July 15, 2015

BY ELECTRONIC FILING

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ISO New England Inc. and New England Power Pool, Filings of Winter Reliability Programs; Docket No. ER15-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, hereby submits with this cover transmittal letter two alternative versions of Tariff changes to establish a winter reliability program for winters 2015-2016, 2016-2017 and 2017-2018.[1] One version is advocated by the ISO, the other by NEPOOL. Together, the ISO and NEPOOL join in asking the Commission to choose between these two alternatives. Both the ISO and NEPOOL request that the Commission issue an order in this proceeding by Monday, September 14, 2015 (*i.e.*, within 61 days from the date of this filing).

The ISO and NEPOOL proposals are being submitted pursuant to Section 11.1.5 of the Participants Agreement (referred to as the "jump ball provision").[2] Section 11.1.5 requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission cannot adopt another

[1] Capitalized terms used but not defined in this cover letter are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

[2] *See* Participants Agreement § 11.1.5, *available at* http://nepool.com/uploads/Op-PA.pdf.

proposal not supported by either the ISO or NEPOOL unless it concludes first that neither of those two proposals satisfies the standard for acceptance under the Federal Power Act.[3]

Both proposals are intended to address the well-documented reliability challenges created by New England's increased reliance on natural gas-fueled generation. Both are also intended to be stop-gap measures until revised incentives for capacity resources become fully effective in 2018.[4]

The primary difference between the two proposals relates to the types of resources that are eligible to receive compensation under the winter reliability program. NEPOOL's proposal is based on the design of last winter's program, with three main components included: (1) compensation for certain oil inventory that remains in New England following the end of each winter period; (2) compensation for unused liquefied natural gas ("LNG") contract volumes; and (3) a supplemental demand response program. The ISO's proposal shares the first two design features of NEPOOL's proposal, but is additionally intended to provide compensation for any generator that is supplied by on-site fuel. Therefore, the ISO's proposal would eliminate the demand response component, and provide compensation not only for fuel oil and LNG, but also for nuclear, hydro, biomass and coal-fired resources. In their respective materials, the ISO and NEPOOL further explain the features of each proposal.

<u>The ISO Materials Submitted for this Filing</u>

The ISO is submitting materials in Attachments I-1a through I-1e that include a transmittal letter explaining the ISO's proposed Tariff changes, the testimony of Andrew G. Gillespie in support of the ISO's proposal, and blacklined and clean Tariff sheets. In its materials, the ISO satisfies the requirements in the jump ball provision by explaining the ISO's reasons for not adopting the NEPOOL proposal and by providing an explanation as to why the ISO's proposal is superior to the NEPOOL proposal.

<u>The NEPOOL Materials Submitted for this Filing</u>

The NEPOOL materials contained in Attachments N-1a through N-1i include: (i) the NEPOOL transmittal letter containing an explanation of the NEPOOL proposal, including a discussion of why the NEPOOL proposal is preferable to the ISO proposal and should be accepted by the Commission; (ii) affidavit of Jeffrey W. Bentz, Director of Analysis, New England States Committee on Electricity; testimony of John Flumerfelt, Director of Government and Regulatory Affairs, Calpine Corporation; testimony of Alan A. Trotta, Director of Wholesale Power Contracts, UIL Holdings Corporation; affidavit of Brian E. Forshaw, Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative; and affidavit of Herb Healy, Senior Director of Regulatory Affairs, EnerNOC, Inc., all prepared for NEPOOL; (iii) the

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[3] *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995).

[4] The "Pay-for-Performance" incentive mechanism of the Forward Capacity Market ("FCM") begins to take effect on June 1, 2018.

tabulation of the votes taken by the Participants Committee at its June 25, 2015 meeting with respect to the NEPOOL and ISO proposals; and (iv) blacklined and clean tariff changes reflecting the NEPOOL proposal.

Following this letter is a Table of Contents listing each attachment to this filing.

Respectfully submitted,

ISO NEW ENGLAND INC.

By:____________________________

Maria Gulluni
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
(413) 540-4473
mgulluni@iso-ne.com

Its Attorney

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE

By:_______________________________

David T. Doot
Joseph H. Fagan
Sebastian M. Lombardi
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
(860) 275-0102
(202) 218-3903
dtdoot@daypitney.com
jfagan@daypitney.com
slombardi@daypitney.com

Its Attorneys

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Attachment I-1a

ISO-New England Inc. Filing Letter

July 15, 2015

VIA ELECTRONIC FILING

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ISO New England Inc. and New England Power Pool Filings of Winter Reliability Programs Docket No. ER15-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act[1] and Section 11.1.5 of the Participants Agreement,[2] ISO New England Inc. (the "ISO" or "ISO-NE") hereby submits this transmittal letter and revisions to the Tariff to establish a program to maintain reliability during winters 2015-2016, 2016-2017 and 2017-2018 (the "ISO-NE Proposed Winter Program"). The testimony of Andrew G. Gillespie, Principal Analyst in the Market Development Department at the ISO (the "Gillespie Testimony"), is submitted in support of the ISO-NE Proposed Winter Program.

The ISO-NE Proposed Winter Program follows two prior discrete winter reliability programs. Like last year's program, it offsets generators' carrying costs for unused firm fuel, thereby creating an incentive for generators to secure fuel at the beginning of the winter. Last winter, this structure was critical to ensuring reliability, especially on days when the gas pipelines were constrained.[3]

While the ISO and NEPOOL concur that a winter reliability program is necessary for the next few winters, and agree on many of the design features, they do not agree on the types of resources that should be eligible to participate in the program. Specifically, NEPOOL supports a

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[1] 16 U.S.C. § 824d (2014).

[2] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

[3] http://www.iso-ne.com/static-assets/documents/2015/06/winter_2014_15_review.pdf.

program that, like last year's program, is open to demand resources, oil-fired generators and generators that operate on LNG (the "NEPOOL Proposed Winter Program"). The ISO-NE Proposed Winter Program, on the other hand, is open to any resource capable of running on on-site stored fuel.

Because NEPOOL's vote on the NEPOOL Proposed Winter Program met the applicable threshold, the ISO and NEPOOL are each submitting a proposal pursuant to the "jump ball" process set forth in Section 11.1.5 of the Participants Agreement. As further discussed in Section II of this transmittal letter, the "jump ball" process requires the Commission to consider both proposals and to adopt any or all of the ISO proposal or the NEPOOL proposal "as it finds, in its discretion, to be just and reasonable and preferable." As fully explained in Section IV of this transmittal letter and in the supporting Gillespie Testimony, the ISO believes that its proposal is preferable because it compensates all resource types that provide fuel assurance.

I. DESCRIPTION OF THE ISO; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

Correspondence and communications regarding this filing should be addressed to the undersigned for the ISO as follows:

Maria Gulluni*
Deputy General Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4473
Fax: (413) 535-4379
E-mail: mgulluni@iso-ne.com

*Designated for service.

II. STANDARD OF REVIEW

The Tariff changes included herein and with NEPOOL's transmittal letter are submitted pursuant to the ISO's rights under Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[4] Section 11.1.5 of the Participants Agreement (referred to as the "jump ball provision") requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior.

Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[5] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[6] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[7] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[8] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the Section 205 filing if it is just and reasonable.[9] This standard of review applies to both the ISO proposal and the NEPOOL proposal in terms of evaluating any other alternatives.

As discussed in the joint cover letter submitted by the ISO and NEPOOL, as between the ISO-NE Proposed Winter Program and the NEPOOL Proposed Winter Program, the Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission cannot adopt another proposal not supported by either the ISO or NEPOOL unless it concludes first that neither of those two proposals satisfies the standard summarized above for acceptance under the Federal Power Act.

III. BACKGROUND

In this section, the ISO outlines the impetus for and impact of previous winter programs, and the debate over the structure of future winter programs.

A. Previous Winter Programs

Within the past five years, the ISO and stakeholders have identified and addressed New England's increased reliance on natural gas-fueled generation and deteriorating resource

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[4] *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

[5] *Id.* at 10 (*quoting City of Winnfield v. FERC,* 744 F.2d 871, 876 (D.C. Cir. 1984)).

[6] *Id.* at 9.

[7] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

[8] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[9] *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (*citing Bethany*)).

performance during periods of stressed system conditions.[10] The means of addressing these concerns include various market rule changes, including, most critically, Tariff changes to implement Pay For Performance ("PFP") in the Forward Capacity Market.[11] Effective in 2018, these changes are designed to ensure resource adequacy in a cost-effective manner and reverse the deterioration in reliability.

While work on PFP was underway, it became evident that the region needed to take more immediate action to maintain winter reliability. Specifically, operations during winter 2012-2013 were troubling. Although the winter had been mild, there were a number of instances in which gas-fired generation did not have sufficient fuel to provide energy at or even near the generators' stated capacity, and oil-fired units did not have sufficient fuel to allow for reliable operation during extended and/or repeated periods of cold weather.[12] As a result, the ISO proposed the first winter program, which paid generators upfront for a portion of the costs of having oil in their tanks during the winter of 2013-2014 and also included the procurement of additional demand response.[13] The program proved to be critical to reliability, with generators burning almost all of the program oil in their tanks.[14]

The ISO had not anticipated offering a second program for winter 2014-2015, intending instead to rely on market improvements and the Commission's clarification that generators have an obligation to procure fuel to meet their expected dispatch.[15] However, worse-than-anticipated gas constraints, the retirements of Vermont Yankee and Salem Harbor, difficulties in replenishing oil inventories, and gaps in generator obligations caused ISO-NE to reconsider.[16]

ISO-NE and NEPOOL filed the second program in July 2014.[17] In light of previous market improvements and the Commission's order regarding generator obligations, the program was modified from the first version such that generators were paid only for unused fuel at the

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[10] For background on gas dependence and resource performance, *see* Testimony of Peter T. Brandien in ISO New England Inc., Performance Incentive Market Rule Changes, Docket No. ER14-1050-000 (January 17, 2014).

[11] *See* the Commission's order approving PFP at *ISO New England Inc.,* 147 FERC ¶ 61,172 (2014).

[12] Winter Operations Summary: January –February 2013, http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb__27_draft_for_discussion.pdf.

[13] ISO New England Inc., Winter 2013-14 Reliability Program, Docket No. ER13-1851-000 (June 28, 2013); ISO New England Inc., Emergency Amendments to Pending Filing Regarding the Winter 2013-14 Reliability Program (August 9, 2013).

[14] *See* Testimony of Peter Brandien in ISO New England Inc., Docket No. ER14-2407-000, Winter 2014-2015 Reliability Program Part 1 of 2 at p. 4 (July 11, 2014).

[15] *See* the Commission's order regarding generator obligations at *New England Power Generators Assn., Inc. v. ISO New England Inc.* 144 FERC ¶ 61,157 (August 7, 2013).

[16] ISO New England Inc., Docket No. ER14-2407-000, Winter 2014-2015 Reliability Program Part 1 of 2 (the "Second Winter Program Filing") at p. 4 (July 11, 2014).

