. However, other market participants might be motivated to use the opportunity to raise their offers above competitive levels, to exercise market power and raise DA market clearing prices, and there really won't be a way to distinguish between these different motives for the increased offer.

And to the extent the reference price levels and conduct thresholds are set too low in the eyes of some market participants, they may simply decline to offer to provide the Energy Option.

The EMM's conceptual approach to mitigation could work well most of the time when the system is not under stress. However, when the system comes under stress (or threat of stress), the situation may be very uncertain, due to uncertainties about the duration of a cold snap, natural gas availability, and the timing of fuel oil replenishment, to note just a few factors that can affect resource-specific costs, risk premiums, and expectations of

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[60] EMM Mitigation Memo p. 7.

near-term electric and natural gas prices. It could be very difficult to ascertain whether a market participant's very high Energy Option offer prices, or choice to not offer to provide the energy option for certain resources, was legitimate given the view of the market at the time, or instead amounted to economic withholding to exercise market power. Accordingly, it would seem likely that the reference price levels will be very generous, potentially allowing sellers to increase their offer prices to well above competitive levels.

Should instead the reference price levels be set at lower levels that could more effectively mitigate economic withholding, suppliers would simply exercise their right to not offer to provide the energy option at all.

Q 71: Are you aware of any examples of attempts to mitigate a product with the option characteristics of the Energy Option?

A: No. In particular, I am not aware of any attempt to mitigate a product that could impose such high settlements on a seller as a standard outcome of the product, even if the seller has fulfilled all of its obligations. Again, I don't believe it will prove feasible to effectively mitigate the Energy Option.

Q 72: Now please describe the EMM's approach to mitigating physical withholding.

A: The EMM Mitigation Memo recommends against imposing a must-offer requirement to mitigate physical withholding, noting "several undesirable consequences" of requiring suppliers to offer the Energy Option when it is not economic to do so.[61] The EMM Mitigation Memo states that allowing units to choose to not offer will have no material

[61] EMM Mitigation Memo pp. 11-12.

impact on market outcomes "under most conditions." Instead, EMM proposes that IMM would impose ex-post financial penalties when it found physical withholding. However, no details of how this would be done (for example, how IMM would determine that such sanctions were appropriate, or the magnitude of the sanctions) were suggested.

I anticipate that such ex post mitigation of physical withholding would be complex and controversial, and also ultimately ineffective at deterring or punishing physical withholding.

Q 73: Please summarize your conclusions about the prospect for effective mitigation of the relevant product you have identified.

A: I do not believe it will prove feasible to effectively mitigate physical and economic withholding of the Energy Option. This will allow exercise of market power that will raise the prices of the total amount of DA energy and AS ISO seeks to acquire under its ESI proposal.

Q 74: Are there other ways to help limit the potential impact of exercise of market power?

A: Yes. One approach to limiting the impact would be to acquire the Energy Option employing a sloped demand curve reflecting the marginal reliability value. This would set the maximum willingness to pay for each quantity based on its value, consistent with the consumers' interest. Stakeholders suggested this approach very early in the stakeholder process. The ISO acknowledged the potential value of the approach in July 2019, but put off developing sloped demand curves to the distant future:[62]

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[62] Ben Ewing and Andrew Gillespie, ISO New England, *Discussion of a market-based solution to improve energy security in the region*, NEPOOL Markets Committee meeting July 8-10, 2019, slide 68.

> "However, given the complexity associated with deriving sound, sloped demand curves for each new ancillary service at this point in time, that would be better addressed as part of the ISO's efforts in 2020+, subject to FERC approval of the core ESI design filing in October."

As noted above, no progress has been made in evaluating the marginal reliability value of DA AS, or toward the analysis that would be needed to derive sound, sloped demand curves.

Q 75: What approach to market power mitigation do you recommend?

A: I do not have an alternative proposal. I doubt that an effective approach can be devised, and expect that the mitigation ultimately will be very loose and ineffective, contributing to the inefficiency and excessive cost that I expect would result from the ESI proposal. If ESI will be approved in some form, other measures to help limit the impact on consumers should be pursued, such as the three provisions unique to the NEPOOL Alternative of the ESI proposal.

C. Other ESI Market Design Compromises That Will Cause Inefficiency

Q 76: What topics does this subsection address?

A: This section raises additional concerns about inefficiencies in the ESI design that will contribute to unwarranted costs to consumers. ESI is a novel and untried market design approach, and beyond the specific issues I identify in this and earlier sections, there is risk of unanticipated and unintended outcomes due to some combination of market design shortcomings and participant conduct to exploit those flaws.

Q 77: Please explain the aspects of the ESI design that are novel and untried.

A: The core of the ESI proposal is the DA Energy Option, which exposes sellers of the option to a settlement based on actual RT prices, however high the RT price may rise. The ISO could not identify any other ISO, RTO, or utility that has tried such an approach, or any analogous market feature in another industry. I am not aware of any other party suggesting that something like this energy option has been used elsewhere, in the electric power or another industry.

Q 78: How is the fact that this aspect of the ESI design is novel and untried important?

A: The Energy Option is expected to carry a very low price during nearly all hours of the year, because RT prices and the settlement would remain low, and there should be a large amount of capacity that can sell the option. However, there is risk in offering the option, and resources are expected to add a risk premium to their offer prices; ISO will apparently also allow resources to decline to offer to provide the Energy Option. Because this approach has never been tried, we can't know how many resources will and won't participate, what level of risk premium will be added, or how resources will evaluate the expected option settlement, among other uncertainties.

Q 79: Are there other ESI market design features that raise concerns about inefficiencies?

A: Yes. There are some features of the ESI market design which are inefficient, resulting from compromises or simplifications necessary to resolve various design trade-offs. These features would lead to inefficiency that raises consumer costs to an unknown extent. To identify just two such features that lead to inefficiencies:

1. ISO proposes to base the Energy Option settlement on the System Hub RT price, which is different from the RT price each resource actually earns at its node.[63]

2. ISO proposes that the Energy Option will be the sole DA AS product; resources would not have an opportunity to reflect in their offers any costs or limits specific to certain AS.

Q 80: Please explain why settling the Energy Option based on the System RT price leads to inefficiencies.

A: With this settlement rule, each resource providing the Energy Option faces additional "basis risk." For resources in generation-rich export constrained zones, the option settlement would be at a price greater than the price the resource earns if it runs in RT, creating additional risk.

Perhaps more important, for a resource in an import constrained zone where RT prices may be greater than the System price, the Energy Option fails to expose the resource to the full potential consequences of its failure to run in RT. Under these circumstances, the Energy Option fails to fully address the MI problem.

This feature will also tend to distort market participants' incentives to submit competitive offers for energy and AS, due to the mismatch between the locational DA and RT energy prices they face, and the Energy Option settlement based on prices from a different location that could be very different.

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[63] Whitepaper p. 70.

Q 81: Why did the ISO propose settling the Energy Option at the System price, rather than at each resource's nodal price?

A: That approach might seem to resolve these issues; however, it would raise other problems and complexities. If the Energy Option is settled at each resource's nodal price, the option's cost and value become location- and resource-specific, and this would somehow have to be considered as energy and option offers are co-optimized in the DA market solution.

ISO claims that the DA AS are, "foundationally", system-wide products. However, this is a design choice, and a compromise. When transmission constraints occur, AS in one zone may not be deliverable to address a contingency in a constrained zone.

Note that under a conventional two-settlement approach to DA AS, AS needs and prices can be established on a zonal basis, as is the practice at some RTOs. This is another advantage of a conventional approach to AS compared to ESI.

Q 82: Please explain why it matters that resources would not have an opportunity to reflect in their offers any costs or limits specific to certain AS.

A: In the stakeholder process, market participants noted that their resources may have operational characteristics and related costs that are different for the different AS. In co-optimizing energy and AS DA, the ISO would not have this information, and yet would be selecting a mix of resources that it believes satisfies the AS requirements and their operational requirements. Lacking relevant information, the result of the co-optimization might not be the optimal mix of resources, and could be inefficient. And a resource would have to prepare its offer DA without knowing for which AS ISO might select it.

Again, under a conventional approach to DA AS, market participants could be permitted to make AS-specific offers that reflect the specific quantities they can provide and the costs they would incur for each AS.

Q 83: Have you estimated the potential impacts of these and other design compromises on efficiency and cost to consumers?

A: No. Given the uncertainty about how market participants would prepare their Energy Option offers under this new and untested market design, it would be very difficult to predict how these and other design compromises will impact efficiency and cost. However, new, complex market designs can lead to unintended consequences that generally raise the cost to consumers. For this additional reason, modifications to the ISO's proposal designed to reduce the risk to consumers – such as those reflected in the NEPOOL Alternative – warrant consideration.

Q 84: Did the Impact Assessment evaluate the efficiency of the ESI proposal?

A: No, it provides an incomplete analysis. While the Impact Assessment makes various claims about efficiency, it ignores risk premiums, a key assumption of the analysis. The Impact Assessment defines "production costs" excluding risk premiums:[64]

> "While our evaluation of production costs appropriately captures the social cost of the physical resources used by generators to meet customer loads, it may not encompass all social costs and benefits. For example, production costs may not capture certain financial costs and changes in utility, although capturing these effects would be very challenging and beyond the scope of our analysis.[52]
>
> [note 52]: ESI may cause a range of effects to financial cost and underlying utility of consumers. The procurement of DA energy options, for example, may

[64] Impact Assessment p. 67.

> impose financial costs if it causes changes to market participant's financial structures to account for changes in financial risk. However, accounting for these costs would be extremely complex, particularly given the potential for ESI to have spillover effects on other market operations."

The Impact Assessment results are quite sensitive to the assumed risk premiums; in a sensitivity analysis that increased the risk premiums by 25%, total payments increased by $42 million, $29 million and $13 million for the Frequent, Extended and Infrequent Case, respectively.[65]

If risk premiums are not considered costs of production, then offers that include them are not competitive offers, and the cost increases that result from them are, in essence, due to exercise of market power.

D. DA AS Maximum Prices Exceed Marginal Reliability Value

Q 85: What topics will this section of your affidavit address?

A: This section addresses the key question of the marginal reliability value ("MRV") for consumers of different quantities of DA AS, and how MRV compares to the maximum prices ISO proposes to pay for the DA AS, capped by RCPFs.

Q 86: Why is the marginal reliability value of the DA AS important?

A: As explained in my Summary and discussed further below, in concept, the maximum the ISO should be willing to pay for different quantities of DA AS should be based on and consistent with marginal reliability value. This concept is well established for shortage

[65] Impact Assessment p. 89.

pricing rules, as the ESI Filing recognizes.[66] The ISO also applied this concept to develop the demand curve for its FCM capacity construct.

Q 87: Were questions about the MRV of the DA AS raised in the ESI stakeholder process?

A: Yes. NESCOE and other stakeholders raised questions about the MRV of the proposed DA AS quantities repeatedly in the stakeholder process.[67] The ISO did not address the issue, while also not contesting that it was relevant.

Q 88: Please summarize the quantities of DA AS the ISO proposes to acquire.

A: The AS quantities would vary day to day based on system conditions. Based on historical data, the Whitepaper shows the median quantity of GCR close to 2,400 MW, and the median quantity of GCR and RER together close to 3,600 MW.[68] The EIR quantity would reflect the amount of under-scheduling that otherwise would occur in the DA market. As the EMM has noted, these DA AS quantities are large compared to the practices of other RTOs with DA AS.[69]

Q 89: Has the ISO evaluated the MRV of these DA quantities, to establish or justify the maximum prices it will stand ready to pay?