[17] *Id.*

end of the season, rather than upfront for fuel procurement. The ISO also maintained the provisions for demand resources and added provisions for LNG in order to improve the program's resource-neutrality. The program was again instrumental in allowing the region to withstand the recent severe weather conditions.[18]

B. Need for and Structure of Future Winter Programs

In the Second Winter Program Filing, the ISO indicated that system conditions had changed such that future winter programs would be necessary in each of the winters before the PFP rules became effective.[19] This need was borne out by ICF International, which updated its 2013 New England natural gas study and reduced projections of available gas during winter 2014-15 by about 500 MMcf/d.[20] ICF concluded that winter peak day gas supplies will be barely adequate or slightly in deficit through 2020, *as long as there are no major contingencies*, such as an outage to gas supplies, loss of electrical sales to New England from the north due to extreme weather, or a nuclear unit tripping offline.[21]

Following the ISO's statements about the need for future programs, the New England Power Generators Association asked the Commission to clarify that such programs must be market-based.[22] The Commission granted this request and directed the ISO to "determine whether a winter reliability solution is necessary for the 2015-2016 winter and future winters, and, if so, develop an appropriate market-based solution through the stakeholder process that can be implemented beginning with the 2015-2016 winter."[23]

The ISO then filed a Request for Rehearing, explaining that, given the context of existing obligations, a market-based program would be, at best, potentially less effective than the winter reliability programs, and, at worst, less effective, inefficient, controversial and expensive to implement.[24] The ISO explained that the inefficiency would stem from the imposition of a new obligation on top of the current framework of existing obligations and the compensation for meeting those obligations. Moreover, the development of a new, broad market would be controversial, resource-intensive and expensive, as was the development of the PFP rules. Finally, in contrast to the proven results of the winter programs, the resulting market may not produce the desired reliability results if participation is too limited, the exemptions too

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[18] http://www.iso-ne.com/static-assets/documents/2015/06/winter_2014_15_review.pdf.

[19] Second Winter Program Filing at pp. 5-6 (July 11, 2014).

[20] *See* ICF's presentation to the Planning Advisory Committee at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a3_icf_benchmarking_study.pdf.

[21] *Id.* at p. 19.

[22] Motion for Clarification of the New England Power Generators Association, Inc., Docket No. ER14-2407-000 (October 9, 2014).

[23] *ISO New England Inc.*, 150 FERC ¶ 61,029 (2015) at p. 10.

[24] Rehearing Request of ISO New England Inc., Docket No. ER14-2407-000 at p. 2 (February 19, 2015).

numerous, or the incentives and penalties too few. The ISO explained that, for all of these reasons, it had abandoned plans for a "PFP-lite" market for the winters before PFP became effective.[25]

The ISO proposed that, instead of developing a market, it would maintain the structure of the prior winter's program, in which generators are paid only for unused fuel at the end of the season. The narrow objective would still be to compensate generators for adopting the ISO's, rather than their own, estimates about how much fuel is needed at the beginning of the winter. However, to improve resource neutrality, the ISO committed to work with stakeholders to expand the winter program to include payments to all resources that can supply the region with fuel assurance. This expansion would more closely resemble a market-based solution through its availability to a majority of resources, while meeting the objective of ensuring fuel adequacy in a targeted, efficient, time-limited manner.[26]

The Commission granted ISO-NE's request, stating,

> [A]n expanded version of the current winter program might better produce the desired results in terms of reliability than the introduction, at this point in time, of the market-based solutions examined by ISO-NE. Thus, we grant rehearing to allow the possibility that ISO-NE may file additional out-of-market winter reliability programs until the two-settlement capacity market design becomes effective in 2018. However, the Commission expects ISO-NE to abide by its commitment to work with stakeholders to expand any future out-of-market winter reliability program to include "all resources that can supply the region with fuel assurance," such as nuclear, coal, and hydro resources.[27]

IV. THE ISO-NE PROPOSED WINTER PROGRAM

The ISO-NE Proposed Winter Program reflects the Commission's order allowing the ISO to file an out-of-market program, as well as the Commission's requirement that the ISO work to expand the program. Accordingly, the ISO-NE Proposed Winter Program is a single program that contributes to reliability in each of the next three winters by compensating resources that have on-site fuel available to support their winter operations. As with last year's program, participating resources may be oil- or LNG-fired. In addition, consistent with its commitment and the Commission's order, ISO-NE proposes participation by any other assets that are supplied by on-site fuel, including uranium, coal, biomass, and water, as these resources' contribution to reliability is also valuable.

Below, ISO-NE describes the program in more detail, contrasts it with the NEPOOL Proposed Winter Program, and evaluates the costs of each.

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[25] *Id.* at pp. 9-11.

[26] *Id.* at pp. 12-13.

[27] *Order Granting Rehearing*, 151 FERC ¶ 61,052 at ¶ 17 (2015).

A. Structure of the ISO-NE Proposed Winter Program

Like last year's program, the ISO-NE Proposed Winter Program is open to oil- and LNG-fired resources, and the rules for these resources are nearly identical to the rules from last year. The ISO-NE Proposed Winter Program differs materially from last year's program largely due to its inclusion of resources with additional types of stored on-site fuel. The rules for participation by each of these resource types are described below.

1. Participation by Oil-Fired Resources

Pursuant to this component of the program, which is contained in Section III.K.2 of the rules, generators must have a minimum level of oil at the beginning of the winter to be eligible to receive an end-of-season payment to offset the costs of unused oil inventory. By offsetting some (but not necessarily all) carrying costs of the unused oil, this compensation is intended to encourage generators to rely on upfront inventory rather than replenishment and to ensure that there is sufficient oil in tanks to meet the region's needs in a cold winter.

The rules for oil-fired unit participation are the same as last year's rules, with limited changes. As was the case last year, to participate in this component of the program, a Market Participant must notify the ISO by October 1 and include an estimate of its expected level of oil inventory on December 1.[28] On December 1, that inventory must meet or exceed the lesser of (i) 85% of usable fuel storage capability and (ii) supply sufficient to operate the generator for ten days at full load.[29] This minimum inventory level, which is designed to exceed generators' historic pre-winter inventory levels, ensures that program dollars pay for inventory that is incremental to the oil that generators would have purchased absent the program.

Oil-fired generators' obligations also remain the same in this iteration of the winter program; participants may not sell their fuel and must offer into the day-ahead and real-time markets.[30] In compensation for meeting their obligations, at the end of the winter, program participants will receive a payment based on the lesser of their December 1 and March 15 inventory, subject to a cap that is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the generator for ten days at full load.[31] The resulting inventory level is multiplied by the rate established by the ISO and then by a performance adjustment factor. That factor is calculated as the number of hours in which the generator was fully or partially available or in which there was a transmission outage rendering them fully unavailable, divided by the total number of winter hours.

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[28] Section III.K.2(b).

[29] *Id.* As they did last year, generators will have a grace period until January 1 to reach their targets, although they will be compensated based on the oil in inventory on December 1.

[30] Section III.K.1(c) and (d).

[31] Section III.K.2(c). As was the case last year, the March 15 inventory excludes any oil added after March 1.

The foregoing payment methodology is the same as last year's, with changes to reduce last year's fifteen-day cap to ten days, and to establish an annual methodology to set the payment rate. Regarding the former, the cap was reduced given the inclusion of additional resource types. The reduction in the cap will affect a small minority of participants, and is not expected to materially impact participation.[32]

The change to establish an annual payment rate reflects the three-year length of the program.[33] The establishment of a rate annually (as opposed to a single three-year rate) will allow the ISO to reflect current market conditions, and will protect against over- or under-paying to meet the ISO's fuel inventory objective. To calculate the rate, the ISO will use the methodology developed for the 2014-2015 program, the goal of which was to offset most, but not necessarily all, costs of holding unused inventory at a level sufficient to meet the ISO's inventory goals.[34] The Gillespie Testimony includes detail on the ISO's calculation of the annual rate.

The resource auditing and performance monitoring rules remain the same. Participants are required to report their fuel inventory levels, and must allow the ISO to audit fuel supplies as requested.[35] Monitoring will continue through November 30 for any oil that is added after February 1, to ensure that such oil is not resold. If it is determined to have been resold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.[36]

Finally, the cost allocation, settlement and financial assurance rules also remain the same.[37] As determined by the Commission regarding the first winter program, costs are allocated to Real-Time Network Load.[38] Compensation will occur after the ISO collects these costs, with any defaults socialized among program participants, as opposed to all Market Participants.

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[32] Gillespie Testimony at p. 6.

[33] Section III.K.1(g).

[34] Regarding the calculation of last year's compensation rate, *see* "Further Explanation of Rate Calculations" by Analysis Group at p. 3 (May 28, 2014) at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun32014/a02a_analysis_group_memo_05_28_14.pdf. The rate for the 2014-15 program was $18/bbl.

[35] Section III.K.6 ("Resource Auditing and Performance Monitoring").

[36] Section III.K.2(c).

[37] Section III.K.7 ("Settlements, Cost Allocation and Financial Assurance").

[38] *See* the Commission's order regarding cost allocation at *ISO New England Inc.*, 144 FERC 61,204 at P 70 (2013).

2. Participation by LNG-Fired Resources

Pursuant to this component of the program, which is contained in Section III.K.3 of the rules, generators that contract for LNG will receive an end-of-season payment to offset the risk of unused contract volumes. This portion of the ISO-NE Proposed Winter Program is unchanged from the LNG component of last year's winter program.

To participate in this component of the program, a Market Participant must notify the ISO by October 1 and describe the contract for which the Market Participant proposes to receive compensation.[39] The ISO will provisionally accept, on a "first come/first served basis," contracts up to the aggregate cap of 6 Bcf.[40]

As a next step, generators must submit their executed contracts to the ISO by December 1. At that time, the generators must also submit a certificate, the form of which is attached to the rules, that confirms, among other things, that the contract has a "take or pay" construct.[41] A "take or pay" construct is most comparable to the unused oil inventory component, in that most of the costs are related to the unused volumes rather than total contract quantities. Other constructs, such as options, have variable terms, including strike price, commodity cost (floating versus fixed), demand/reservation charges, and varying number of calls per contract, all of which create difficulty in understanding what is being delivered. In addition, constructs other than "take or pay" often reflect financial, rather than physical, transactions.

The December 1 certificate also requires the participant to specify the volume and term of the contract, the pipeline delivery point and the gas meter number, and to confirm that the contract includes pipeline transportation to the generator's meter.[42] There is no required minimum, unlike with the unused oil inventory program, because some generators require small amounts of LNG (e.g., for overnight starts only) and because the reliability need for New England can be met through the unused oil program alone.

As set out in Section III.K.3(d), a generator will be compensated at the end of the winter based on the lesser of December 1 and March 1 contract volumes, not to exceed the amount of fuel necessary to permit the generator to operate for four days at full load. The generators' payments will be reduced by a performance adjustment that is the same as the adjustment for oil resources.

The rate at which generators will be compensated will be based on the oil rate established by the ISO in the prior July.[43] Specifically, the compensation rate will be converted from the

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[39] Sections III.K.1(e) and III.K.3(b).

[40] Section III.K.3(b).

[41] Section III.K.3(c) and Attachment 1.

[42] *Id.*

[43] Section III.K.1(g).

rate for oil units, as it was last year. The conversion will be based on a fuel oil heat content of 6.0 MMBtu per barrel.[44]

The resource auditing, performance monitoring, cost allocation and financial assurance rules are the same as those for oil resources and are described in the preceding section.

3. Participation by "Other Resources"

ISO-NE has added a new Section III.K.4 to Appendix K for "Other Stored Fuels." The section is based on Section III.K.2 regarding oil-fired generators, and includes the same provisions regarding the minimum necessary fuel inventory required to participate, the compensation methodology, the cap on compensation, and the performance adjustment. The resource auditing, performance monitoring, cost allocation and financial assurance rules are also the same as for oil and LNG resources. In fact, the only material difference between Sections III.K.2 and III.K.4 is that oil is measured in bbl, while the fuel inventory for "other resources" is converted to equivalent energy (MWh).

4. Other Participation Changes

Last year's program also established a demand response component, which has been eliminated in the ISO-NE Proposed Winter Program due to the incompatibility of demand response with the Program's fuel assurance objective. On the other hand, last year's rules for dual fuel commissioning have been retained in Section III.K.5; while the date for establishing program eligibility has passed (and therefore no new dual fuel resources will be accepted under the program), the rules include a number of outstanding obligations for program participants.

B. Costs of ISO-NE Proposed Winter Program

The costs of the ISO-NE Proposed Winter Program are based on two factors: the amount of participation and the rate of compensation. The first factor, amount of participation, is established through the minimum and maximum participation levels set out in the rules. For oil and gas, the determination of need underlying these levels is consistent with that established for the prior two program iterations.

For the first winter program, the ISO established participation levels for oil resources by calculating the amount of oil that the region could need during a colder winter. The ISO utilized temperatures from winter 2003-04, which had the coldest weather in the last ten years.[45] The ISO concluded that New England would need about 2.4 million MWh from oil-fired generation,

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[44] *Id.*

[45] ISO New England Inc. Winter 2013-14 Reliability Program, Docket No. ER13-1851-000 at p. 6. (June 28, 2013). *See also* the ISO's Winter 2013-2014 Energy Needs Assessment (agenda item A2) that was presented to the April 17, 2013 joint meeting of the NEPOOL Markets and Reliability Committees at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr172013/index.html.

or 4.2 million barrels of oil, to meet the electric demand during a winter with temperatures like those experienced in 2003-04.[46]

For the second winter program, the ISO again used the 4.2 million barrel metric for oil, and added potential participation by the equivalent of 1 million barrels of LNG.[47] Although higher than the previous year, the combined maximum participation was still not sufficient to meet the fleet's needs in the event of 2003-04 weather conditions. That need would amount to 5.8 to 8.2 million barrels of oil, depending on how many MWh were attributed to retiring units.[48]

Given the design of the ISO-NE Proposed Winter Program, the maximum participation is roughly the same for oil and LNG as it was last year. In addition, as discussed more fully in the Gillespie Testimony, the "other resources" category can be expected to attract participation of the equivalent of 2.7 million barrels of oil.

The second component in calculating cost is the rate of compensation. That rate will be established in July, and is likely, for this winter, to be lower than last year's rate of $18, given current market conditions. Assuming a rate of $13, the program costs for oil and gas will be $66.3 million, *if no fuel is used*. If fuel is used in proportion to last year's usage, actual program costs for oil and gas would be approximately $36.4 million.[49]

Using the $13 rate, the costs for adding additional resource types are – at the high end – $35.1 million. Again, this estimate assumes that no fuel is used.[50]

C. Comparison with the NEPOOL Proposed Winter Program

In sum, the ISO and NEPOOL agree on the need for a winter program and the inclusion of oil- and LNG-fired resources within that program; in fact, the proposals are identical with respect to those two resource types. The difference between the proposals relates to the inclusion of other types of resources, and the related costs. Specifically, ISO-NE has included other resources that are supplied by on-site fuel, while NEPOOL would exclude them. The programs also differ regarding demand response; while NEPOOL would include it, ISO-NE would exclude it as outside the program's objective of ensuring fuel adequacy.[51] The resulting cost differential renders the ISO-NE Proposed Winter Program more expensive by an estimated maximum of $35.1 million, depending on fuel usage and demand response participation.

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[46] *Id.*

[47] Second Winter Program Filing at pp. 11-12.

[48] *Id.*

[49] *See* the Chief Operating Officer's April 2015 report at p. 8 for oil usage during the 2014-15 winter. The report is located at http://www.iso-ne.com/static-assets/documents/2015/04/npc_20150410_addl.pdf .

[50] *See* the Gillespie Testimony at pp. 17-18.

[51] The demand response component of last year's winter program attracted three participants totaling 14 MW.

ISO-NE believes that the ISO-NE Proposed Winter Program is preferable to the NEPOOL Proposed Winter Program because, by including all resources that can supply the fuel assurance service, it better approximates the results of a market-based construct, and is non-discriminatory because all resources that have the requisite on-site fuel are compensated for their contribution to reliability. Moreover, the inclusion of these resources should provide value to the region, in that the expectation of a three-year revenue stream may cause these generators to invest in additional fuel inventory and in the asset more generally.

V. STAKEHOLDER PROCESS

The ISO and stakeholders began discussing reliability solutions for future winters at the November 13, 2014 NEPOOL Markets Committee meeting and continued to do so on a monthly basis,[52] culminating in the Markets Committee's June 2, 2015 vote on both the ISO-NE Proposed Winter Program and the NEPOOL Proposed Winter Program. The Markets Committee, with a vote of 84.51% in favor, recommended that the NEPOOL Participants Committee support the NEPOOL Proposed Winter Program. The ISO-NE Proposed Winter Program failed to obtain a recommendation from the Markets Committee, with a vote of 19.36% in favor. Following the Markets Committee's consideration of both proposals, the matter was then presented to the NEPOOL Participants Committee for its consideration.

At its June 25, 2015 meeting, the NEPOOL Participants Committee considered both proposals. With a vote of 87.10% in favor, the NEPOOL Participants Committee supported the NEPOOL Proposed Winter Program. The NEPOOL Participants Committee failed to support the ISO-NE Proposed Winter Program with a 13.43% vote in favor. Further details concerning the results of the stakeholder process are provided in NEPOOL's transmittal letter and associated materials.

VI. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the ISO-NE Proposed Winter Program as filed, without suspension or hearing, to be effective on September 14, 2015.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[53] However, the ISO-NE Proposed Winter Program is not a traditional "rate," and the ISO is not a traditional investor-owned utility. In light of these circumstances, the ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13, and

[52] For more information on the stakeholder process, *see* the informational filings made by ISO-NE in Docket No. ER14-2407-000, including most recently the "Informational Filing Related to the 2014-2015 Winter Reliability Program" (June 8, 2015).

[53] 18 C.F.R. § 35.13.

requests a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

35.13(b)(1) - Materials included herewith are as follows:

- This transmittal letter;
- Tariff Section III.K;
- Redlined Tariff Section III.K;
- the Gillespie Testimony; and
- A list of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities to which a copy of this filing has been sent.

35.13(b)(2) - The ISO requests that the revisions become effective on September 14, 2015.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/participate/participant-asset-listings/directory. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this Section VII.

35.13(b)(5) - The reasons for this filing are discussed in Section IV of this transmittal letter.

35.13(b)(6) - The ISO's approval of the revisions is evidenced by this filing. The Participants Processes were completed as discussed in Section V of this transmittal letter.

35.13(b)(7) - The ISO does not have knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

35.13(c)(1) – The market rule change herein does not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the wholesale, resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions filed herein.

VIII. CONCLUSION

For the reasons stated herein and in the accompanying testimony, the ISO respectfully requests that the Commission determine that the ISO-NE Proposed Winter Program is preferable to the NEPOOL Proposed Winter Program, and that it accept the ISO's Tariff changes as filed, to become effective on September 14, 2015.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: */s/ Maria Gulluni*
Maria Gulluni
Deputy General Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
(413) 535-4000

Attachment I-1b

Testimony of Andrew Gillespie

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER15-___-000**

TESTIMONY OF
ANDREW G. GILLESPIE
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: My name is Andrew G. Gillespie. I am a Principal Analyst in the Market Development Department at ISO New England Inc. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A: I have a Bachelor of Science degree in Mechanical Engineering from Northeastern University, a Masters of Business Administration degree from Emory University, and I am a registered Professional Engineer in Massachusetts. I have over twenty years of energy industry experience, including power plant engineering and performance monitoring, asset management, and emissions and energy trading. I worked in the ISO's market monitoring group from 2005 to 2008. In 2008, I joined the ISO's Market Development Department as a Principal Analyst, with responsibilities for developing improvements in the electricity markets and drafting market rules and manuals to implement those improvements.

Q: WHAT IS THE PURPOSE AND ORGANIZATION OF YOUR TESTIMONY?

A: My testimony is intended to provide background on the development of the program that the ISO has proposed to address concerns about reliability in the upcoming winters (the "ISO-NE Proposed Winter Program"), including each of its component parts. I also discuss the potential costs of the ISO-NE Proposed Winter Program.

II. <u>TESTIMONY</u>

A. <u>OVERVIEW OF THE PROGRAM</u>

Q: WHAT ISSUES ARE ADDRESSED BY THE ISO-NE PROPOSED WINTER PROGRAM AND WHAT IS THE LONG-TERM PLAN TO ADDRESS THESE ISSUES?

A: Within the past five years, the region has observed increased dependence on natural gas-fueled generation and the deteriorating performance of generators during periods of stressed system conditions.[1] To address these problems in the long term, the ISO proposed, and the Commission approved, changes to the incentive structure in the Forward Capacity Market to strengthen the incentives for all generators to make adequate fuel arrangements and provide the region with the required operating flexibility, particularly under stressed power system conditions.[2] These market rules are known as "Pay For Performance" or "PFP").

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[1] For background on gas dependence and resource performance, *see* Testimony of Peter T. Brandien in ISO New England Inc., Performance Incentive Market Rule Changes, Docket No. ER14-1050-000 (January 17, 2014).

[2] *ISO New England Inc.*, 147 FERC 61,172 (2014).

The ISO believes that, once Pay For Performance is in place, it will eliminate the need for supplemental winter programs. However, until that time – June of 2018 – the ISO believes that winter programs will be necessary.

Q: WHY ISN'T THE ISO OFFERING A MARKET-BASED SOLUTION?

A: As the ISO pointed out in filings on this topic in last year's winter docket, a market-based program would be inefficient given the imposition of a new obligation on top of the current framework of existing obligations.[3] Moreover, the development of a new, broad market would be controversial, as was the development of the PFP rules. Finally, in contrast to the proven results of the winter programs, the resulting market may not produce the desired reliability results if participation is too limited, the exemptions too numerous, or the incentives and penalties too few. For all of these reasons, the ISO abandoned plans for a "PFP-lite" market for the winters before PFP became effective.

Q: PLEASE PROVIDE AN OVERVIEW OF THE ISO-NE PROPOSED WINTER PROGRAM.

A: The program covers the three winters before the PFP rules are effective, with a compensation rate being set (and communicated to stakeholders) in the summer before each winter. This compensation rate, like last year, will compensate generators for some, but not all, of the carrying costs of unused oil.

Like last year, the program is open to oil- and LNG-fired generators. In addition, the ISO has added a similar component for other resource types that are able to

[3] *See* Rehearing Request of ISO New England Inc., Docket No. ER14-2407-000 (February 19, 2015).

operate on stored fuel. These rules are contained in Section III.K of the Tariff.

Q: HOW IS THE WINTER RELIABILITY PROGRAM DIFFERENT THAN LAST YEAR'S WINTER PROGRAM?