A: No. The ISO simply proposes to use the existing Reserve Constraint Penalty Factors, or RCPFs, applicable to its RT market as the maximum prices for each category of DA AS.[70]

[66] See, for instance, ESI Filing p. 11 footnote 30, citing a Commission order "increasing the Reserve Constraint Penalty Factors to more accurately reflect the marginal value of reserves during times of scarcity."
[67] See, for example, email from Jeff Bentz to Andrew Gillespie and Matthew White, June 18, 2019 ("We also ask that you provide some discussion of how the proposed approach approximates marginal reliability value (if it does), or to explain why not, if it doesn't.").
[68] Whitepaper p. 169 Table 7-5.
[69] EMM Mitigation Memo p. 6.
[70] ESI Filing pp. 50-51.

The ISO also proposes new RCPFs applicable to the four-hour and 90-minute portions of the RER requirement, of $100/MWh and $250/MWh, respectively.[71]

Q 90: How did the ISO rationalize using the same RCPFs DA as used in the RT market?

A: The explanation was as follows:[72]

> The rationale for using the same Reserve Penalty Constraint Factors in the day-ahead and the real-time market for the analogous Demand Quantities (née requirements) is so that the day-ahead markets will send the same reserve shortage price signal if that shortage is anticipated by (that is, occurs in clearing) the day-ahead market. By doing so, the day-ahead market will signal the full value of actions that market participants may be able to take to help avoid, or reduce the magnitude of, a potential real-time reserve shortage that signals heightened reliability risks."

Q 91: Is it appropriate to use the same maximum prices for a forward market, such as the DA market, as are considered appropriate to the RT market?

A: Obviously not. Shortage prices are supposed to reflect the marginal reliability value of incremental RT reserves at different levels of shortage; this well-established principle is discussed further later in this section of my testimony. In a forward context – be it years, months, weeks, or even just a day forward – the same bid-in supply and demand balance reflects very different risk and marginal reliability value as in RT. Should the bid-in supply and demand in a forward market appear to signal scarcity, there is time for loads, suppliers and ISO to take additional actions before the delivery period to improve the supply-demand balance – time, and actions, that are not available in the RT market context for which shortage price rules were developed. Thus, a bid-in supply-demand

[71] Whitepaper pp. 178-179.
[72] Whitepaper p. 180.

situation in a forward context represents lower true risk of an actual delivery period shortage than the same bid-in supply-demand balance in the RT market.

In addition, the appropriate value of lost load ("VOLL") for use in evaluating MRV DA is somewhat lower than the value applicable to RT, due to the forward price signal and additional time. When a forward market signals some degree of scarcity, this gives the ISO and utilities time to warn consumers and suppliers of a possible tight situation that could lead to firm load drop, and this gives consumers and suppliers time to prepare. Advance warning lowers the impact on consumers of curtailment (VOLL), and such advance warning is not necessarily available when shortages occur in the RT market.

Q 92: Please summarize the maximum prices the ISO proposes to stand willing to pay for the DA AS quantities.

A: The maximum prices for each type of reserve based on RCPFs reflect a quality hierarchy among the AS and the cascading price relationships that flow from it.[73] Because the faster responding reserves are substitutes for the slower responding reserves (10-minute spinning reserve can serve as 30-minute reserve, etc.), but the reverse is not true, there is a natural hierarchy to the GCR and RER reserves and their prices. Recent typical quantities of each reserve type, and the corresponding maximum prices based on RCPFs, are summarized in Table 1.

[73] Whitepaper pp. 164-167.

Table 1: Typical Quantities and Proposed Maximum Prices for DA AS

Reserve Type	Applicable RCPF ($/MW)	Maximum Price [1] ($/MW)	Median Quantity 2019 (MW)	Incremental Quantity (MW)
10-min spinning	$50	$2,900	586	586
Total 10 minute	$1,500	$2,850	1,584	998
Total 30 minute	$1,000	$1,350	2,370	786
Total 90 minute	$250	$350	2,992	622
Total 240 minute	$100	$100	3,604	612
Energy imbalance [2]	101%	$2,929	n.a.	n.a.

[1] Maximum prices reflect the cascading price relationships between AS.
[2] Energy imbalance maximum prices is 101% of maximum reserve price.
Sources: Proposed tariff sections III.2.6.2 and III.2.6.7, Whitepaper Table 7.5.

Q 93: What has ISO proposed as the maximum price for EIR?

A: The maximum price for the Forecast Energy Requirement Demand Quantity, which reflects EIR, is set at 101% of the sum of the RCPFs applicable to the other DA AS, or $2,929/MWh.[74] The rationale for this is that EIR is essentially energy, so it should be purchased at higher priority than the other DA AS that represent reserves.[75]

Q 94: Does ISO claim that offering prices this high for these AS quantities in the DA timeframe is somehow in the customers' interest?

A: No, the ISO makes no such claim. The ISO has not performed any analysis in this regard or made any claims about the value to customers of incremental DA AS purchase quantities. The rationale for using the RCPFs is based on observed maximum redispatch

[74] Whitepaper p. 144 footnote 117.
[75] Whitepaper p. 144.

costs, with a presumption that ISO should stand ready to pay whatever it costs to acquire these quantities DA: [76]

> "The RCPFs are "cost caps" intended to enable the system to meet the requirements. They reflect the maximum redispatch cost to meet those requirements and set the clearing prices in a shortage."

Q 95: What is the ISO's rationale for the new $100/MWh and $250/MWh RCPFs applicable to RER?

A: The rationale for the $100/MWh value was also based on observed maximum redispatch costs, and was explained as follows:[77]

> "To determine an appropriate Reserve Constraint Penalty Factor for this purpose, we used the model developed for the Impact Assessment to evaluate the maximum "re-dispatch" costs that would be incurred to enable that model of the co-optimized day ahead market to satisfy the full Day-Ahead Total Four-Hour Reserve Demand Quantity, for various scenarios evaluated in the Impact Assessment. The concept is that it would be undesirable to set a Reserve Constraint Penalty Factor too low, as that would cause frequent "artificial" shortages of replacement energy reserve. Such an outcome would undermine the reliability objectives and goals of procuring replacement energy reserve to meet the next-day operating plan's requirements."

The $250/MWh value was also justified based on observed redispatch costs.[78]

Q 96: In principle, how should maximum prices for incremental AS quantities, reflecting marginal reliability value, be determined?

A: The applicable principles have been established over many years in the context of RTO administrative shortage pricing rules using operating reserve demand curves ("ORDCs").

[76] ESI Filing p. 50.
[77] Whitepaper p. 178.
[78] Whitepaper pp. 179-180.

The ORDC concept, and the principles for its design, have been explained many times by the ORDC concept's founder and eminent proponent, Prof. William Hogan of Harvard University.[79]

In principle, at the very lowest reserve levels, ORDC prices should approach the value of service to consumers (VOLL), because when reserves are depleted the system operator will have to call for firm load curtailment. The slope of the ORDC down from its highest price level is based upon the probability, at each reserve level Q, that conditions would lead to firm load curtailment, if only that quantity of reserves is available (Loss of Load Probability, or LOLP(Q)).[80] Thus, the ORDC prices, in principle, reflect VOLL x LOLP(Q) at each point along the curve. An ORDC might begin its slope down from VOLL not at zero reserves, but at a higher "Security Minimum" level of reserves (the point below which the system operator would call for involuntary load curtailment, because this level of reserves is required to manage the grid safely and minimize the risk of potentially catastrophic and widespread transmission system failures).[81]

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[79] See, for instance Hogan, William H., *On An "Energy Only" Electricity Market Design for Resource Adequacy,* September 23, 2005, available at https://sites.hks.harvard.edu/fs/whogan/Hogan_Energy_Only_092305.pdf; Hogan, William H., *Scarcity Pricing and Locational Operating Reserve Demand Curves,* FERC Technical Conference on Unit Commitment Software, Docket No. AD10-12, June 2, 2010; Hogan, William H. and Pope, Susan L., *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, May 9, 2017 ("Hogan/Pope ERCOT Report") available at https://hepg.hks.harvard.edu/files/hepg/files/hogan_pope_ercot_050917.pdf, Hogan, William H. and Pope, Susan L., *PJM Reserve Markets: Operating Reserve Demand Curve Enhancements*, Attachment C to PJM Interconnection, LLC's Enhanced Price Formation in Reserve Markets filing in Docket Nos. EL19-58-000 and ER19-1486-000, March 29, 2019 ("Hogan/Pope PJM Report").

[80] See, for instance, Hogan/Pope PJM Report p. 15.

[81] Hogan/Pope PJM Report p. 34; see also Hogan/Pope ERCOT Report, p. 15.

Q 97: What evidence is available regarding the MRV of the proposed DA AS quantities in the New England market?

A: I am not aware of any analysis of the LOLP associated with different levels of DA AS procurement and shortage conditions, or the corresponding MRV.

Q 98: If the ISO wished to evaluate the MRV of the proposed DA AS, what would be the approach?

A: The approach would be to build a probabilistic simulation of the short-term (DA and RT) operation of the system, with a focus on stressed conditions. Such a model would simulate scenarios that result in lost load to estimate LOLP(Q), and could evaluate the MRV of the proposed AS quantities on that basis.

Q 99: Please elaborate on how such a model would work.

A: Such a model would need to be highly probabilistic, to capture the uncertainties and risks that can combine and lead to a need for AS quantities to maintain reliability and prevent loss of load. The goal would be to identify and quantify the most extreme scenarios that lead to the maximum AS need, and to roughly identify the likelihood of the scenarios that can lead to a need for firm load curtailment (LOLP(Q)). The worst scenarios that lead to maximum AS need would result from combinations of unlikely events, so the joint probabilities would be quite low.

Based on the simulated maximum AS demands and associated LOLP(Q), and on an estimate of VOLL, the MRV of different AS quantities could be estimated.

Q 100: Please elaborate on the probabilistic structure of such a model.

A: The model would have to represent very short-term uncertainties about load levels, the performance of all resources reflecting capacity and fuel availability, and the availability of additional resources beyond those scheduled (from unscheduled resources, customer demand response, neighboring regions) under the most extreme scenarios. The model would also have to realistically represent the amount of advance notice the ISO would likely have for some of the uncertainties, and the tools available to the ISO and to market participants to mitigate risk and take advantage of opportunities that are signaled in the DA market.

Q 101: A goal of the ESI proposal is to satisfy all reliability needs through market mechanisms in the DA market, thereby avoiding a need for out-of-market commitments after the DA market. Is it appropriate to model post-DA, out of-market actions in evaluating MRV of the DA AS?

A: Yes, the possibility of such actions should be modeled, otherwise the resulting MRV would not be correct. We know that the ISO would take such additional actions at times, even with ESI in place, if conditions warranted, and this would reduce the risk of load drop associated with various low DA reserve levels. To reflect that such out-of-market actions are undesirable from a market perspective, a relatively high "cost" could be assigned to such actions for the purpose of the MRV analysis, although this value should be far below VOLL.

Q 102: Please identify a few examples of such probabilistic models.

A: One recent example of a model with this structure was prepared by PJM staff for analysis related to recent changes to its ORDC.[82] The ISO also prepared such a model for a different time frame, to determine the shape of its sloped FCM capacity demand curve.

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[82] PJM Interconnection, LLC, *Enhanced Price Formation in Reserve Markets,* Docket Nos. EL19-58-000 and ER19-1486-000, March 29, 2019, Attachment F, Affidavit of Dr. Patricio Rocha Garrido.

Q 103: What would you expect such a model would show with regard to the MRV of the ISO's requested DA AS quantities?

A: I expect that such a model would show that the MRV of the full quantity of AS the ISO seeks to acquire DA is extremely low.

I also expect that such a model would show that the MRV of the full quantity of GCR and EIR the ISO seeks to acquire in the non-winter period is also extremely low, suggesting that the MRV of any quantity of RER in the non-winter period is even lower.

Q 104: Please explain why you expect the MRV of the full AS quantity is extremely low.

A: The EIR quantity can be ignored in such calculations, as it roughly corresponds to energy that must in any case be acquired, so the focus is on GCR and RER. First, a need for the full GCR quantity occurs very rarely, as it must entail multiple large contingencies.[83] When contingency reserves are used and do fall low, there is time to replace the reserves, and resources will often be available whether or not RER has been acquired. Finally, there are additional actions available to the ISO before it is necessary to curtail firm load, as described in the ISO's Operating Procedure No. 4.[84] Firm load curtailment would result only when all of these other actions fail to address the situation.

Q 105: Please provide a rough illustrative calculation of MRV of the requested DA AS quantity.

A: In very rough and illustrative terms: if a need to activate close to the full GCR quantity is a one-in-thousand event, and the RER resources and various other available resources and actions have a ninety-nine percent chance of mitigating the reliability risk and

[83] See, for instance, Whitepaper p. 159 and Table 7-1. The GCR quantity is based on the largest contingency plus one-half of the second largest contingency.
[84] *ISO New England Operating Procedure No. 4, Action During A Capacity Deficiency*, Effective Date: May 7, 2019 ("OP-4"), pp. 4-6.

avoiding load drop at such times, the combined likelihood (LOLP) is on the order of 10^-5 (I believe this estimate is very high; the probability is likely considerably lower). Times a rough value for VOLL of $10,000/MWh (also high), this would suggest an MRV on the order of $0.10/MWH for the last MW of the total AS quantity, or three orders of magnitude lower than the proposed RCPF for RER ($100/MWh for the 4-hour product). The MRV rises, slowly, at lower AS levels.

Similarly, I expect that at the total GCR quantity, the calculation is similar (the second term, the 99%, is a bit higher), and suggests that the MRV of the last MW of the total GCR quantity is far below the requested maximum price of $1,350/MWh (Table 1 above).

Q 106: Please explain why you expect the MRV of the full GCR and EIR quantity in the non-winter period is extremely low.

A: The rough calculation would be similar, but the likelihood that there will be resources to replace GCR when called is much higher in the non-winter period when energy security is much less of a concern (gas pipelines are not constrained, timely oil replenishment is not a problem, etc.).

VI. EVALUATION OF THE NEPOOL-APPROVED ALTERNATIVE TO THE ESI PROPOSAL

Q 107: What topics will this section of your affidavit address?

A: This section evaluates the three changes to the ISO's ESI proposal that were approved by the NEPOOL Participants' Committee on April 2, 2020:

1. To set the RER quantity to zero in the non-winter months;

2. To remove a provision that allows reflecting load forecast uncertainty in the RER quantity; and
3. To include a $10/MWh Strike Price Adder in the determination of the Energy Option strike price.

Q 108: With these changes, would the NEPOOL Alternative to the ESI proposal result in an adequate and cost-effective solution to New England's energy security challenges?

A: No. The NEPOOL Alternative has the same fundamental structure and flaws as the ISO's variant. The NEPOOL Alternative improves on the ISO's ESI proposal in ways that would reduce the cost to consumers without appreciably sacrificing any of the intended impacts. However, while the cost to consumers would be moderated by the three changes discussed below, the benefits would still not be commensurate.

A. SET RER QUANTITY TO ZERO IN NON-WINTER MONTHS

Q 109: Please describe the provision regarding RER quantity.

A: The NEPOOL Alternative calls for setting the RER quantity to zero outside of the winter period of December through February.

Q 110: On what basis has the ISO opposed this provision?

A: The ISO argues that procuring RER DA is consistent with the objective of transparently pricing through markets the costs of operating a reliable power system.[85]

Q 111: What is NEPOOL's rationale for removing RER in the non-winter period?

A: NEPOOL and its supporting witnesses make a number of arguments, including the following:

[85] ESI Filing p. 41.

1. Acquiring RER is not required by the governing reliability standards.[86]
2. The energy security concerns at the center of this proceeding are winter concerns, and ISO has not demonstrated a need to acquire RER outside the winter period.[87]
3. There is no evidence that acquiring RER outside the winter period would improve efficiency or incentives.[88]
4. Acquiring RER outside of the winter period would impose costs without commensurate reliability or market benefit.[89]
5. The objective of transparent pricing does not justify the potential cost of acquiring RER outside the winter period.[90]

In this section of my affidavit I provide my analysis and conclusions with regard to this proposal, and will not repeat all of the facts and arguments presented by NEPOOL and its witnesses.

Q 112: Please summarize the Northeast Power Coordinating Council, Inc. ("NPCC") and North American Electric Reliability Corporation ("NERC") reliability standards pertaining to reserves and reserve restoration.

A: NPCC's Regional Reliability Reference Directory # 5, Reserve, Version 4 (January 16, 2020; "Directory 5") describes the requirements for ISO to plan for and deploy adequate reserves, including requirements to restore reserves after they are used to address a contingency.

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[86] NEPOOL Comments pp. 20-21, Griffiths Affidavit pp. 10-12.
[87] NEPOOL Comments pp. 19-20, Griffiths Affidavit p. 10, pp. 13-19.
[88] Griffiths Affidavit pp. 19-22.
[89] NEPOOL Comments pp. 21-23, Griffiths Affidavit pp. 23-28.
[90] Griffiths Affidavit pp. 28-30.

Directory 5 calls for ISO to "restore its ten-minute reserve as soon as possible and within the duration specified in the appropriate NERC standard." The applicable NERC standard is BAL-002-3.[91] NERC defines the Contingency Event Recovery Period as 15 minutes, and the Contingency Reserve Restoration Period as not more than 90 minutes.[92]

Q 113: Do these reliability requirements require ISO to arrange for RER DA?

A: No; ISO is compliant now. The purpose of RER is to restore operating reserves used to meet a contingency. However, while Directory 5 identifies minimum quantities for contingency reserves, it does not impose any requirement equivalent to RER. Furthermore, to the extent something like RER is needed in RT, there is no requirement that it be acquired DA.

Q 114: What impact would you expect acquiring RER in the non-winter period would have on efficiency?

A: Acquiring RER in the non-winter period would have a negative impact on efficiency. At best, the corresponding DA prices would remain near zero due to a large surplus of capacity that can provide the service. However, I do not expect this to occur; market participants will request materially higher prices in light of the risk, risk premiums and other inefficiencies of the ESI design, discussed earlier in my affidavit. These RER prices would reflect the inefficiencies of the ESI design, and would exceed the marginal reliability value of the reserves, as discussed in an earlier section of my affidavit. This would lead to costs without commensurate reliability or efficiency benefits.

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[91] NERC, BAL-002-3, *Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event*.
[92] NERC, *Glossary of Terms Used in NERC Reliability Standards*, Updated February 24, 2020.

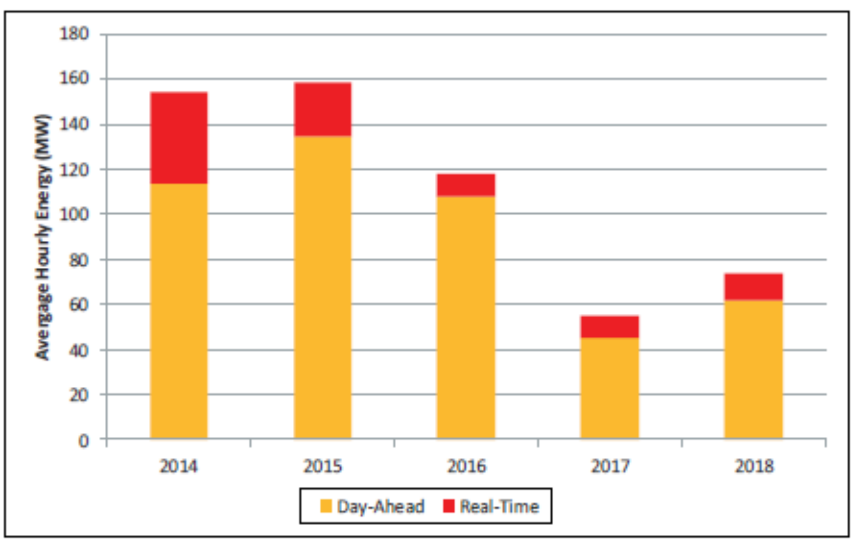
Q 115: Did the Impact Assessment evaluate the potential impact on efficiency of removing RER in the non-winter months?

A: No. The Impact Assessment states, "While we do not quantify these effects, we expect that ESI would create reliability benefits and reductions in production costs during non-winter months, as well as during winter months."[93] However, as explained in an earlier section of my affidavit, the Impact Assessment defines production costs excluding risk premiums, rendering it an incomplete metric.

Q 116: The ESI Filing states that ISO sometimes takes out-of-market, unpriced actions because its market design is "incomplete." First, please summarize the recent quantities of such out-of-market actions.

A: The average hourly energy from such reliability commitments are summarized in the IMM's annual markets reports. Figure 3-28 from the most recent such report is reproduced here,[94] and shows that such actions have averaged 60-70 MW per hour in recent years.

Figure 3-28: Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



[93] Impact Assessment p. 79.
[94] ISO New England Inc. Internal Market Monitor, *2018 Annual Markets Report,* May 23, 2019, p. 85.

Q 117: While these quantities are small, would the ESI proposal obviate the need for such actions?

A: No; the ISO will still choose to take such actions at times. Note that over 90% of the 2018 quantity (66.5 MW) was for Local Second Contingency Reliability Protection, primarily in the NEMA/Boston, SEMA, and RI zones.[95] Because the proposed DA AS would be acquired on a system-wide basis, it is not clear whether and to what extent ESI would reduce these actions that address local circumstances.

Q 118: Some stakeholders suggest that because ISO relies on the availability of resources in RT to restore operating reserves to have a reliable DA Operating Plan, but does not compensate any resources for this, some resources are providing a service without compensation. Is this accurate?

A: No. The ISO's DA Operating Plan is reliable based on DA commitments and expectations of load and supply circumstances in RT. ISO is not required to have DA commitments from all the resources it may choose to call in RT. In any case, resources are compensated if they are called to provide energy to restore reserves in RT, and they also receive capacity payments and potentially Pay for Performance bonuses, among other sources of revenue. Such resources are not asked to provide, nor do they provide, a DA "service."

[95] Id p. 85.

B. REMOVE PROVISION FOR LOAD FORECAST UNCERTAINTY

Q 119: Please describe what the NEPOOL Alternative includes regarding load forecast uncertainty.

A: The ISO's proposal includes a provision that would allow the ISO to increase the RER quantity to reflect potential load forecast error.[96] The NEPOOL Alternative eliminates this provision.

Q 120: Please summarize the ISO's rationale for including load forecast uncertainty in the proposed tariff language.

A: The ESI Filing suggests that reliability standards require accounting for demand patterns and the use of reserves for load forecast errors, so the ISO's proposal formalizes this in the market.[97]

Q 121: Has ISO proposed a methodology for quantifying load forecast error, or suggested what the quantity would be for this tariff provision?

A: No. However, in a presentation in February, 2020, ISO shared its current thinking on a methodology, and provided estimates of load forecast error using historical data.[98] This analysis suggested the quantity could be 360 MW, if the 95th percentile of the error distribution is chosen.

Q 122: Are there NPCC or NERC reliability standards or guidance pertaining to whether and how load forecast uncertainty should be reflected in AS quantities?

A: No, as the ISO acknowledges.[99] ISO only claims that reflecting load forecast error is "rooted" in reliability standards.

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[96] ESI Filing p. 38.
[97] ESI Filing p. 42.
[98] Andrew Gillespie, ISO New England, *Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion*, NEPOOL Markets Committee meeting February 11-13, 2020, slide 22.
[99] Id, slides 8-9.

Q 123: Please comment on the need to include load forecast uncertainty in the DA RER quantity.

A: There is no need to include this provision, which would increase the already excessive total DA AS quantity, leading to additional ESI inefficiency and cost to consumers.

C. INCLUDE A $10/MWH STRIKE PRICE ADDER

Q 124: Please describe the provision of the NEPOOL Alternative calling for a Strike Price Adder.