A: The program differs primarily in the resource types that are included and the length of the program. Regarding resource types, the ISO has proposed the inclusion of additional types of resources that are able to store fuel onsite, including, for example, coal-fired, nuclear and hydro resources. The ISO has also proposed the exclusion of last year's demand response component, as it is incompatible with the program's focus on fuel assurance.

The duration of this program is also different. The prior two programs were each for a single winter. The program that is proposed here would be the same for each of the next three winters, with only the resources participating and the compensation rate changing in each winter.

The rules for the two components that are the same as last year – oil and LNG – are nearly identical to last year's rules, with one change to the oil component rules to reduce the cap on compensation from fifteen to ten days of oil inventory. This change is discussed below.

Q: IS THE RATE OF COMPENSATION THE SAME OVER THE THREE YEAR PROGRAM PERIOD?

A: No. The program requires the establishment of a rate annually (as opposed to a single three-year rate). Annual rate-setting allows the ISO to reflect current market conditions to keep the rate relevant for participation each winter.

Q: HOW WILL THE ISO SET THE RATE?

A: To calculate the rate, the ISO will use the methodology developed for the 2014-2015 program, the goal of which was to offset most, but not necessarily all, costs of holding unused inventory at a level sufficient to meet the ISO's inventory goals. The components of the rate are discussed further below.

B. OVERVIEW OF OIL COMPONENT

Q: PLEASE DESCRIBE THE OIL COMPONENT OF THE WINTER RELIABILITY PROGRAM.

A: To participate, generators must have a minimum level of oil at the beginning of the winter to be eligible to receive an end-of-season payment to offset the costs of unused oil inventory. This compensation is intended to encourage generators to rely on upfront inventory rather than replenishment and to ensure that there is sufficient oil in on-site inventory to meet the region's needs in a cold winter.

Q: HOW DO GENERATORS INDICATE THEIR INTEREST IN PARTICIPATING?

A: Pursuant to Section III.K.2 of the rules, to participate, a Market Participant must notify the ISO by October 1 before each winter and include an estimate of its expected level of oil inventory on December 1.

Q: HOW MUCH OIL IS THE ISO TARGETING FROM THE REGION AND EACH GENERATOR?

A: On December 1, a participating generator's oil inventory must meet or exceed the lesser of (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the generator for 10 days at full load. The ISO will include oil burned after November 15 in this inventory, as well as oil used for audits (although the latter must be returned to inventory).[4] The maximum inventory that is eligible for compensation at the end of each winter for a generator is the lesser of (i) 95% of the usable fuel storage capability and (ii) supply sufficient to operate the generator for 10 days at full load.[5] These targets, in the aggregate, exceed the oil inventory levels that have traditionally been achieved, thereby ensuring that program dollars pay for inventory that is incremental to the oil that generators would have purchased absent the program.

Q: ARE THESE MINIMUM AND MAXIMUM INVENTORY LEVELS THE SAME AS LAST YEAR?

A: The minimum levels are the same. The maximum level has been reduced from a fifteen-day cap in last year's program to a ten-day cap. The cap was reduced given the inclusion of additional resource types. The reduction in the cap will affect a small minority of participants, and is not expected to materially impact participation.

Q: WHAT HAPPENS IF GENERATORS CAN'T REACH THE THRESHOLD INVENTORY LEVELS BY DECEMBER 1?

A: Generators will have a grace period until January 1 to reach their targets, although they will be compensated based on the oil in inventory on December 1.[6] If

[4] III.K.2(b).

[5] III.K.2(c).

[6] III.K.2(b).

generators fail to meet the minimum by January 1, they will not be eligible for the end-of-season payment.

Q: CAN GENERATORS SHARE OIL IN A COMMON TANK?

A: Yes, provided that all generators with a shared fuel supply must participate.[7] This requirement ensures that the supply is not diluted across the generators sharing the tank, and that the oil is incremental. In the event that a generator using a shared tank is expected to be out of service for the winter period, the ISO has the ability to make an exception to the requirement.[8]

Q: WHAT OBLIGATIONS DO THESE GENERATORS HAVE?

A: Participating generators must submit Supply Offers into the Day-Ahead Energy Market and Real-Time Energy Market at their physical capacity for each hour of the day. They are also prohibited from selling program oil during the winter.[9]

Q: HOW WILL UNITS PROVIDING THE SERVICE BE COMPENSATED?

A: As set out in Section III.K.2(c), generators will be compensated at the end of the winter based on the formula (Eligible Inventory x Set Rate) x Performance Adjustment. These payments are in addition to payments pursuant to the Tariff for Energy, Ancillary Services or other services, none of which are varied by the ISO-NE Proposed Winter Program.

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[7] III.K.1(f).

[8] *Id.*

[9] III.K.1(c) and III.K.1(d).

Q: HOW IS ELIGIBLE INVENTORY DETERMINED?

A: The "Eligible Inventory" portion of the payment formula is the lesser of (i) the inventory on December 1 (calculated as set out in Section III.K.2(b)); (ii) the maximum described above; and (iii) the inventory on March 15, which excludes any oil added after March 1.

Q: WHY IS OIL ADDED AFTER MARCH 1 EXCLUDED?

A: Excluding oil added after March 1, but measuring the inventory on March 15, may reduce the cost of this portion of the ISO-NE Proposed Winter Program in the amount of the fuel used to operate the plant in the first half of March, and provides some cost protection to load if resources elect to replenish towards the end of the winter.

Q: WHAT PREVENTS GENERATORS FROM REFILLING THEIR TANKS TO INCREASE THEIR PAYMENTS?

A: Participants can fill their tanks back to their December 1 levels to maximize compensation, assuming that the logistics of the scheduling fuel deliveries makes this possible for a facility; however, they must use this oil for energy production. As explained in Section III.K.2(c), fuel delivered after February 1 that is subsequently sold will cause the participant's compensation to be recalculated to exclude that fuel. To make this determination, the ISO will monitor through November 30 the inventory levels of participants that added oil after February 1.

Q: HOW IS THE SET RATE DETERMINED?

A: The set rate will be determined in dollars per barrel before each winter. Like last year, it will offset some, but not necessarily all, costs of holding unused inventory at a level sufficient to meet the ISO's inventory goals. As other incentives, including inframarginal returns and generator obligations, exist, it is not necessary to compensate generators for 100% of these costs.[10]

In determining the rate, the ISO will quantify and then sum three types of costs: carrying costs, which are the opportunity cost of dollars invested in securing oil inventory over the time period that inventory is held; price risk, which is the risk that prices decrease subsequent to the purchase of oil inventory; and liquidity risk, which is the risk that the value of stored oil not used by the end of the winter season cannot be easily liquidated.

To calculate carrying costs, the ISO will multiply a forecast of the following October's fuel price by the three-month Treasury Rate. For price risk, the ISO will determine the premium for a twelve-month put option. Finally, the liquidity risk cost will be determined by multiplying next October's fuel price by a percentage representing the implied risk premium on the after-tax weighted average cost of capital.[11]

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[10] For more information on how the rate was set last year, *see* 2014/2015 Winter Program: Program Rates, Limits and Potential Costs by Analysis Group (June 6, 2014) at A03 of http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun10112014/index.html.

[11] After July 15, *see* www.iso-ne.com/markets-operations/markets/winter-program-payment-rate for the memorandum outlining the calculation of the rate for the 2015-16 winter.

Q: PLEASE DESCRIBE THE PERFORMANCE ADJUSTMENT.

A: The performance adjustment is simply the number of hours in which the generator was fully or partially available or in which there was a transmission outage making the resource fully unavailable, divided by the total number of winter hours. In essence, this adjustment results in generators losing a pro rata portion of their payment when they are fully unavailable and could otherwise have used some of the fuel that remains in inventory at the end of the winter.

Q: ARE THERE ANY OTHER PENALTIES?

A: No.

Q: HOW WILL THE ISO MONITOR OIL USE?

A: As set out in Section III.K.6, participating generators must report their usable oil inventory levels to the ISO on the first of the month during the winter and as otherwise requested. Moreover, Section III.K.6 requires participants to maintain detailed fuel logs and to provide the logs, fuel inventory levels and other relevant documentation, including receipts, to the ISO upon request. Participants must also allow ISO staff or designees on-site to verify reported fuel levels.

C. OVERVIEW OF LNG COMPONENT

Q: PLEASE DESCRIBE THIS COMPONENT OF THE WINTER RELIABILITY PROGRAM.

A: Pursuant to this component of the program, which is contained in Section III.K.3 of the rules, generators that contract for LNG will receive an end-of-season payment to offset the risk of unused contract volumes. This portion of the ISO-

NE Proposed Winter Program is intended to create incentives for generators to acquire LNG as a peaking fuel and to augment the use of pipeline gas.

Q: HOW DO GENERATORS INDICATE THEIR INTEREST IN PARTICIPATING?

A: Pursuant to Section III.K.1(e) of the rules, to participate in this component of the program, a Market Participant must notify the ISO by October 1. Pursuant to Section III.K.3(b), this notice must describe the contract for which the Market Participant proposes to receive compensation. The ISO will provisionally accept, on a "first come/first served basis," contracts up to (i) the aggregate cap of 6 Bcf and (ii) the daily output of LNG providers. The ISO will provide notice of this provisional acceptance by October 15.

Q: DO GENERATORS SUBMIT THEIR EXECUTED CONTRACTS?

A: As set out in Section III.K.3(c), generators must submit the executed contracts to the ISO by December 1. The generators must also submit a certificate, the form of which is attached to the rules, that confirms that the contract has a "take or pay" construct, specifies the volume and term of the contract, includes the pipeline delivery point and gas meter number, and confirms that the contract includes pipeline transportation to the generator's meter.

Q: WHY MUST THE CONTRACT HAVE A "TAKE OR PAY" CONSTRUCT?

A: A "take or pay" construct is most comparable to the unused oil inventory component of the ISO-NE Proposed Winter Program, in that most of the costs are related to the unused volumes rather than total contract quantities. Other constructs, such as options, have variable terms, including strike price, commodity cost (floating versus fixed), demand/reservation charges, and varying number of calls per contract, all of which create difficulty in understanding what is being delivered. In addition, constructs other than "take or pay" can often reflect financial, rather than physical, transactions.

Q: HOW MUCH LNG IS THE ISO TARGETING FROM THE REGION AND EACH GENERATOR?

A: The ISO has not established a minimum amount of LNG in part because some generators may require small amounts of LNG (e.g., for overnight starts only). To set the maximum amounts, the ISO included both a per-generator and total program cap. Specifically, each generator will be compensated up to the amount needed to operate at full load for four days. Across the entire fleet, the maximum amount of LNG for compensation is 6 Bcf. These are the same thresholds that were used last year. At that time, they were calculated considering the region's needs for fuel in a cold winter, the amount that could reasonably be used as a peaking product, and the latest ICF International analyses of LNG flows, including the capacity flow limits on the Algonquin and Tennessee pipelines.[12]

Q: WHAT OBLIGATIONS DO THESE GENERATORS HAVE?

A: Participating generators must submit Supply Offers into the Day-Ahead Energy Market and Real-Time Energy Market at their physical capacity for each hour of

[12] ISO New England Inc., Docket No. ER14-2407-000, Winter 2014-2015 Reliability Program Part 1 of 2 at p. 12 (July 11, 2014).

the day. They are also prohibited from selling their LNG or rights thereto during the winter.[13]

Q: HOW WILL UNITS PROVIDING THE SERVICE BE COMPENSATED?