A: Under the NEPOOL Alternative, the strike price for the Energy Option is increased in all hours by a $10/MWh Strike Price Adder.[100] Everything else about the calculation of the Energy Option strike price and its settlement would be the same, but the resulting strike prices would be $10/MWh higher at all times.

Q 125: Please explain the purpose of the Strike Price Adder.

A: The purpose of the Strike Price Adder is to reduce the expected cost and risk of the Energy Option for sellers. That should, in turn, reduce sellers' offer prices to provide the Energy Option (which reflect the expected settlement, and possibly a risk premium), leading to lower Energy Option clearing prices. And that should lead to improved efficiency and reduced cost to consumers.

A rather modest Strike Price Adder, such as the $10/MWh included in the NEPOOL Alternative, should reduce the cost and risk of ESI to consumers somewhat, while not appreciably affecting the incentives created by the Energy Option.

[100] ESI Filing p. 47.

Q 126: Please briefly describe how ISO proposes to set the Energy Option strike prices.

A: The ISO proposes to set the hourly strike prices based on forecasts of the expected hourly Real-Time system hub prices prepared using a "publicly-available forecasting algorithm."[101] The strike prices will be calculated and posted before bids are due for the DA market.

Q 127: Will this approach result in strike prices that accurately predict RT prices?

A: The approach will likely produce strike prices that often differ significantly from the market's expectations of DA and RT prices. The data used in the forecasting algorithm will have been collected roughly two days before the operating day. The ISO's forecasting algorithm will necessarily be imperfect, as the ISO recognizes.[102] And the errors are likely to be larger when the system is under stress and prices are more volatile and uncertain.

Inaccuracy in setting the strike prices will result in considerable "noise" in the operation of the Energy Option, with many hours when the strike price has been set well above or well below the DA and RT prices expected by market participants.

Q 128: Please explain how the Strike Price Adder reduces the cost and risk of the Energy Option for sellers.

A: Increasing the strike price by a Strike Price Adder reduces the frequency of Energy Option strikes, which occur when the RT price rises above the strike price. The Strike Price Adder also reduces the magnitude of the Energy Option settlement when there is a strike, because the settlement is the difference between the RT price and the strike price.

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[101] Whitepaper p. 78.
[102] Whitepaper p. 76 ("Forward-looking forecasts of market outcomes are inherently imperfect…").

For example, consider an hour when the strike price without adder would be $40/MWh. With a $10/MWh Strike Price Adder the strike price is instead $50/MWh. If the RT price falls in the $40 - $50 range, there would be a strike and settlement under the ISO's proposal, but no strike or settlement under the NEPOOL Alternative with the Strike Price Adder. And if the RT price rises above $50/MWh, the settlement will be $10/MWh lower under the NEPOOL Alternative due the $10/MWh higher strike price.

Q 129: Please elaborate on why the Strike Price Adder should reduce the cost and risk of ESI for consumers.

A: As explained earlier in my affidavit, the main component of the offer prices to provide the Energy Option will be the expected settlement. The Strike Price Adder reduces the expected settlement, which should reduce Energy Option offer prices and clearing prices by a similar amount.

The Strike Price Adder, by reducing the magnitude and also the frequency of Energy Option strikes, should also reduce the perceived risk of the Energy Option for some sellers. This should reduce risk premiums and further contribute to lower Energy Option offer prices and clearing prices.

In addition, by reducing cost and risk, the Strike Price Adder could also encourage greater participation by resources that might otherwise choose to not offer to provide the Energy Option at times. This would also improve efficiency and have a moderating impact on Energy Option clearing prices and the cost of ESI to consumers.

The Strike Price Adder also helps to mitigate the impact of the noise resulting from the inaccuracy of the ISO's forecasting algorithm, and should mitigate the inefficiency this causes.

The Energy Option settlement payments flow through to consumers, so lower settlements will largely offset the savings from lower Energy Option clearing prices. However, overall, it should be expected that with the Strike Price Adder, the Energy Option would impose less cost and risk on potential sellers, and this should lead to overall more efficient outcomes, and lower cost for consumers.

Q 130: What is the ISO's rationale for opposing the Strike Price Adder?

A: The ISO believes the Strike Price Adder would at times reduce the incentives of some sellers of the Energy Option to procure fuel, which would undermine the efficacy of the Energy Option in addressing the MI Problem.[103]

Q 131: What is the EMM's position on the proposed $10/MWh Strike Price Adder?

A: EMM supports the proposed Strike Price Adder. In a memorandum in March 2020,[104] EMM evaluated a Strike Price Adder in the $10/MWh range, and ultimately concluded as follows:[105]

"Therefore, we support NESCOE's proposal to raise the strike price by $10 per MWh from the expected real-time price level. While it is impossible to estimate the optimal amount by which the strike price should be increased, there is ample information to suggest that:

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[103] ESI Filing p. 48.
[104] *RE: NESCOE Proposal to Raise the Strike Price of Energy Call Options*, Memorandum from David B. Patton and Pallas LeeVanSchaick, Potomac Economics, to ISO New England and NEPOOL Markets Committee, March 20, 2020.
[105] *Id,* p. 3

- This change would not undermine the market and reliability benefits of satisfying reserve adequacy needs within the market, but
- Would reduce the likelihood that the day-ahead ancillary services market would lead to excessive costs to consumers to during mild and moderate operating conditions.

Q 132: Have you performed analysis of the impact of the $10/MWh Strike Price Adder on the frequency of Energy Option strikes and settlements?

A: Yes. I evaluated the potential impact of the $10/MWh Strike Price Adder on the frequency of Energy Option settlements, using historical hourly data from the January 1, 2017 through May 31, 2019 period. For this analysis, I used the historical DA System Hub energy prices as proxies for the strike prices without an adder. The results are shown in Figures JFW-1 (for all hours) and JFW-2 (only Winter hours).

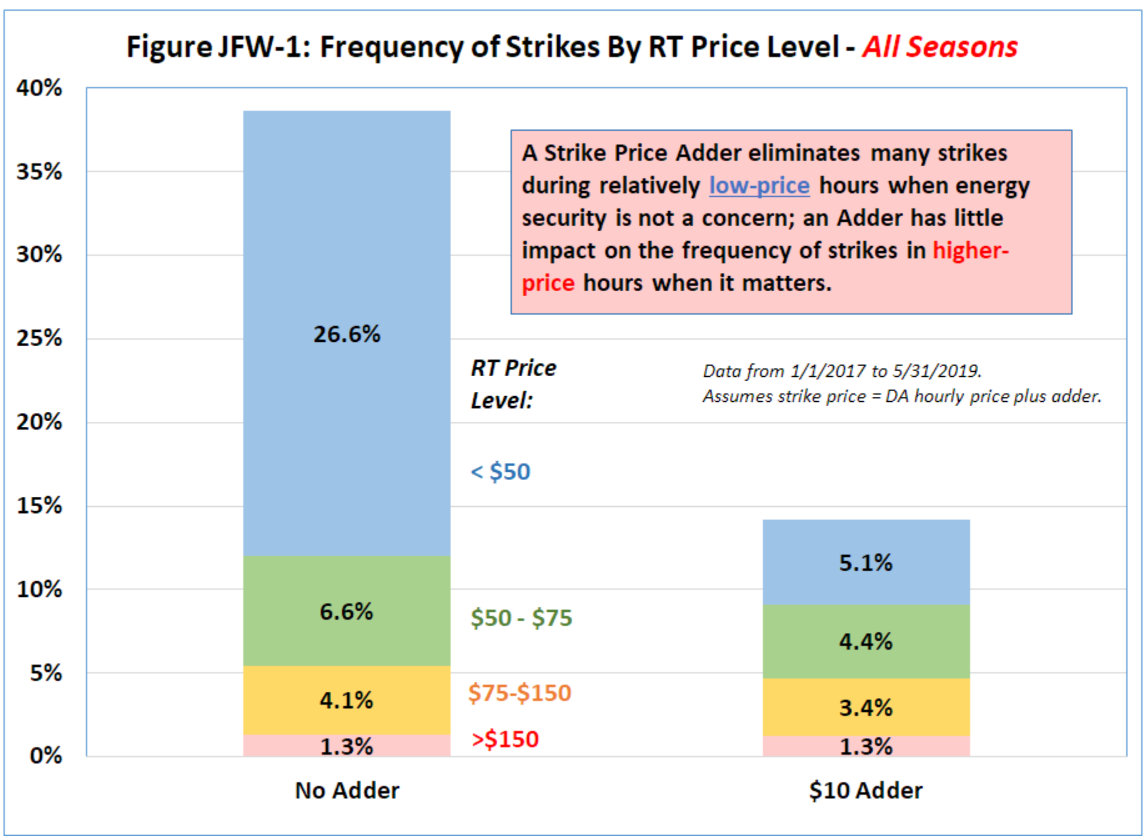
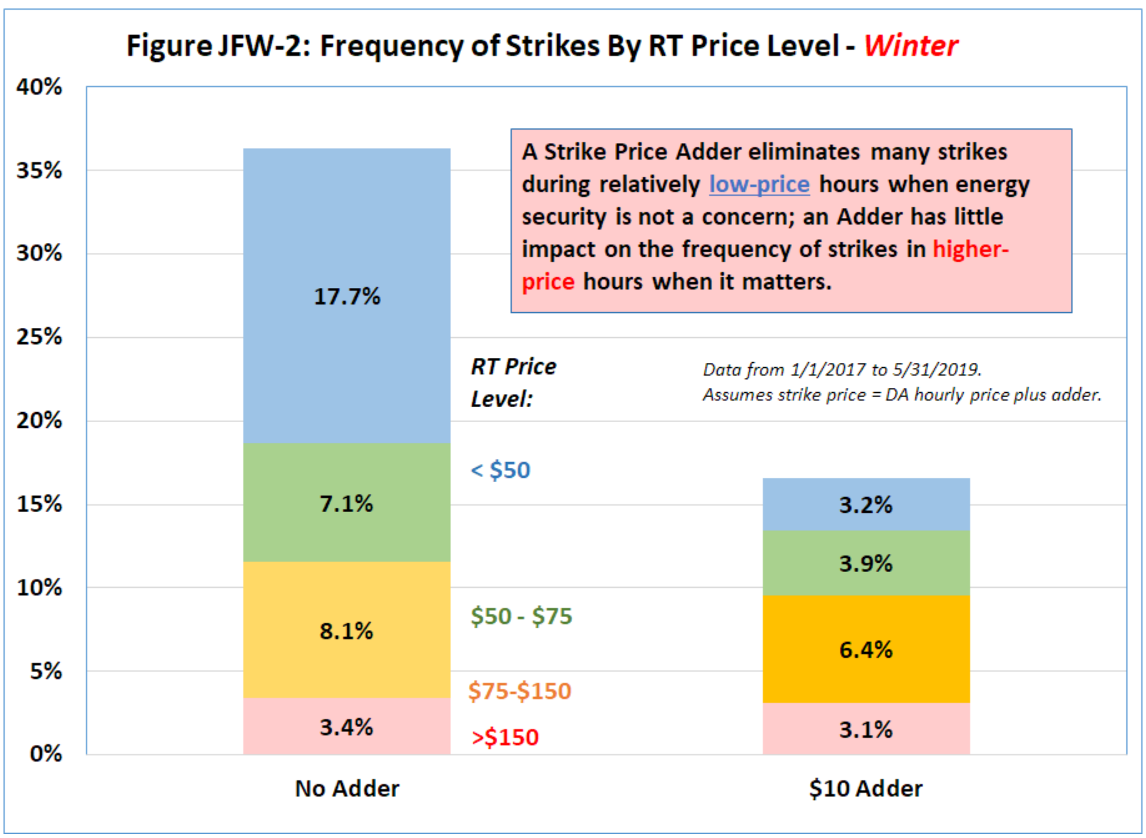


Figure JFW-1: Frequency of Strikes By RT Price Level - *All Seasons*

Figure JFW-1 shows the frequency of strikes for different RT price levels. The first column is the analysis with no Strike Price Adder. Overall, there are strikes in about 39% of the hours, including in 26.6% of the hours when prices are below $50/MWh. With the $10/MWh Strike Price Adder, the overall frequency of strikes declines to under 15%, and the frequency of strikes at prices below $50/MWH declines to just 5.1%. At the same time, the frequency of strikes at the highest price levels (over $150/MWh) is unchanged (to two decimal places) at 1.3%. The frequency of strikes in the $75-$150 range declines somewhat from 4.1% with no adder to 3.4% with the $10 adder.

This analysis suggests that the proposed $10/MWh Strike Price Adder would eliminate many strikes when RT prices are low (and energy security is not a concern), and would

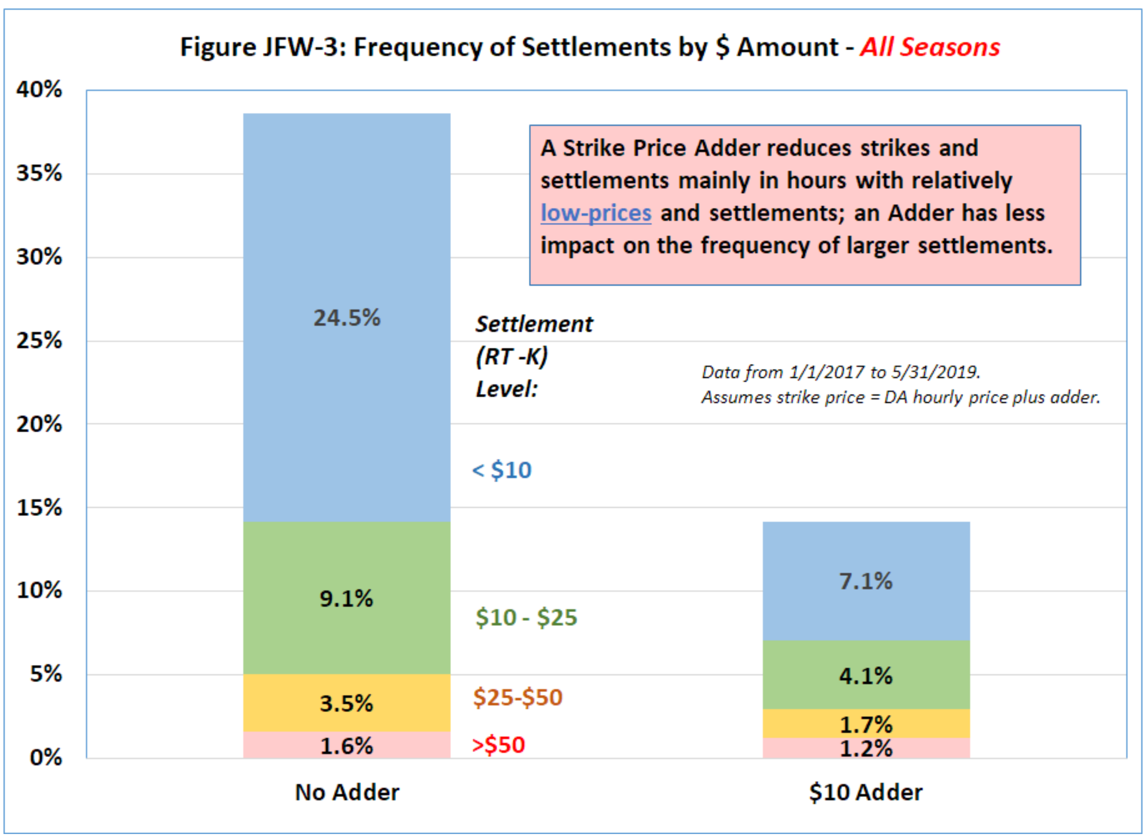


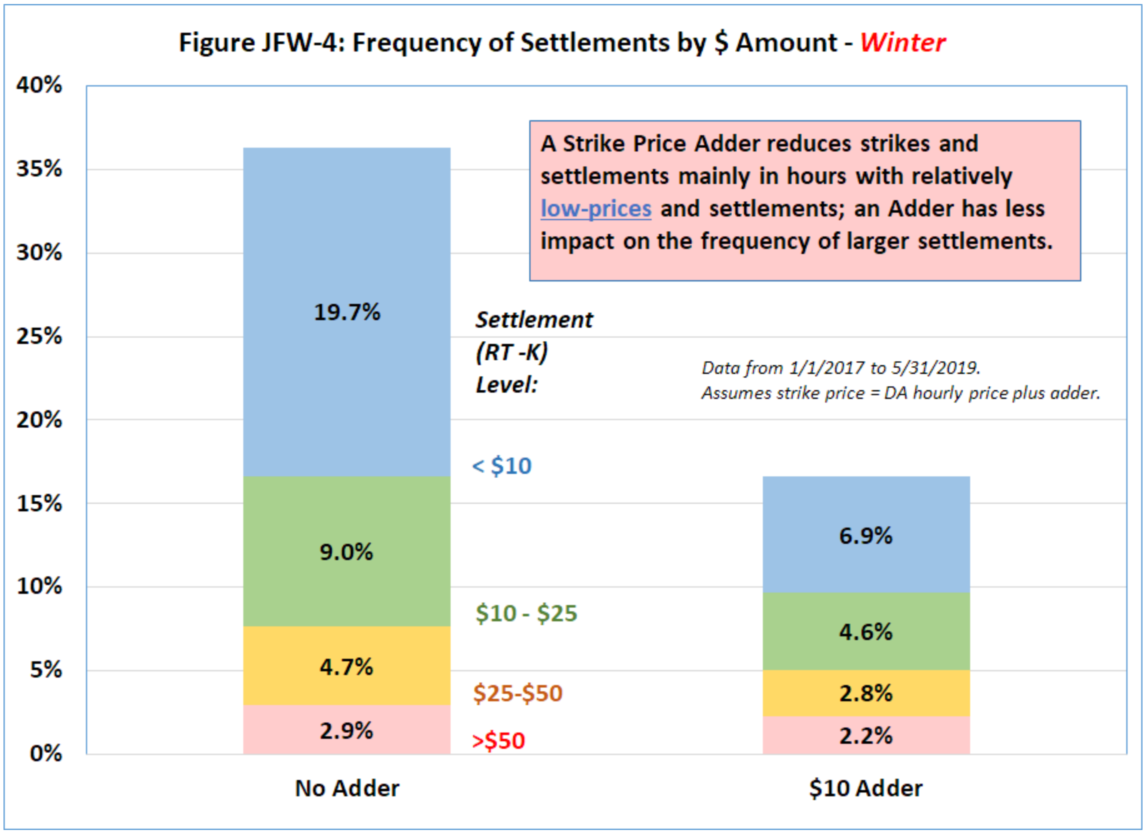
eliminate few strikes when RT prices are high and the Energy Option incentives are desired to contribute to energy security.

Figure JFW-2 provides the same information, limited to the Winter hours (December through February) of the same historical period. The analysis leads to the same conclusion: the Strike Price Adder reduces many strikes when prices are low, and has far less impact on the frequency of strikes when prices are high and the full incentives are desired.

Q 133: Have you performed analysis of the impact of the $10/MWh Strike Price Adder on the magnitude of Energy Option settlements?

A: Yes. I examined the same data to see the impact of the Strike Price Adder on the magnitude of Energy Option settlements. This analysis is summarized in Figures JFW-3





(all hours) and JFW-4 (Winter hours). With no adder, in 24.5% of the hours the Energy Option strikes with a settlement under $10/MWh. With the $10/MWh Strike Price Adder, the frequency of such small settlements falls to 7.1%. The frequency of large settlements over $50/MWh declines much less, from 1.6% of the hours with no adder, to 1.2% with the $10 adder. The results for winter hours (Figure JFW-4) are similar.

This analysis shows that the Strike Price Adder mainly reduces the magnitude of Energy Option settlement in low-price hours when energy security is less of a concern, and with a much smaller impact in higher price hours.

Based on this data, the $10/MWh Strike Price Adder reduces the expected dollar amount of settlements by 38% in winter hours and by 47% in non-winter hours.

These results show that the Strike Price Adder can reduce cost and risk, especially when prices are lower and energy security is not a concern or less of a concern, while having little impact on the ESI incentives when prices are higher and energy security might be more of a concern.

Q 134: In reducing the expected settlement under the Energy Option, does the Strike Price Adder reduce the incentive to acquire fuel by the same amount?

A: No. Recall first that Energy Option clearing prices will reflect the expected settlement, so resources will see similar reductions in the settlement and in the Energy Option price, likely almost a wash. More important, recall that the incentive to acquire fuel created by the Energy Option reflects the *difference* in the expected settlement if fuel is not acquired compared to the expected settlement under the lower prices anticipated if a resource acquires fuel and runs. For resources that do not believe their decision affects price very much, this incentive is small to begin with. In addition, most of the price impact that affects incentives likely occurs under potentially high RT outcomes, while the Strike Price Adder would only remove incentives occurring at a small subset of RT price outcomes below the strike price level, as the ISO has acknowledged (discussed below).

Q 135: The Whitepaper exhibits an "incentive profile curve", which appears to suggest that incentives fall sharply when the strike price exceeds a generator's marginal cost. Please comment on this.

A: The illustrated "incentive profile curve,"[106] Whitepaper Figure 5-2 (reproduced below), purportedly shows how the incentive to acquire fuel declines as the strike price is increased. However, it is based on the extreme assumptions of Example 2 in the Whitepaper, under which the RT price would spike from $40/MWh to $90/MWh under

[106] The incentive profile curve is on Whitepaper p. 96.

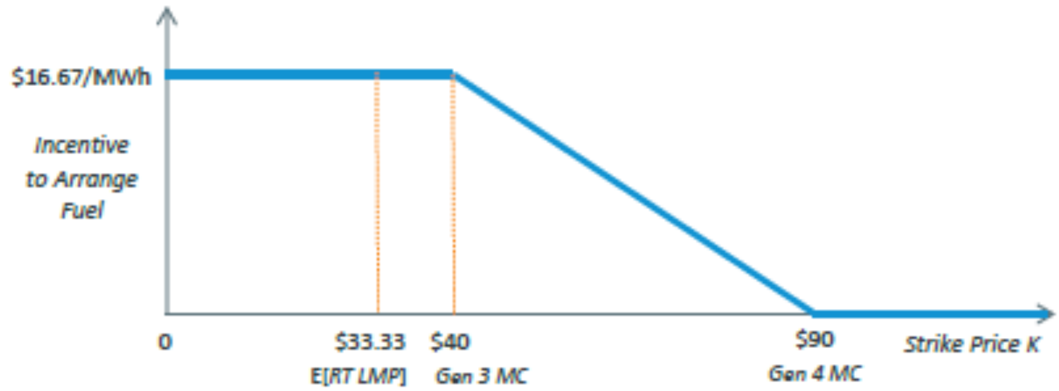


Figure 5-2. Generator 3's Incentive Profile in Example 2

the High Demand scenario if the generator does not acquire fuel.[107] This extreme assumption determines the shape of the illustrated incentive profile curve, as the Whitepaper acknowledges:[108]