A: As set out in Section III.K.3(d), generators will be compensated at the end of the winter based on the formula (Unused Quantity x Set Rate) x Performance Adjustment. These payments are in addition to payments pursuant to the Tariff for Energy, Ancillary Services or other services, none of which are varied by the ISO-NE Proposed Winter Program.

Q: HOW IS UNUSED QUANTITY DETERMINED?

A: The "Unused Quantity" portion of the payment formula is the lesser of December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the generator to operate for four days at full load.

Q: HOW IS THE SET RATE DETERMINED?

A: The set rate is converted from the oil rate (which is in barrels) to an MMBtu rate using an oil-to-energy conversion factor. This is the same methodology that was used last year.[14] Specifically, the conversion uses New England's average heat content for oil, which is 6.0 MMBtu/bbl. The equation is LNG Rate = R_0 x (1 / H_{avg}) (\$/MMBtu), where R_0 is the set rate for oil (\$/bbl) and H_{avg} is the 6.0 average heat content of fuel oil.

[13] III.K.1(c) and III.K.1(d).

[14] 2014/2015 Winter Program: Program Rates, Limits and Potential Costs by Analysis Group (June 6, 2014) at 11; at A03 of http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun10112014/index.html.

Q: PLEASE DESCRIBE THE PERFORMANCE ADJUSTMENT.

A: As with the unused oil inventory portion of the ISO-NE Proposed Winter Program, the performance adjustment is simply the number of hours in which the generator was fully or partially available or in which there was a transmission outage rendering them fully unavailable, divided by the total number of winter hours.

Q: ARE THERE ANY OTHER PENALTIES?

A: No.

Q: HOW WILL THE ISO MONITOR LNG USE?

A: As for oil-fired generators, Section III.K.6 requires participating generators to report their remaining contracted volumes to the ISO on the first of the month during the winter and as otherwise requested. Moreover, Section III.K.6 requires participants to maintain detailed fuel logs and to provide the logs, fuel inventory levels and other relevant documentation, including receipts, to the ISO upon request.

D. <u>OVERVIEW OF "OTHER STORED FUELS" COMPONENT</u>

Q: WHY WAS THIS COMPONENT ADDED TO THE PROGRAM?

A: By including all resources that can supply the fuel assurance service, it better approximates the results of a market-based construct, and is non-discriminatory because all resources that have the requisite on-site fuel are compensated for their contribution to reliability.

Q: WHAT TYPES OF RESOURCES MIGHT PARTICIPATE?

A: Any assets that are supplied by on-site fuel may participate. These would include, for example, nuclear units (fueled by uranium), coal-fired units, biomass resources, and units fueled by water, including pumped storage resources.

Q: PLEASE DESCRIBE THIS COMPONENT OF THE WINTER RELIABILITY PROGRAM.

A: This component of the program uses the same structure as the oil component. Accordingly, the rules are the same, except that fuel is measured in MWh, and the set rate is converted into MWh (discussed below).[15]

Q: HOW WILL UNITS PROVIDING THE SERVICE BE COMPENSATED?

A: As with oil, generators will be compensated at the end of the winter based on the formula (Eligible Inventory x Set Rate) x Performance Adjustment. The "Eligible Inventory" portion of the payment formula is the lesser of (i) the inventory on December 1 (calculated as set out in Section III.K.4(b)); (ii) the maximum inventory that is eligible for compensation (lesser of 95% of the usable fuel storage capability and supply sufficient to operate the generator for 10 days at full load); and (iii) the inventory on March 15, which excludes any fuel added after March 1. The Performance Adjustment is the same as that for oil- and LNG-fired resources.[16]

[15] III.K.4.

[16] III.K.4(c).

Q: HOW IS THE SET RATE DETERMINED?

A: The set rate is converted from the oil rate (which is in barrels) to a MWh rate using the New England average heat content for oil and a generic heat rate. The equation is: Other Stored Fuel Rate = R_0 x (HR_g / H_{avg}), where R_0 is the set rate for oil ($/bbl), HR_g is the generic heat rate of 10 MMBtu/MWh, and H_{avg} is the 6.0 average heat content of fuel oil.

E. <u>OTHER COMPONENTS OF APPENDIX K</u>

Q: WHAT OTHER RULES ARE INCLUDED IN APPENDIX K?

A: There are two sections that are the same as last year. Specifically, last year's rules for dual fuel commissioning have been retained in Section III.K.5. Although the date for establishing program eligibility has passed, the rules include a number of outstanding obligations for program participants. Also, Section III.K.7 includes the rules regarding settlements, cost allocation and financial assurance, all of which are the same as those approved by the Commission for last year's program.

Q: DOES APPENDIX K DIFFER IN OTHER WAYS FROM LAST YEAR?

A: Last year's program included a demand response component, which has been eliminated in the ISO-NE Proposed Winter Program due to the incompatibility of demand response with the Program's fuel assurance objective.

F. PROGRAM COSTS

Q: HOW WILL PROGRAM COSTS BE DETERMINED?

A: The costs of the ISO-NE Proposed Winter Program are based on two factors: the amount of participation and the rate of compensation.

Q: WHAT IS THE EXPECTED RATE OF PARTICIPATION?

A: The amount of participation is established through the minimum and maximum participation levels set out in the rules. If the program were to be fully subscribed, participation for each eligible resource type would be as shown in the table below.

Type	Total MW (SCC)	Equivalent Barrels (Mil.)
Nuclear	4,041	1.62 [1]
Coal	2,002	0.80 [1]
Biomass	577	0.23 [2]
Hydro (pondage)	2,941	0.05 [3]
Oil (inc. dual-fuel)	10,778	4.10 [4]
LNG	[6 BCF]	1.00 [5]
	21,839	7.8

1) Equivalent barrels based on 10 days operation at winter SCC (6.0 MMBtu/bbl)
2) Wood/wood waste resources only
3) Estimated storage capability
4) The same participation level as observed in the 2014-15 Winter Program
5) Maximum eligible amount (6 BCF)

Q: DOES THIS RATE OF PARTICIPATION EXCEED THE REGION'S NEED?

A: No. The fuel need has been calculated with reference to the amount of oil that the region could need during a colder winter like that of winter 2003-04. As determined last year, the fleet's needs in the event of 2003-04 weather conditions amount to 5.8 to 8.2 million barrels of oil, depending on how many MWh are attributed to retired units.

Q: WHAT IS THE EXPECTED RATE OF COMPENSATION?

A: That rate will be established by July 15 of each year, and is likely, for this winter, to be lower than last year's rate of $18, given current market conditions.

Q: CAN YOU PROVIDE A PROGRAM COST ESTIMATE?

A: Assuming a rate of $13, the program costs for oil and gas will be $66.3 million, *if no fuel is used*. If fuel is used in proportion to last year's usage, actual program costs for oil and gas would be approximately $36.4 million. Using the $13 rate, the costs for adding additional resource types are – at the high end – $35.1 million. Again, this estimate assumes that no fuel is used. In sum, given a rate of $13, my high-end estimate is that total program costs would be $101.4 million.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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

Executed on July 15, 2015.

Andrew G. Gillespie

Attachment I-1c

ISO-NE Marked Tariff Sheets

APPENDIX K

WINTER RELIABILITY SOLUTIONS

WINTER RELIABILITY SOLUTIONS

III.K.1. **General~~Purpose and Sunset~~.**

(a) **Term.** The~~is~~ ~~ISO is providing incentives for the four services described in this~~ Appendix K is intended to ~~n order to~~ mitigate potential fuel-related system reliability issues within New England during the ~~winter season. The services are: (a) establishment of oil inventory by Generator Assets prior to December 1, (b) establishment of liquefied natural gas contracts by Generator Assets prior to December 1, (c) commissioning of dual-fuel capability by Generator Assets on or before December 1, 2016, and (d) additional reductions in demand and/or provision of net supply by demand response assets during the winter~~2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.

(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; be modeled in the EMS; and either (i) be dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.

(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.

(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.

(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.

(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 through III.K.4 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Nothwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.

(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas and other fuels.

Conflict. ~~.~~

~~This Appendix K sets out a process for Market Participants to provide one or more of these services, and the terms and conditions on which the services must be provided.~~

(h) Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.

~~Unless extended, this Appendix K, other than Section III.K.5, shall expire on March 15, 2015, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein. Section III.K.5 shall expire on December 1, 2016.~~

~~**III.K.2. Eligibility and General Requirements.**~~

~~Only Market Participants may provide the services described in this Appendix K. Participating Generator Assets must be modeled in the EMS and dispatchable as described in Operating Procedure #14. Regardless of whether they have a Capacity Supply Obligation, Market Participants providing services under Sections III.K.3 and III.K.4 must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum~~

~~Limit for each hour of the Operating Day during the winter. Market Participants may not sell the fuel (or fuel rights) described in Sections III.K.3 through III.K.5 during the period in which they are obligated (which extends through and including the winter of 2017 for Generator Assets providing the dual fuel service described in Section III.K.5), or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K. To participate in one or more of the services, a Market Participant must notify the ISO by October 1 (or, in the case of the dual fuel commissioning service described in Section III.K.5, December 1, 2014) and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset.~~

III.K.2. Oil Fuel.

Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety-fill and structural limitations. Tanks removed from service due to structural damage or for long-~~-~~term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.

~~III.K.3. Oil Fuel Service.~~

~~Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.~~

(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil. ~~Generator Assets that share a fuel supply may participate only if all Generator Assets sharing the fuel supply participate, in which case the oil inventory levels described below will be calculated in the aggregate; provided that the ISO may exempt one or more Generator Assets from the requirement that all Generator Assets sharing a fuel supply must participate if the ISO determines at the beginning of the winter period that the Generator Asset(s) are reasonably expected to be out of service for the winter period.~~

(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.~~2~~1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1~~.~~ of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.~~3~~2(d). The December 1 inventory level will be deemed to include~~: (x)~~ oil that the ISO determines was burned to produce electricity on and after November 15~~; and (y) a credit for oil~~ of that ~~was burned in~~year, including during an audit of dual fuel capability ~~occurring on or after November 15~~, provided that ~~the~~ oil used in ~~the~~an audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.~~3~~2.

~~(c) **Measuring Inventory.** Participating Generator Assets must report their usable oil inventory levels to the ISO on the first of the month during the winter and as otherwise requested by the ISO.~~

~~(d)~~(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K.~~3~~2(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for ~~15~~10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. ~~Set Rate shall mean $18/barrel.~~ Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.~~4~~3. Liquefied Natural Gas ~~Service~~.

Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of th~~e~~at winter.

(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving ~~both~~ pipeline gas ~~and~~ or supplies of liquefied natural gas.

(b) **Proposed Contracts.** In the notice specified in Section III.K.~~2~~1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.~~4~~3. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.~~4~~3(c). The ISO will review the notices and ~~provide notice~~inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.~~4~~3(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a "first come/first served" basis and shall inform Generator Assets of their provisional acceptance by each October 15.

(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a "take-or-pay" construct; the volume specified by the Market Participant pursuant to Section III.K.~~4~~3(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO's provisional acceptance will be withdrawn.