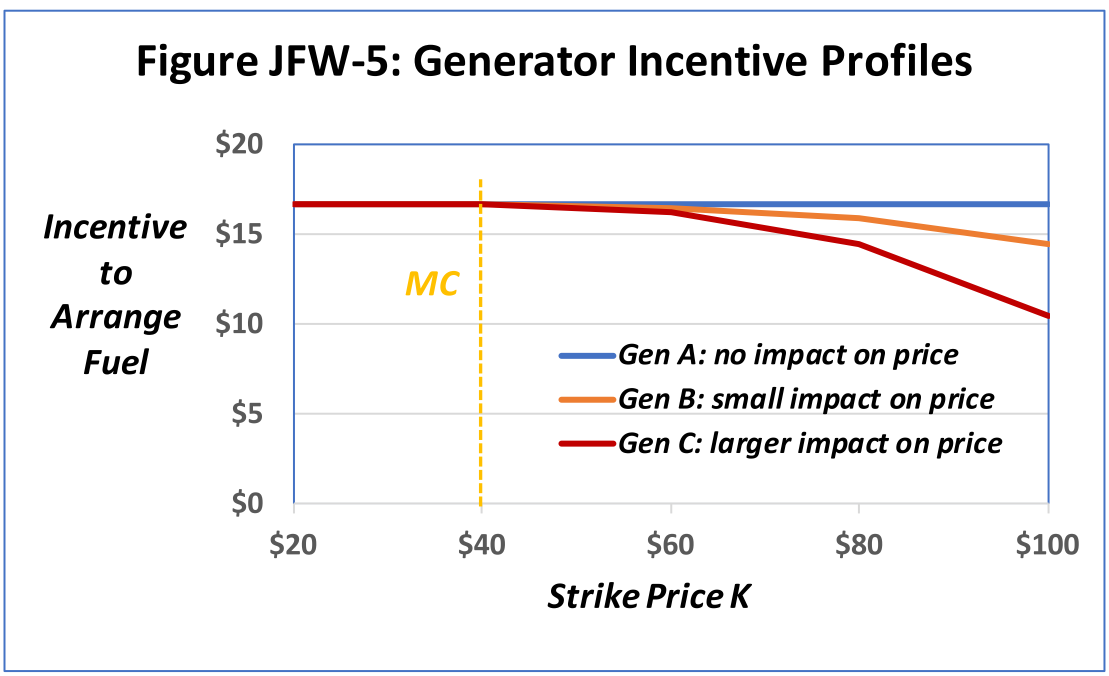
> "However, the linear decline above the generator's marginal cost in Figure 5-2 is an artifact of the discrete price outcomes in Example 2; in general, the downward sloping segment above a generator's marginal cost is nonlinear, with a shape determined by the full probability distribution of the real-time price with and without the generator's energy supply."

In fact, for resources that do not believe their output, or lack of output, appreciably affects prices, the incentive does not decline at all when the strike price rises above marginal cost. And for resources that do believe their output can affect RT price outcomes significantly, the incentive would decline very slowly as the strike price rises

[107] Whitepaper p. 92, Tables 5-2 and 5-3.
[108] Whitepaper p. 98 footnote 74.

above marginal cost, because the lost incentive is based on the different price outcomes in the small range between marginal cost and the strike price.

More realistic incentive profile curves are shown in Figure JFW-5. In this graphic, Gen A does not believe its output appreciably affects price. Therefore, its incentive profile is not affected by a higher strike price. Gen B anticipates its output has a small impact on price, so as the strike price rises above its marginal cost (shown as $40/MWh), its incentive begins to decline. The decline is very slow at first, because the reduction in incentive reflects both the low probability of RT price outcomes in the price range between MC and the strike price, and also the small impact its output is expected to have on prices at that low price level. Gen C illustrates a generator that believes its output has a larger impact on price, and its incentives decline somewhat more at each strike price level.



In any case, the Whitepaper ultimately concludes that "small inaccuracies in setting the strike price "at the money" should not matter much – within limits"[109] and this conclusion applies to a modest Strike Price Adder, such as the $10/MWh proposed in the NEPOOL Alternative.

Q 136: The ESI Filing claims, contrary to your analysis, that a reduction in incentives from a Strike Price Adder "appears to be most severe during periods when the system is stressed, suggesting that such an adder will undermine the design's objectives most significantly when energy security is most critical to the region." Please comment.

A: I disagree with this claim, which is counter-intuitive – at higher RT prices, the Strike Price Adder is a smaller fraction of the RT price, and likely to have a smaller impact.

Notably, no citation is provided in the ESI Filing for this claim. The Whitepaper discusses the Energy Option strike prices at pp. 73-79 and pp. 95-101, and makes no such claim. The claim is apparently based on an ISO presentation in February 2020 that made such a claim,[110] which as I will explain was flawed.

Q 137: Please describe the ISO's analysis that may be the basis for this claim.

A: Using data from the Impact Assessment, the ISO counted the number of MW for which the Strike Price Adder would move the strike price from below to above the resource's marginal cost. This is a first screen for whether there is potentially any impact on incentive; only when the adder moves the strike price above marginal cost is there any possibility that incentives were affected.

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[109] Whitepaper p. 101.
[110] Chris Geissler, ISO New England, *How adding a 'bias' to the strike price may impact resource incentives*, NEPOOL Markets Committee meeting February 11-13, 2020, p. 21.

The ISO's analysis found that for 91 percent to 98 of the MW providing the Energy Option across all hours in the three Impact Assessment cases, a \$10/MWh strike price adder would not move the strike price above marginal cost, and, therefore, would have zero impact on incentives.[111] For the remaining small percent of MW, the analysis could make no conclusion about whether there was an impact on incentive or not; the analysis did not attempt to evaluate whether the impact could be 0%, 1%, or 3% or more.

The ISO's presentation also identified the same percentages of MW based on different RT price levels, and found that the small percentages of MW that could be affected were somewhat higher at higher price levels. Based on that finding (which, as I will discuss below, was flawed), the presentation over-reached and made the claim, "Analysis suggests a strike bias appears to impact incentives more significantly during stressed conditions." Again, there was no analysis of impact on incentives, only of the fraction of sellers who potentially could see a non-zero impact.

Q 138: Please explain why you reject the ISO's assertion that the impact of the Strike Price Adder could be more severe when the system is under stress.

A: First, as noted above, the ISO performed no evaluation of incentive impacts; its analysis only calculated the percentage of MW selling the Energy Option whose incentives could be affected, and found that the percentages were small. The assertion of incentive impact was criticized during the presentation, and the ISO backed away from it.

In addition, and as pointed out at the time, the ISO's analysis exhibited the following significant flaws:

[111] *Id*, p. 22.

1. The analysis did not use actual strike prices, but instead used DA energy prices in place of strike prices, despite strike prices being available within the Impact Assessment. This removed a major contributor to the "noise" in the strike price, from inaccuracy in predicting the DA and RT energy prices, that the Strike Price Adder reduces.

2. The analysis also did not use the correct resource marginal cost for the classification; it used DA marginal costs, even though the relevant post-DA marginal costs were available. When the circumstances are developing such that RT prices are likely to spike, resources likely see this in the market and are re-evaluating their marginal costs higher. By using DA marginal costs, ISO ignores this, and calculates a higher number of MW affected by the strike price adder.

3. The analysis also did not use the RT prices used for the Energy Option settlement calculation in the Impact Assessment; instead, it used endogenous RT prices resulting from the model dispatch, which are much less volatile.

In light of these flaws, I reject the ISO's analysis and its counter-intuitive assertion that at higher RT prices, when the Strike Price Adder is a small fraction of price, the quantity of resources for whom the adder could influence incentive increases.

Q 139: Could a strike price adder affect the selection of energy and energy option providers through the co-optimization of the DA market?

A: No, a modest adder (such as the NEPOOL Alternative's $10/MWh) would not appreciably affect DA energy and option offers and the efficiency of the DA co-optimization. Resources with higher marginal costs are expected to generally offer the

Energy Option at higher prices, other things equal, because the higher a resource's marginal cost, the greater the option settlement exposure that is not hedged by RT revenues, leading to higher risk premium.

However, it should not be expected that option offer prices strictly reflect resource marginal costs. There are multiple factors and uncertainties that will be reflected in Energy Option offer prices, as discussed in an earlier section of my affidavit.

1. The main component is the expected option settlement. Market participants are likely to have a wide range of forecasts in this regard.

2. Risk premiums will also reflect risks of not being able to run in RT due to forced outages or other causes, in addition to an owner's risk preferences.

Thus, the expected settlement and risk premium reflected in Energy Option offers are likely to vary widely, even for resources with the same marginal cost.

Energy Option offer prices may also reflect costs to arrange fuel that would be recovered through RT operation, opportunity costs, and some amount of economic withholding, additional factors that would lead offers to not reflect heat rates and marginal costs.

The ISO's analysis, discussed above, suggests that with the $10 Strike Price Adder, only a small fraction of resources may have marginal cost below the strike price. Because this is relatively few resources, and because there are many other factors that go into the option offer prices, I do not see this as causing any appreciable impact on the DA dispatch.

Q 140: Would a strike price adder create or enhance any unwanted incentives, such as to offer the Energy Option with no intention of being able to run in RT?

A: No. A strike price adder reduces the expected settlement, which reduces the settlement a seller who cannot run is exposed to. That might seem to reduce the incentive to arrange fuel. However, the reduced cost of the settlement should be reflected in reduced offer prices to provide the option, and reduced option clearing prices; that is, the savings to sellers from a lower expected settlement should roughly equal the reduced revenue from a lower option clearing price. This would leave any incentive to offer "uncovered" energy options unchanged by the adder.

Q 141: Does this complete your testimony?

A: Yes it does.

I certify, under penalty of perjury, that the forgoing is true and correct to the best of my knowledge and belief.

Executed on this 11th day of May, 2020.

James F. Wilson

James F. Wilson
Principal, Wilson Energy Economics

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SUMMARY

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Analysis of provisions to enhance resource fuel security in day-ahead and real-time wholesale electricity markets.
- Evaluated peak electric load forecasts and enhancements to load forecasting methodologies.
- Evaluated a probabilistic analysis to determine the electric generating capacity reserve margin to satisfy resource adequacy criteria.
- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.

- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
Principal

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.

- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.
- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.

- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.

- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate*,* 1985-1992*.*

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

Proceedings on Motion of the Commission to Consider Resource Adequacy Matters, New York Public Service Commission Case No. 19-E-0530, Reply Affidavit on behalf of Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, New Yorkers for Clean Power, Environmental Advocates of New York, and Vote Solar, January 31, 2020.

In the Matter of the Application of DTE Electric Company for Reconciliation of its Power Supply Cost Recovery Plan for the 12-month Period Ending December 31, 2018, Michigan Public Service Commission Case No. U-20203, Direct Testimony on behalf of Michigan Environmental Council, January 17, 2020.

In Re: Joint Application of Longview Power II, LLC and Longview Renewable Power, LLC to Authorize the Construction and Operation of Two Wholesale Electric Generating Facilities and One High-Voltage Electric Transmission Line in Monongalia County, Public Service Commission of West Virginia Case No. 19-0890-E-CS-CN, Direct Testimony on behalf of Sierra Club, January 3, 2020; testimony at hearings January 30, 2019.

In Re: Alabama Power Company Petition for a Certificate of Convenience and Necessity, Alabama Public Service Commission Docket No. 32953, Direct Testimony on Behalf of Energy Alabama and Gasp, December 4, 2019; testimony at hearings March 11, 2020.

In the Matter of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Standard Offer, Avoided Cost Methodologies, and Form Contract Power Purchase Agreements, South Carolina Public Service Commission Docket Nos. 2019-185-E and 2019-186-E, Direct Testimony on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, September 11, 2019; surrebuttal testimony, October 11, 2019; direct and surrebuttal testimony at hearings, October 22, 2019.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2019 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-20221, Direct Testimony on behalf of Michigan Environmental Council, May 28, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - ORDC), Affidavit in Support of the Protest of the Clean Energy Advocates, May 15, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - Transition), Affidavit in Support of the Protests of the PJM Load/Customer Coalition and Clean Energy Advocates, May 15, 2019.

In Re: Georgia Power Company's 2019 Integrated Resource Plan, Georgia Public Service Commission Docket No. 42310, Direct Testimony on Behalf of Georgia Interfaith Power & Light and the Partnership For Southern Equity, April 25, 2019; testimony at hearings May 14, 2019.

PJM Interconnection, L.L.C., FERC Docket No. EL19-63 (RPM Market Supplier Offer Cap), Affidavit in Support of the Complaint of the Joint Consumer Advocates, April 15, 2019.

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 157, Review and Evaluation of the Load Forecasts, and Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues, with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans, Attachments 3 and 4 to the comments of Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council, March 7, 2019; presentation at technical conference, January 8, 2020.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018, North Carolina Utilities Commission Docket No. E-100 Sub 158, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing, Attachment B to the Initial Comments of the Southern Alliance for Clean Energy, February 12, 2019.

PJM Interconnection, L.L.C., FERC Docket No. ER19-105 (RPM Quadrennial Review), Affidavit in Support of the Limited Protest and Comments of the Public Interest Entities, November 19, 2018.

PJM Interconnection, L.L.C., FERC Docket No. EL18-178 (MOPR and FRR Alternative), Affidavit in Support of the Comments of the FRR-RS Supporters, October 2, 2018; Reply Affidavit on behalf of Clean Energy and Consumer Advocates, November 6, 2018.

Virginia Electric and Power Company's 2018 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2018-00065, Direct Testimony on behalf of Environmental Respondents, August 10, 2018; testimony at hearings September 25, 2018; Supplemental Testimony, April 16, 2019.

In the Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates, etc., Public Utilities Commission of Ohio Case No. 17-32-EL-AIR et al, Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, June 25, 2018; deposition, July 3, 2018; testimony at hearings, July 19, 2018.

In the Matter of the Application of DTE Gas Company for Approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 Months ending March 31, 2019, Michigan Public Service Commission Case No. U-18412, Direct Testimony on behalf of Michigan Environmental Council, June 7, 2018.

Constellation Mystic Power, L.L.C., FERC Docket No. ER18-1639-000 (Mystic Cost of Service Agreement), Affidavit in Support of the Comments of New England States Committee on Electricity, June 6, 2018; prepared answering testimony, August 23, 1018.

New England Power Generators Association, Complainant v. ISO New England Inc. Respondent, FERC Docket No. EL18-154-000 (re: capacity offer price of Mystic power plant), Affidavit in Support of the Protest of New England States Committee on Electricity, June 6, 2018.

PJM Interconnection, L.L.C., FERC Docket No. ER18-1314 (Capacity repricing or MOPR-Ex), Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, May 7, 2018; reply affidavit, June 15, 2018.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2018 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18403, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, April 20, 2018.

Virginia Electric and Power Company’s 2017 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2017-00051, Direct Testimony on behalf of Environmental Respondents, August 11, 2017; testimony at hearings September 26, 2017.

Ohio House of Representatives Public Utilities Committee hearing on House Bill 178 (Zero Emission Nuclear Resource legislation), Opponent Testimony on Behalf of Natural Resources Defense Council, May 15, 2017.

In the Matter of the Application of Atlantic Coast Pipeline, Federal Energy Regulatory Commission Docket No. CP15-554, Evaluating Market Need for the Atlantic Coast Pipeline, Attachment 2 to the comments of Shenandoah Valley Network *et a*l, April 6, 2017.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2017 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18143, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 22, 2017.

In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company’s Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.

In the Matter of Integrated Resource Plans and Related 2016 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 147, Review and Evaluation of the Peak Load Forecasts and Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans, Attachments A and B to the comments of the Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club, February 17, 2017.

In the Matter of the Tariff Revisions Designated TA285-4 filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-16-066, Testimony on Behalf of Matanuska Electric Association, Inc., February 7, 2017, testimony at hearings, June 21, 2017.

PJM Interconnection, L.L.C., FERC Docket No. ER17-367 (seasonal capacity), Prepared Testimony on Behalf of Advanced Energy Management Alliance, Environmental Law & Policy Center, Natural Resources Defense Council, Rockland Electric Company and Sierra Club, December 8, 2016; Declaration in support of Protest of Response to Deficiency Letter, February 13, 2017.

Natural Resources Defense Council, Sierra Club, and Union of Concerned Scientists v. Federal Energy Regulatory Commission, U.S. District Court of Appeals for the D.C. Circuit Case No. 16-1236 (Capacity Performance), Declaration, September 23, 2016.

Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2016, West Virginia Public Service Commission Case No. 15-1256-G-390P, and Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2017, West Virginia Public Service Commission Case No. 16-0922-G-390P, Direct Testimony on behalf of the West Virginia Propane Gas Association, September 9, 2016.

Application of Chesapeake Utilities Corporation for a General Increase in its Natural Gas Rates and for Approval of Certain Other Changes to its Natural Gas Tariff, Delaware P.S.C. Docket No. 15-1734, Direct Testimony on behalf of the Delaware Association Of Alternative Energy Providers, Inc., August 24, 2016.

Virginia Electric and Power Company's 2016 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2016-00049, Direct Testimony on behalf of Environmental Respondents, August 17, 2016; testimony at hearings October 5, 2016.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-17920, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 14, 2016.

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 11, 2015; deposition, September 30, 2015; supplemental deposition, October 16, 2015; testimony at hearings, October 21, 2015; supplemental testimony December 28, 2015; second supplemental deposition, December 30, 2015; testimony at hearings January 8, 2016.

Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.

ISO New England Inc. and New England Power Pool Participants Committee, FERC Docket No. ER15-2208 (Winter Reliability Program), Testimony on Behalf of the New England States Committee on Electricity, August 5, 2015.

Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.

In the Matter of the Tariff Revisions Filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-14-111, Testimony on Behalf of Matanuska Electric Association, Inc., May 13, 2015.

In the Matter of the Application of Ohio Edison Company et al for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel and Northeast Ohio Public Energy Council, December 22, 2014; deposition, February 10, 2015; supplemental testimony May 11, 2015; second deposition May 26, 2015; testimony at hearings, October 2, 2015; second supplemental testimony December 30, 2015; third deposition January 8, 2016; testimony at hearings January 19, 2016; rehearing direct testimony June 22, 2016; fourth deposition July 5, 2016; testimony at hearings July 14, 2016.

PJM Interconnection, L.L.C., FERC Docket No. ER14-2940 (RPM Triennial Review), Affidavit in Support of the Protest of the PJM Load Group, October 16, 2014.

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-841-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 26, 2014; deposition, October 6, 2014; testimony at hearings, November 5, 2014.

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 13-2385-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 6, 2014; deposition, May 29, 2014; testimony at hearings, June 16, 2014.

PJM Interconnection, L.L.C., FERC Docket No. ER14-504 (clearing of Demand Response in RPM), Affidavit in Support of the Protest of the Joint Consumer Advocates and Public Interest Organizations, December 20, 2013.

New England Power Generators Association, Inc. v. ISO New England Inc., FERC Docket No. EL14-7 (administrative capacity pricing), Testimony in Support of the Protest of the New England States Committee on Electricity, November 27, 2013.

Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.

ANR Storage Company, FERC Docket No. RP12-479 (storage market-based rates), Prepared Answering Testimony on behalf of the Joint Intervenor Group, April 2, 2013; Prepared Cross-answering Testimony, May 15, 2013; testimony at hearings, September 4, 2013.

In the Matter of the Application of The Dayton Power and Light Company for Approval of its Market Rate Offer, Public Utilities Commission of Ohio Case No. 12-426-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, March 5, 2013; deposition, March 11, 2013.

PJM Interconnection, L.L.C., FERC Docket No. ER13-535 (minimum offer price rule), Affidavit in Support of the Protest and Comments of the Joint Consumer Advocates, December 28, 2012.

In the Matter of the Application of Ohio Edison Company, et al for Authority to Provide for a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 12-1230-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 21, 2012; deposition, May 30, 2012; testimony at hearings, June 5, 2012.

PJM Interconnection, L.L.C., FERC Docket No. ER12-513 (changes to RPM), Affidavit in Support of Protest of the Joint Consumer Advocates and Demand Response Supporters, December 22, 2011.

People of the State of Illinois *ex rel*. Leon A. Greenblatt, III v Commonwealth Edison Company, Circuit Court of Cook County, Illinois, deposition, September 22, 2011; interrogatory, Feb. 22, 2011.

In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System Operator, Inc., Missouri PSC Case No. EO-2011-0128, Testimony in hearings, February 9, 2012; Rebuttal Testimony and Response to Commission Questions On Behalf Of The Missouri Joint Municipal Electric Utility Commission, September 14, 2011.

PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.

PJM Interconnection, L.L.C., FERC Docket No. ER11-2288 (demand response "saturation"), Affidavit in Support of Protest and Comments of the Joint Consumer Advocates, December 23, 2010.

North American Electric Reliability Corporation, FERC Docket No. RM10-10, Comments on Proposed Reliability Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 23, 2010.

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, Maryland Public Service Commission Administrative Docket PC 22, Comments and Responses to Questions On Behalf of Southern Maryland Electric Cooperative, October 15, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-1063-004 (PJM compliance filing on pricing during operating reserve shortages): Affidavit In Support of Comments and Protest of the Pennsylvania Public Utility Commission, July 30, 2010.

ISO New England, Inc. and New England Power Pool, FERC Docket No. ER10-787 (minimum offer price rules): Direct Testimony On Behalf Of The Connecticut Department of Public Utility Control, March 30, 2010; Direct Testimony in Support of First Brief of the Joint Filing Supporters, July 1, 2010; Supplemental Testimony in Support of Second Brief of the Joint Filing Supporters, September 1, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-006 (RPM incremental auctions): Affidavit In Support of Protest of Indicated Consumer Interests, January 19, 2010.

In the Matter of the Application of Ohio Edison Company, et al for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Public Utilities Commission of Ohio Case No. 09-906-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, December 7, 2009; deposition, December 10, 2009, testimony at hearings, December 22, 2009.

Application of PATH Allegheny Virginia Transmission Corporation for Certificates of Public Convenience and Necessity to Construct Facilities: 765 kV Transmission Line through Loudon, Frederick and Clarke Counties, Virginia State Corporation Commission Case No. PUE-2009-00043: Direct Testimony on Behalf of Commission Staff, December 8, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit on Proposed Changes to the Reliability Pricing Model on behalf of RPM Load Group, January 9, 2009; Reply Affidavit, January 26, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.

Maryland Public Service Commission et al v. PJM Interconnection, L.L.C., FERC Docket No. EL08-67-000: Affidavit in Support Complaint of the RPM Buyers, May 30, 2008; Supplemental Affidavit, July 28, 2008.

PJM Interconnection, L.L.C., FERC Docket No. ER08-516: Affidavit On PJM's Proposed Change to RPM Parameters on Behalf of RPM Buyers, March 6, 2008.

PJM Interconnection, L.L.C., Reliability Pricing Model Compliance Filing, FERC Docket Nos. ER05-1410 and EL05-148: Affidavit Addressing RPM Compliance Filing Issues on Behalf of the Public Power Association of New Jersey, October 15, 2007.

TXU Energy Retail Company LP v. Leprino Foods Company, Inc., US District Court for the Northern District of California, Case No. C01-20289: Testimony at trial, November 15-29, 2006; Deposition, April 7, 2006; Expert Report on Behalf of Leprino Foods Company, March 10, 2006.

Gas Transmission Northwest Corporation, Federal Energy Regulation Commission Docket No. RP06-407: Reply Affidavit, October 26, 2006; Affidavit on Behalf of the Canadian Association of Petroleum Producers, October 18, 2006.

PJM Interconnection, L.L.C., Reliability Pricing Model, FERC Docket Nos. ER05-1410 and EL05-148: Supplemental Affidavit on Technical Conference Issues, June 22, 2006; Supplemental Affidavit Addressing Paper Hearing Topics, June 2, 2006; Affidavit on Behalf of the Public Power Association of New Jersey, October 19, 2005.