~~(d) **Measuring Use.** Participating Generator Assets must report their remaining contracted volumes to the ISO on the first of the month during the winter and as otherwise requested by the ISO, and provide other supporting documentation as required.~~

~~(e)~~(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:

(Unused Quantity x Set Rate) x Performance Adjustment

Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. ~~The Set Rate shall mean \$3.00/MMBTU.~~ Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

III.K.~~5~~4. Other Stored Fuels.

Pursuant to this service, Market Participants with Generator Assets that are supplied by on-site fuel will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

(a) **Eligibility.** Generator Assets are eligible for compensation based on the levels of on-site fuel storage used by the Generator Assets to produce electricity. Examples include uranium, coal, biomass feedstock and water (weekly cycle or pumped storage), provided that, to receive compensation hereunder, the water must stored in the impoundment that is created by the Generator Asset's dam, within the Commission's approved limits (i.e., water that is available from upstream impoundments is not eligible).

(b) **December 1 Fuel Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of fuel inventory (in terms of equivalent energy, MWh, that the resource could produce from that amount) on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable fuel inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.4(d). The December 1 inventory level will be deemed to include fuel that the ISO determines was burned to produce electricity on and after November 15 of that year.

(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K.4(b) and converted to equivalent energy (MWh). Maximum December 1 Inventory is the lesser of the equivalent energy (MWh) produced by (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the equivalent energy (MWh) that could be produced by the usable fuel inventory on March 15, excluding any fuel that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1.

Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

The March 15 Inventory shall be adjusted for any Market Participant that added fuel inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the fuel inventory levels of those Generator Assets that added fuel inventory after February 1. If the ISO determines that any fuel is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.5 Dual Fuel Commissioning Service.

As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual fuel capability.

(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.

(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the compensation for which the Market Participant is eligible if it achieves dual fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.

(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset: (i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.

(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.1.5.2(e)(iii) and Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.

(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November 15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. ~~Generator Assets must report their usable oil inventory levels to the ISO on the first of the month during the winter and as otherwise requested by the ISO.~~ Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.

(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(e) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(e) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage ~~on May 31, 2018~~, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).

(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:

Monthly Compensation x the number of months between date of the breach and May 31, 2018

Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.

III.K.6 ~~Demand Response Service.~~

~~All defined terms used in this Section III.K.6 shall have the same meanings as if the asset were a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.~~

~~Market Participants with an asset located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including an asset with~~

~~behind-the-meter generation capable of reducing demand from the electric system and delivering any net supply, are eligible to participate pursuant to this Appendix K. Assets mapped to a Real-Time Demand Response Resource are eligible to participate, subject to the additional requirements specified below, and provided that the capacity supplied by these assets is in addition to the Capacity Supply Obligation, as of December 1 of the relevant Capacity Commitment Period, of the Real-Time Demand Response Resource to which the asset is mapped, and provided further that the prohibitions in Section III.E1.1.2 are not triggered.~~

~~Except for assets mapped to a Real-Time Demand Response Resource, an asset may consist of an aggregation of individual end-use facilities so long as those facilities are located within the same Dispatch Zone, and provided further that such aggregation does not result in a quantity of demand reduction and net supply of 5 MW or greater at a single Node.~~

~~The following asset types are not eligible to provide services under this Section III.K.5: (i) Real-Time Emergency Generation Assets; (ii) any asset that is dependent upon a non-firm or an additional supply of natural gas to produce demand reductions or net supply; and (iii) any asset that participates in the energy market pursuant to Section III.1 of the Tariff.~~

~~Each Market Participant that has an asset accepted by the ISO for this service is subject to the following additional requirements from December 1 through March 1:~~

~~(a) **In service.** By December 1, participating assets must, in accordance with the existing requirements for Real-Time Demand Response Assets and Real-Time Emergency Generation Assets: (i) be registered with the ISO; (ii) have meters installed and operational; (iii) have a valid Demand Response Baseline; (iv) have a Demand Designated Entity to which Dispatch Instructions are communicated; and (v) otherwise be fully ready to respond.~~

~~(b) **Size of Program and Assets.** Each participating asset shall provide at least 100 kW of capability. No more than 100 assets at a level not to exceed 100 MW shall be accepted by the ISO pursuant to this Appendix K.~~

~~(c) **Metering.**~~

~~i. Market Participants must meet the metering requirements specified in Appendix III.E and the ISO New England manuals, with the exception that 5-minute meter data does not have to be reported to the ISO in real time for assets not mapped to a Real-Time Demand Response Resource.~~

ii. ~~To the extent that an asset consists of an aggregation of individual end-use facilities, Market Participants must submit a single set of interval meter data, as measured from each facility's Retail Delivery Point, representing the sum of the metered demand of the end-use facilities comprising the asset.~~

iii. ~~Market Participants shall report meter data and may submit meter data corrections to the ISO using the Demand Response Market User Interface within 2.5 business days after the Operating Day.~~

iv. ~~Meter data corrections may be submitted during the 70-day period beginning with the first of the month following the operating month. To the extent meter data affecting an asset's performance measurement and passing all quality checks has not been submitted by the initial settlement deadline (i.e., within 2.5 business days after the Operating Day), payments related to that asset shall be deferred to the resettlement process.~~

v. ~~In the event that valid meter data affecting an asset's monthly performance measurement that passes all quality checks is not submitted by the end of the 70-day data correction limit, that asset's performance shall be deemed to be zero for the intervals for which the meter data did not pass all quality checks.~~

~~(d)~~ **~~Dispatch.~~**

i. ~~Assets must be available for dispatch in real time between hours ending 0600 and 2300 on all days.~~

ii. ~~Each dispatch shall be for no more than six hours.~~

iii. ~~There will be no more than two dispatches per asset per day.~~

iv. ~~There shall be at least four hours between the end of one dispatch and the start time of another dispatch.~~

v. ~~Assets will be dispatched by the ISO at its discretion prior to, or concurrent with, ISO New England Operating Procedure No. 4, Action 2. The ISO may aggregate assets into blocks and dispatch only those assets comprising the blocks.~~

vi. ~~Each asset shall be required to respond to Dispatch Instructions no more than thirty times.~~

vii. ~~The ISO will communicate Dispatch Instructions to the Demand Designated Entity specified by the Market Participant for each participating asset.~~

viii. ~~Assets will be dispatched for their entire, committed MW quantity except in cases where such dispatch may cause or worsen a local reliability problem. The ISO may, upon notification to the Demand Designated Entity, exclude from dispatch assets located in a particular Dispatch Zone, and/or individual assets where the committed MW quantity is 5 MW or more.~~

ix. ~~Except as outlined in viii. above, assets must produce the MW quantity accepted pursuant to this Appendix K within thirty minutes of the issuance of a Dispatch Instruction.~~

x. ~~If assets mapped to a Real-Time Demand Response Resource are dispatched pursuant to this Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource, and the amount of demand reduction plus any net supply produced in that interval is less than the Real-Time Demand Response Resource's Capacity Supply Obligation plus the sum of the asset's committed MW quantity pursuant to Appendix K, the amount of demand reduction plus any net supply produced shall be credited first to the Real-Time Demand Response Resource's Capacity Supply Obligation and the remainder shall be credited pro-rata to each asset with an obligation pursuant to Appendix K based on asset performance.~~

(e) ~~**Acceptance Criteria.** Market Participants must indicate their commitment to provide this demand response service by providing the notice indicated in Section III.K.2. That notice must include: the name and other pertinent identifiers of the asset that the Market Participant is seeking to enroll, the asset's electrical location, the MW quantity of demand reduction and any net supply, as measured from the asset's Retail Delivery Point, that the asset is willing and able to produce in response to Dispatch Instructions, and the method(s) by which the demand reduction or any net supply would be produced. If the Market Participant has not yet identified all of the assets that will be recruited to meet the service requirements, the Market Participant shall provide a description of how it will meet the requirements, and provide the Dispatch Zone within which these assets will be located. If an asset specified in the notice consists of an aggregation of individual end-use facilities, the information shall be provided for each facility that is part of the aggregation. The ISO shall accept up to 100 qualified assets at a level not to exceed 100 MW from those Market Participants providing notice, based on:~~

i. ~~The asset's proposed capacity;~~

~~ii. The asset's location relative to known constrained areas; and/or~~

~~iii. Any historic performance from the asset.~~

~~The ISO may accept or reject any and all assets proposed for participation.~~

~~(f) **Compensation.**~~

~~i. **Monthly Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** Market Participants providing the demand response services described herein shall be compensated under this Appendix K through a monthly payment of $1,800 multiplied by the average MW performance achieved by the asset in the month, provided that such MW performance shall not exceed 150% of the committed MW quantity. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If the asset was not dispatched or audited in the month of December, the payment for that asset for that month will be based on its average MW performance in response to dispatch (including a dispatch for an audit) in the following month. If an asset was not dispatched in January or February, but was dispatched or audited in a previous month, the asset's payment for the month in which it was not dispatched will be based on its average MW performance in the most recent month in which the asset was dispatched or audited.~~

~~ii. **Monthly Payment for Assets Mapped to a Real-Time Demand Response Resource.** The monthly payment for assets that are mapped to a Real-Time Demand Response Resource will be $1,800 multiplied by the average MW performance achieved by the asset in the month not to exceed 100% of the committed MW quantity, and further multiplied by the Performance Factor. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If an asset is dispatched in a month pursuant to Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource to which it is mapped, a Performance Factor will be calculated as follows:~~

~~*Performance Factor = (Average Hourly FCM Performance – Average Hourly Dispatch MW)*~~

~~*Winter Obligation MW*~~

~~Average Hourly FCM Performance is the average hourly MW reduction amount (inclusive of any net supply) achieved during the month by the Real-Time Demand Response Resource to which the asset is mapped during dispatch or audit pursuant to Section III.13. Average Hourly Dispatch MW is the average hourly MW reduction amount (inclusive of any net supply) in the Dispatch Instructions issued during the month pursuant to Section III.13 to the Real-Time Demand Response Resource to which the asset is mapped, which would not exceed the resource's Capacity Supply Obligation. Winter Obligation MW is the committed quantity of the asset pursuant to Appendix K in MW. The Performance Factor shall not exceed 1.0. The Performance Factor for a month will apply to monthly payments in subsequent months during the term if, in those subsequent months, the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13. If the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13 in the month of December, an audit of the resource will be conducted in the month of January. The audit shall assess the resource's ability to meet its Capacity Supply Obligation plus the sum of the committed quantity pursuant to Appendix K for assets mapped to the resource. The Performance Factor calculated during this audit will be applied to the month of December.~~

~~iii.~~ **~~Energy Payment for Assets Not Mapped to a Real-Time Demand Response Resource.~~** ~~Market Participants providing the demand response services described herein shall also receive a monthly energy payment, as follows:~~

~~Winter DR Program Energy Payment =~~

~~(MAX ($250/MWh, Zonal LMP) x MWh Delivered x 1.065) – E Payment~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time and where the 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program~~

~~located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~iv. **Energy Payment for Assets Mapped to a Real-Time Demand Response Resource.** During hours in which an asset is dispatched concurrently with the hours in which it receives a demand curtailment schedule or initiates a Real-Time demand reduction pursuant to Section III.E or with the dispatch of the Real-Time Demand Response Resource to which the asset is mapped, the Energy payment received by the asset pursuant to Section III.E or Section III.13.7.2.5.3 will be subtracted from the energy payment hereunder. The energy payment for these assets will be computed as follows:~~

~~*Winter DR Program Energy Payment =*~~

~~*MAX [(MAX ($250/MWh, Zonal LMP) x MWh Delivered) x 1.065 –*~~

~~*TDR Payment– E Payment, 0]*~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time. TDR Payment is the Energy payment received by the asset pursuant to Section III.13.7.2.5.3 or Section III.E. The 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~v. **Voluntary Performance.** If the ISO dispatches an asset more than thirty times, the asset's response to those dispatches is voluntary, and any performance by the asset in~~

~~response to those dispatches would not be used to calculate the monthly payment for services under this Appendix K or to assess non-performance. However, any Energy provided by the asset in response to these dispatches would be compensated as described in the preceding paragraphs.~~

~~(g) **Non-Performance Charges.** The non-performance charges for assets providing the demand response services described in this Section III.K.6 shall be:~~

~~i. For failure to reach 75% performance: If the asset fails to achieve an average MW performance of at least 75% of the committed MW quantity in a month, the asset shall forfeit its monthly payment for that month and for any other month during the term for which such performance is utilized for settlement.~~

~~ii. For failure to submit valid meter data: the provisions of Section III.K.6(c)(v) shall apply with regard to meter data deemed to be zero because of quality problems.~~

~~III.K.7~~. Resource Auditing and Performance Monitoring.

Participating Generator Assets must report their usable oil inventory levels, remaining contracted liquefied natural gas volumes, or other fuel inventory levels to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also ~~providing the service described in Section III.K.3 through III.K.5 shall~~ maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.

~~Market Participants providing the demand response service described in Section III.K.6 shall be audited by the ISO in the month of January if the asset was not dispatched or audited prior to the scheduled audit. During the audit, the ISO shall dispatch the asset without prior notice and assess its performance during the sixty minutes immediately following the end of the thirty-minute notification time. The results of an audit will be treated and settled as though it were a dispatch to maintain thirty-minute Operating Reserve. Audits of assets mapped to Real-Time Demand Response Resources will be concurrent with audits of those resources. If a Real-Time Demand Response Resource with a Capacity Supply Obligation is dispatched or audited, the performance of any assets providing demand response service pursuant to this~~

~~Appendix K that are mapped to that resource shall be excluded from the performance of the resource if the audit is used as a Demand Resource Commercial Operation Audit. The performance of assets dispatched or audited pursuant to this Appendix K shall be equal to the difference between the asset's adjusted Demand Response Baseline, determined pursuant to Section III.8, and the asset's meter reading during the period of dispatch (after consideration of the thirty-minute notification time). For purposes of establishing, computing, and adjusting an asset's Demand Response Baseline, assets dispatched or audited pursuant to this Appendix K shall be treated like a dispatch or audit pursuant to Section III.13.~~

III.K.~~8~~7. Settlements, Cost Allocation and Financial Assurance.

~~(a)~~ **Cost Allocation and Settlement~~, by Service~~.**

~~i.~~ . Compensation to Market Participants for ~~the oil and liquefied natural gas~~ services described in ~~Sections III.~~Sections III.K.2 through III.K.4~~K.3 and III.K.4~~ shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Payments shall be made to the Market Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected.

~~(b) The monthly compensation described in Section III.K.6(f)(i)-(ii) for the demand response services described in Section III.K.6 shall be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the compensation is earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). The hourly compensation described in Section III.K.6(f)(iii)-(iv) shall be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation for the hour in which the service was provided, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Payments shall be made to the Market~~

~~Participants providing the services through the ISO's settlements system in the month after the ISO makes the collections referenced in the first two sentences of this paragraph.~~

~~(c)~~(a) Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.

~~(d)~~(b) **Allocation and Settlement of Non-Performance Charges.** All repayments required herein~~pursuant to Sections III.K.3 and III.K.5~~, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only).

~~(e)~~(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to ~~Sections III.~~this Appendix K~~.3 or III.K.5~~ shall result in a reduced refund pursuant to Section III.K.~~8~~7(b) to Real-Time Load Obligation.

APPENDIX K, ATTACHMENT 1

CONTRACT CERTIFICATION

The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:

1. Contracting parties:____
2. Date of contract:____
3. Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:____
4. Maximum total volume available under the contract:______________________________

~~5.~~ Contract term (date and years) (must span, at a minimum, December 1 through the end of February):________

5. ____

6. Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]
7. Any contract terms that restrict when the supply may be taken by the Generator Asset:

   ____
8. Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]
9. Entity providing pipeline transportation: ____________________________________
10. Confirmation that contract has a "take or pay" construct: [Confirmed]

[MARKET PARTICIPANT]

By:__________________
Name:
Title:

Date:

Attachment I-1d

ISO-NE Clean Tariff Sheet

APPENDIX K

WINTER RELIABILITY SOLUTIONS

WINTER RELIABILITY SOLUTIONS

III.K.1. General.

(a) **Term.** This Appendix K is intended to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.

(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; be modeled in the EMS; and either (i) be dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.

(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.

(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.

(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.

(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 through III.K.4 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Nothwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.

(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas and other fuels.

(h) **Conflict.** Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.

III.K.2. Oil Fuel.

Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety-fill and structural limitations. Tanks removed from service due to structural damage or for long-term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.

(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil.

(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.2(d). The December 1 inventory level will be deemed to include oil that the ISO determines was burned to produce electricity on and after November 15 of that year, including during an audit of dual fuel capability, provided that oil used in an audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.2.

(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K.2(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.3. Liquefied Natural Gas.

Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of that winter.

(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving pipeline gas or supplies of liquefied natural gas.

(b) **Proposed Contracts.** In the notice specified in Section III.K.1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.3. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.3(c). The ISO will review the notices and inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.3(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a “first come/first served” basis and shall inform Generator Assets of their provisional acceptance by each October 15.

(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a “take-or-pay” construct; the volume specified by the Market Participant pursuant to Section III.K.3(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO’s provisional acceptance will be withdrawn.

(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:

(Unused Quantity x Set Rate) x Performance Adjustment

Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

III.K.4. Other Stored Fuels.

Pursuant to this service, Market Participants with Generator Assets that are supplied by on-site fuel will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

(a) **Eligibility.** Generator Assets are eligible for compensation based on the levels of on-site fuel storage used by the Generator Assets to produce electricity. Examples include uranium, coal, biomass feedstock and water (weekly cycle or pumped storage), provided that, to receive compensation hereunder, the water must stored in the impoundment that is created by the Generator Asset's dam, within the Commission's approved limits (i.e., water that is available from upstream impoundments is not eligible).

(b) **December 1 Fuel Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of fuel inventory (in terms of equivalent energy, MWh, that the resource could produce from that amount) on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable fuel inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.4(d). The December 1 inventory level will be deemed to include fuel that the ISO determines was burned to produce electricity on and after November 15 of that year.

(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K.4(b) and converted to equivalent energy (MWh). Maximum December 1 Inventory is the lesser of the equivalent energy (MWh) produced by (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the equivalent energy (MWh) that could be produced by the usable fuel inventory on March 15, excluding any fuel that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. Performance Adjustment shall mean:

$$\frac{\text{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\text{(Total number of winter hours)}}$$

The March 15 Inventory shall be adjusted for any Market Participant that added fuel inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the fuel inventory levels of those Generator Assets that added fuel inventory after February 1. If the ISO determines that any fuel is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.5 Dual Fuel Commissioning Service.

As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual fuel capability.

(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.

(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the compensation for which the Market Participant is eligible if it achieves dual fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.

(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset: (i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.

(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.1.5.2(e)(iii) and Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.

(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November 15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.

(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(e) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(e) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).

(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:

Monthly Compensation x the number of months between date of the breach and May 31, 2018

Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.

III.K.6. Resource Auditing and Performance Monitoring.

Participating Generator Assets must report their usable oil inventory levels, remaining contracted liquefied natural gas volumes, or other fuel inventory levels to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.

III.K.7. Settlements, Cost Allocation and Financial Assurance.

(a) **Cost Allocation and Settlement.** Compensation to Market Participants for services described in Sections III.K.2 through III.K.4 shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Payments shall be made to the Market Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected. Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.

(b) **Allocation and Settlement of Non-Performance Charges.** All repayments required herein, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only).

(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to this Appendix K shall result in a reduced refund pursuant to Section III.K.7(b) to Real-Time Load Obligation.

APPENDIX K, ATTACHMENT 1

CONTRACT CERTIFICATION

The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:

1. Contracting parties:____

2. Date of contract:____

3. Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:____

4. Maximum total volume available under the contract:_____________________________

5. Contract term (date and years) (must span, at a minimum, December 1 through the end of February):____

6. Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]

7. Any contract terms that restrict when the supply may be taken by the Generator Asset:

   ____

8. Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]

9. Entity providing pipeline transportation: ______________________________________

10. Confirmation that contract has a “take or pay” construct: [Confirmed]

[MARKET PARTICIPANT]

By:____________________
Name:
Title:
Date:

Attachment I-1e

List of New England Governors and

Utility Regulatory Agencies

New England Governors, State Utility Regulators and Related Agencies

Connecticut

The Honorable Dannel P. Malloy
Office of the Governor
State Capitol
210 Capitol Ave.
Hartford, CT 06106
Liz.Donohue@ct.gov
Paul.Mounds@ct.gov

mailto:Transition.Team@ct.gov Connecticut
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051-2605
robert.luysterborghs@ct.gov
michael.coyle@ct.gov
clare.kindall@ct.gov

Maine

The Honorable Paul LePage
One State House Station
Office of the Governor
Augusta, ME 04333-0001
Kathleen.Newman@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
Maine.puc@maine.gov

Massachusetts

The Honorable Charles Baker
Office of the Governor
State House
Boston, MA 02133

Massachusetts Attorney General Office
One Ashburton Place
Boston, MA 02108
rebecca.tepper@state.ma.us

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
Nancy.Stevens@state.ma.us
morgane.treanton@state.ma.us

New Hampshire

The Honorable Maggie Hassan
Office of the Governor
26 Capital Street
Concord NH 03301
kerry.mchugh@nh.gov
Meredith.Hatfield@nh.gov

New Hampshire Public Utilities Commission
21 South Fruit Street, Ste. 10
Concord, NH 03301-2429
tom.frantz@puc.nh.gov
george.mccluskey@puc.nh.gov
F.Ross@puc.nh.gov
David.goyette@puc.nh.gov
RegionalEnergy@puc.nh.gov
Robert.scott@puc.nh.gov
amanda.noonan@puc.nh.gov

Rhode Island

The Honorable Gina Raimondo
Office of the Governor
82 Smith Street
Providence, RI 02903
eric.beane@governor.ri.gov
todd.bianco@puc.ri.gov
Marion.Gold@energy.ri.gov
christopher.kearns@energy.ri.gov
Danny.Musher@energy.ri.gov
nicholas.ucci@energy.ri.gov

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
Margaret.curran@puc.ri.gov
paul.roberti@puc.ri.gov
todd.bianco@puc.ri.gov

New England Governors, State Utility Regulators and Related Agencies

Vermont

The Honorable Peter Shumlin
Office of the Governor
109 State Street, Pavilion
Montpelier, VT 05609
Darren.Springer@state.vt.us
Justin.johnson@state.vt.us