Maritimes & Northeast Pipeline, L.L.C., FERC Docket No. RP04-360-000: Prepared Cross Answering Testimony, March 11, 2005; Prepared Direct and Answering Testimony on Behalf of Firm Shipper Group, February 11, 2005.

Dynegy Marketing and Trade v. Multiut Corporation, US District Court of the Northern District of Illinois, Case. No. 02 C 7446: Deposition, September 1, 2005; Expert Report in response to Defendant's counterclaims, March 21, 2005; Expert Report on damages, October 15, 2004.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.04-03-021: Prepared Testimony, Policy for Throughput-Based Backbone Rates, on behalf of Pacific Gas and Electric Company, May 21, 2004.

Gas Market Activities, California Public Utilities Commission Order Instituting Investigation I.02-11-040: Testimony at hearings, July, 2004; Prepared Testimony, Comparison of Incentives Under Gas Procurement Incentive Mechanisms, on behalf of Pacific Gas and Electric Company, December 10, 2003.

Application of Red Lake Gas Storage, L.P., FERC Docket No. CP02-420, Affidavit in support of application for market-based rates for a proposed merchant gas storage facility, March 3, 2003.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.01-10-011: Testimony at hearings, April 1-2, 2003; Rebuttal Testimony, March 24, 2003; Prepared

Testimony, Performance of the Gas Accord Market Structure, on behalf of Pacific Gas and Electric Company, January 13, 2003.

Application of Wild Goose Storage, Inc., California Public Utilities Commission proceeding A.01-06-029: Testimony at hearings, November, 2001; Prepared testimony regarding policies for backbone expansion and tolls, and potential ratepayer benefits of new storage, on behalf of Pacific Gas and Electric Company, October 24, 2001.

Public Utilities Commission of the State of California v. El Paso Natural Gas Co., FERC Docket No. RP00-241: Testimony at hearings, May-June, 2001; Prepared Testimony on behalf of Pacific Gas and Electric Company, May 8, 2001.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.99-09-053: Prepared testimony regarding market power consequences of divestiture of hydroelectric assets, December 5, 2000.

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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

March 2020

Attachment B

Affidavit of Denis Bergeron

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)	Docket Nos. EL18-182-000
	)	ER20-1567-000

AFFIDAVIT OF DENIS BERGERON
IN SUPPORT OF THE PROTEST OF THE
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

Q. Please state your name and by whom, and in what capacity, you are employed.

A. My name is Denis Bergeron. I am employed as a senior utility analyst / Regional Grid Coordinator for the Maine Public Utilities Commission, 101 Second Street, Hallowell, Maine, Station 18, Augusta, ME 04333.

Q. Please summarize your educational background.

A. I hold a Mechanical Engineering degree from the University of Utah, and degrees in Business Management and Recreation Management from the University of Maine.

Q. Please briefly summarize your professional experience

A. I am a registered professional engineer in Maine. I have worked for the Maine Public Utilities Commission for over 30 years on energy issues in both the electric and gas utility industries. During that time, I have been involved in the review and modeling of both electric and gas utility integrated resource plans, directed the state's gas pipeline safety program, directed the state's energy efficiency programs, and been involved in the development and implementation of post restructuring market rules at both the wholesale and retail levels. I serve on the Northeast Power Coordinating Council's (NPCC) Board of Directors as one of two Sector 6 (State and Provincial Regulatory and/or Governmental Authorities) representatives. My current focus is on the ISO New England (ISO-NE) wholesale electric markets and regional transmission and resource adequacy planning.

Q. What is the purpose of your testimony?

A. In this testimony, I address the interaction of ISO-NE's Energy Security Improvements (ESI) proposal with North American Electric Reliability Corporation (NERC) and NPCC reliability standards. With its filing, ISO-NE seeks to establish a new Ancillary Service market and has referenced certain mandatory reliability standards and its own Operating Procedures as foundational requirements relevant to the development of ESI. It is important to state at the outset that during the stakeholder process ISO-NE staff confirmed that ISO-NE is currently in compliance with all NERC and NPCC reliability requirements and is operating completely within the parameters of its own Operating Procedures. This testimony focuses primarily on one product—Replacement Energy Reserves (RER)—proposed by ISO-NE in its ESI filing.

Q. Have you reviewed the testimony of Peter T. Brandien, included as Attachment A of ISO-NE's ESI filing?

A. Yes.

Q. Does Mr. Brandien describe certain NERC and NPCC standards related to energy supply planning and reserve requirements?

A. Yes.

Q. Do the NERC and NPCC standards that Mr. Brandien discusses require the implementation of the ESI proposal?

A: No. As ISO-NE stated in the stakeholder process used to review ESI, it is already in compliance with all of these standards and procedures under its existing construct, without ESI. The NERC and NPCC standards provide flexibility to Balancing

Authorities (BAs) in how they meet these mandatory requirements. I explain this in greater detail below in discussing RER.

Q. What are the NERC and NPCC standards and procedures upon which ISO-NE has based the development of RER?

A. **NERC Standards:** NERC is the national Electric Reliability Organization responsible for promulgating and enforcing mandatory reliability standards for power system operators. The NERC standards referred to by ISO-NE are discussed briefly below.

NERC-TOP-002-4 – Operations Planning, Requirement R4, requires BAs to have Operating Plans for the next-day that address each of the following criteria: expected generation resource commitment and dispatch, interchange scheduling, demand patterns, and capacity and energy reserve requirements.

NERC BAL-002-3 (Disturbance Control Standard) – Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R.1, requires ISO-NE, as the BA, to maintain and activate Contingency Reserve to respond to all Reportable Balancing Contingency Events in order to restore the BA's Area Control Error (ACE) within prescribed time limits.

NERC BAL-002-3, Requirement R.2, requires the BA Operating Plan include a process "to determine the Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than . . . the Most Severe Single Contingency available for maintaining system reliability."

NPCC Standards: NPCC is one of six Regional Entities which, together with NERC, make up the Electric Reliability Organization Enterprise. As a Regional

Entity, NPCC may develop regional reliability standards more stringent than national standards and it performs compliance assessment and enforcement of continent-wide (NERC) and regional reliability standards (NPCC). It also coordinates system planning, design and operations, and assessment of reliability within its region. NPCC Regional Reliability Reference Directory #5 (Reserve), Section 5 of Directory #5 is one regional standard that is more stringent than those established by NERC. Section 5 contains “NPCC Full Member More Stringent Criteria Requirements and Measures for reserves.” Directory 5 is more stringent than the NERC standards in that it includes a requirement for additional reserves beyond the first contingency event equal to one-half its second contingency loss. It also contains a provision for sustainability: synchronized reserve, ten-minute reserve, and thirty-minute reserve must be sustainable for at least one hour from the time of activation.

Q. Do these requirements require the purchase in the Day Ahead Market of Options to supply RER?

A: No.

Q. Can you please explain why not?

A. Yes. NERC and NPCC standards require BAs to have a specific amount of ten-minute and thirty-minute operating reserves and provide timelines for restoration if there are deficiencies. However, the NERC and NPCC standards do not require a BA to procure reserves to replace reserves, as RER would have ISO-NE do. Directory 5—which is more stringent than the related NERC standards as explained above—provides many restoration options available to BAs.

Q. **Can you please describe those options?**

A. Yes.

Appendix B of NPCC Directory 5 lists options for restoring ten-minute reserves:

3.1 Actions When Becoming Deficient in **Ten-Minute Reserve**

To minimize the magnitude and duration of a **Ten-Minute Reserve** deficiency, a Balancing Authority may implement any or all of the actions below, in no implied order:

- Commit sufficient off-line supply-side **resources** to create additional **ten-minute reserve** within the restoration period.
- Recall applicable exports respecting Balancing Authority **operating procedures**. The Source Balancing Authority of the applicable exports shall give proper notification to the Sink Balancing Authority.
- Obtain additional **resources** from outside the Balancing Authority in accordance with regional and local practices. These additional **resources** shall not be from the portion of another Balancing Authority's **reserve** that is needed to meet the other Balancing Authority's **reserve** requirements in coincident hours.
- Recall planned generator outages and coordinate with the Reliability Coordinator for possible assistance available by recalling transmission outages (or taking other actions) that will increase **reserve** or **transfer capability** if it can reasonably be expected that additional **resources** are available to assist in reducing or eliminating the shortage.
- Count interruptible customer **load** that can be interrupted within ten minutes in its **ten-minute reserve**, if it has not already been counted.
- Count voltage reduction that can be implemented within ten minutes in its **ten-minute reserve**, if it has not already been counted.
- Consider the use of Public Appeals if sufficient time exists to activate them, or if the shortage is expected to last for an extended period.

Appendix B provides similar options for restoring thirty-minute reserves:

To minimize the magnitude and duration of a **thirty-minute reserve** deficiency, a Balancing Authority may implement any or all of the actions below, in no implied order:

- Obtain additional **resources** from outside the Balancing Authority in accordance with regional and local practices. These additional **resources** shall not be from the portion of another Balancing Authority's **reserve** that is needed to meet the other Balancing Authority's **reserve** requirements in coincident hours. Emergency energy purchases between Balancing Authority Areas are optional.
- Recall planned generator outages and coordinate with the Reliability Coordinator for possible assistance available by recalling transmission outages that will increase **reserve** or **transfer capability** if it can reasonably be expected that additional **resources** are available to assist in reducing or eliminating the shortage.
- Recall applicable exports or convert applicable exports to a recallable product and include this energy and/or **capacity** in its **thirty-minute reserve,** while respecting Balancing Authority operating procedures. The Source Balancing Authority of the

applicable exports gives proper notification to the Sink Balancing Authority if this action is taken**.**

Q. What conclusions do you draw from analyzing these options in Directory 5?

A. For restoration of 10-minute reserves, committing off-line resources is only one of several options. The same is true for the restoration of thirty-minute reserves. There is simply no requirement to activate only off-line resources if reserves are depleted. Reserves can be restored through any of the other methods listed. Under the ESI design, ISO-NE is forcing consumers to pay for using "the committing offline resources" option even though other options are available to meet the standard.

Q. In developing its Operating Plan, is a BA required to account for all the off-line resources it might have to commit if a contingency occurred or if reserves were depleted so it would be able to replace the reserves?

A. No. There is no requirement to plan for stacking an additional layer of reserves to replace reserves in the Operating Plan. There are several reason for this. First, contingency events are extremely rare and reserve depletions not associated with a contingency event do not happen often; second, there are reserves already in place in the event that they do occur; third, activating off-line resources is only one of several options available to restore reserves; and finally, the limited additional reliability benefit of such a requirement is not likely to justify the additional cost of such a requirement. I have not seen any other Regional Transmission Organization (RTO) suggest that either NERC or NPCC criteria require obtaining reserves day-ahead to replace reserves in the unlikely possibility of an operating day contingency event or other reserve depletion. Stated another way, under NERC/NPCC rules, the BA would have several options to replenish reserves if a contingency event or other reserve depletion did occur. Since this does not happen often, the BA would not be expected to purchase reserves upon reserves day ahead just on the off chance that reserves need to be replenished.

Q. Have you analyzed any data regarding how often contingency events or reserve activations have occurred in ISO-NE?

A. Reserve activations are emergency actions that occur infrequently. Between 2007 and 2019, reserve outages have averaged 8.25 hours per year or 0.09% of annual hours.[1] Given the historically infrequent reserve deficiency occurrences, the various actions available to replenish the reserves, and the fact that no other RTO has a replacement reserves ancillary service that in effect pre-purchases reserves to replace reserves, the unproven benefits of RER do not appear to outweigh the costs for the service.

Q. Does this conclude your testimony?

A. Yes.

[1] The data upon which this calculation is based can be found at the following link: https://www.iso-ne.com/search?query=reserve%20constraint%20penalty%20factor.

I certify, under penalty of perjury, that the forgoing is true and correct to the best of my knowledge and belief.

Executed on this 12th day of May, 2020.

/s/ Denis Bergeron

Denis Bergeron