Vermont Public Service Board
112 State Street
Montpelier, VT 05620-2701
mary-jo.krolewski@state.vt.us
sarah.d.hofmann@state.vt.us

Vermont Department of Public Service
112 State Street, Drawer 20
Montpelier, VT 05620-2601
bill.jordan@state.vt.us
chris.recchia@state.vt.us
Ed.McNamara@state.vt.us

New England Governors, Utility Regulatory and Related Agencies

Anne Stubbs
Coalition of Northeastern Governors
400 North Capitol Street, NW
Washington, DC 20001
coneg@sso.org

Heather Hunt, Executive Director
New England States Committee on Electricity
655 Longmeadow Street
Longmeadow, MA 01106
HeatherHunt@nescoe.com
JasonMarshall@nescoe.com

Rachel Goldwasser, Executive Director
New England Conference of Public Utilities
Commissioners
Concord, NH 03301
rgoldwasser@necpuc.org

Margaret "Meg" Curran, President
New England Conference of Public Utilities
Commissioners
89 Jefferson Boulevard
Warwick, RI 02888
margaret.curran@puc.ri.gov

Harvey L. Reiter, Esq.
Counsel for New England Conference of Public
Utilities Commissioners, Inc.
c/o Stinson Morrison Hecker LLP
1150 18th Street, N.W., Ste. 800
Washington, DC 20036-3816
HReiter@stinson.com

ATTACHMENT N-1a

Transmittal letter on behalf of NEPOOL

NEW ENGLAND POWER POOL

July 15, 2015

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ISO New England Inc. and New England Power Pool, Docket No. ER15-___-000; *NEPOOL Proposed Revisions to Market Rule 1 of the ISO-NE Tariff to Implement a Winter Reliability Program for Winter Periods Prior to June 1, 2018*

Dear Secretary Bose:

The New England Power Pool ("NEPOOL")[1] Participants Committee[2] hereby submits for inclusion in a joint filing with ISO New England Inc. ("ISO-NE") NEPOOL-approved changes to Market Rule 1, in order to establish a winter reliability program for the winter periods prior to June 1, 2018 (the "NEPOOL Proposal"). The NEPOOL Proposal is designed to maintain the core components of the Commission-approved 2014-2015 Winter Reliability Program ("2014-15 Program") that proved to be successful in helping to maintain reliability during the past winter. NEPOOL's proposed changes to Market Rule 1 are an alternative and preferred set of revisions to Market Rule changes proposed by ISO-NE (the "ISO-NE Proposal"), which are separately described by ISO-NE in its transmittal letter and supporting materials.

[1] NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 440 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and independent transmission company and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, NEPOOL provides the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the ISO-NE Tariff.

[2] Capitalized terms not defined herein have the meanings ascribed thereto in the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO-NE Transmission, Markets and Services Tariff (the "ISO-NE Tariff"). Section III of the Tariff is referred to as "Market Rule 1."

The purpose of both the NEPOOL Proposal and ISO-NE Proposal is to help ensure that reliability is maintained during times of system stress during the winter, which has been caused primarily because of the limited availability of natural gas pipeline capacity to satisfy New England's natural gas needs during cold peak usage months. Over the last several years, the region has instituted Market Rule changes to help address the region's operating concerns. While those changes have helped, the region has concluded that some additional incentive continues to be needed to help ensure reliability during each of the three winter periods from now until the "Pay-for-Performance" (or "PFP") measures of the Forward Capacity Market ("FCM") are fully implemented in June 2018.[3]

Both Proposals modify various provisions of Appendix K to Market Rule 1.[4] The NEPOOL Proposal revives portions of the 2014-15 Program that were previously accepted by the Commission as being just and reasonable, and were successfully deployed by the region for the 2014-15 Winter, but that expired on March 15, 2015.[5] The three main elements of the NEPOOL Proposal are as follows: (1) compensation for certain oil inventory that remains in New England following the end of each winter period; (2) end-of-season compensation for liquefied natural gas ("LNG") contract volumes that were available for use during the winter but were not called upon to produce energy; and (3) a supplemental demand response program. The ISO-NE Proposal shares the first two elements of the NEPOOL proposal. However, it would eliminate the demand response component of the 2014-15 Program, and would expand the program to provide compensation not only for fuel oil and LNG, but for any dispatchable (or self-scheduled) resource that has on-site fuel storage, such as nuclear, coal, biomass and certain hydro resources.

The Proposals also differ in their respective expected costs and stakeholder support. The NEPOOL Proposal secured a strong recommendation of the NEPOOL Markets Committee (with 84.51% recommending Participants Committee approval), that was accepted and approved by a 87.10% Vote of the NEPOOL Participants Committee. By contrast, the ISO-NE Proposal only garnered 19.36% Vote of the NEPOOL Markets Committee to recommend Participants Committee approval, and only 13.43% Vote of the Participants Committee.

These two alternate Proposals are being submitted in a "jump ball" filing. Significantly, from the Commission's perspective, in a "jump ball" filing, the alternate proposals are presented on precisely the same legal footing. Accordingly, the Commission "may adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable."[6] NEPOOL describes in this transmittal letter ("Letter")

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[3] PFP refers to the impending two-settlement capacity market design under which a resource that produces energy or provides reserves during Capacity Scarcity Conditions in excess of a *pro rata* share of its Capacity Supply Obligation would receive additional revenue, while a resource that produces less than its *pro rata* share would face a reduction in its net capacity revenue.

[4] Appendix K to Section III is the Winter Reliability Program.

[5] *See ISO New England Inc. and New England Power Pool*, Winter 2014-2015 Reliability Program under ER14-2407-000, -001 (dated July 11, 2014) (referred to herein as the "July 2014 Filing").

[6] *See* Participants Agreement §11.1.5, *available at*: http://nepool.com/uploads/Op-PA.pdf.

and supporting materials why its Proposal is just and reasonable and preferable to the ISO-NE Proposal. NEPOOL further urges that the Commission accept the NEPOOL Proposal, without suspension or hearing, to be effective Monday, September 14, 2015, which is 61 days from the date of this filing.

In addition to this Letter, NEPOOL also offers the following in support of its Proposal:[7]

- Attachment N-1b -- Testimony of Jeffrey W. Bentz, Director of Analysis, New England States Committee on Electricity ("NESCOE") (the "Bentz Testimony");
- Attachment N-1c -- Testimony of John Flumerfelt, Director of Government and Regulatory Affairs, Calpine Corporation ("Calpine") (the "Flumerfelt Testimony");
- Attachment N-1d -- Testimony of Alan A. Trotta, Director of Wholesale Power Contracts, UIL Holdings Corporation (the "Trotta Testimony");
- Attachment N-1e -- Affidavit of Brian E. Forshaw, Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative ("CMEEC") (the "Forshaw Affidavit");
- Attachment N-1f -- Affidavit of Herb Healy, Senior Director of Regulatory Affairs, EnerNOC, Inc. ("EnerNOC") (the "Healy Affidavit");
- Attachment N-1g -- A tabulation of the NEPOOL votes taken on the NEPOOL and ISO-NE Proposals at the June 23-25, 2015 NEPOOL Participants Committee meeting;
- Attachment N-1h -- Blacklined Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective September 14, 2015; and
- Attachment N-1i -- Clean Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective September 14, 2015.

I. <u>JUMP BALL STANDARD</u>

The governance arrangements negotiated and approved in order for ISO-NE to assume the role of the regional transmission organization in New England provide in Section 11.1.5 of

[7] NEPOOL Participants register their individual positions through votes on NEPOOL matters and, if they wish, through further explanations of their views during the stakeholder process. NEPOOL's positions are defined by the voting results. The affidavits/testimony reflect the views of their respective companies and do not reflect in all instances the positions or opinions of all NEPOOL Participants.

the Participants Agreement for a "jump ball" filing when ISO-NE and NEPOOL approve alternative proposed changes to the Market Rules. Section 11.1.5 requires ISO-NE to make a "jump ball" filing when NEPOOL supports by at least a 60% Vote of the Participants Committee a Market Rule change that is different than what is being proposed by ISO-NE. In a "jump ball" filing, a NEPOOL proposal is filed under Section 205 of the Federal Power Act at the same time and on the same legal footing as an alternative ISO-NE proposal. As noted, the jump ball standard calls on the Commission to decide between two just and reasonable proposals.[8]

Thus, the jump ball provision expands the more limited authority of the Commission that constrains its actions in response to a more traditional filing under Section 205. In a Section 205 filing where ISO-NE and NEPOOL are in agreement, the Commission "plays 'an essentially passive and reactive' role"[9] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[10] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[11] The filed proposal "need not be the only reasonable methodology, or even the most accurate."[12] As a result, in a more typical Section 205 filing, even if an intervenor or the Commission identifies an alternative proposal, the Commission must accept the proposal reflected in the Section 205 filing if it is just and reasonable.[13] Here, however, if the Commission finds both proposals to be just and reasonable, the Commission has the latitude to choose between the NEPOOL and ISO-NE Proposals based on what the Commission views to be preferable, and is not bound to conclude that one proposal is unjust and unreasonable before it

[8] Section 11.1.5 of the Participants Agreement provides in its entirety as follows:

> If the Participants Committee vote relating to an [ISO-NE] Market Rule proposal results in the approval by the Participants Committee by a Participants Vote equal to or greater than 60% of a Market Rule proposal that is different from the one proposed by [ISO-NE], including, but not limited to, a Governance Participant proposal, [ISO-NE] shall, as part of any required Section 205 filing, describe the alternate Market Rule proposal in detail sufficient to permit reasonable review by the Commission, explain [ISO-NE]'s reasons for not adopting the proposal, and provide an explanation as to why [ISO-NE] believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission will not be required to consider whether the then-existing filed rate is unlawful, and may adopt any or all of [ISO-NE]'s Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable.

[9] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[10] *Id.* at 9.

[11] *Cities of Bethany. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

[12] *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[13] *Cf. Southern California Edison Co.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (*citing Cities of Bethany*, 727 F.2d at 1136)).

can consider the second proposal. If there are any additional proposals suggested in pleadings by intervenors though, those proposals cannot be accepted unless the Commission first concludes that neither the NEPOOL Proposal nor the ISO-NE Proposal is just and reasonable.[14]

II. COMMUNICATIONS AND CORRESPONDENCE

Communications and correspondence regarding this proceeding should be sent to the individuals listed below:

Joel S. Gordon
Chair, NEPOOL Participants Committee
PSEG Power Connecticut, LLC
7 Steeple Lane
Amherst. NH 03031
(603) 673-6654
Joel.Gordon@pseg.com

David T. Doot
Joseph H. Fagan
Sebastian M. Lombardi
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
(860) 275-0102
(202) 218-3903
dtdoot@daypitney.com
jfagan@daypitney.com
slombardi@daypitney.com

III. BACKGROUND

As THE stakeholder voting advisory organization on all wholesale market matters in New England,[15] NEPOOL organizationally has worked with ISO-NE and state officials to address market and reliability challenges. Together, NEPOOL and ISO-NE have jointly proposed numerous market enhancements designed to provide stronger economic incentives for resource availability and to help address evolving reliability challenges associated with the region's increasing reliance on natural gas. Those market enhancements have included the following: modifications to the Day-Ahead Energy Market schedule;[16] re-definition of Shortage Event triggers in the FCM;[17] changes to permit bidders increased energy offer flexibility, including the opportunity to make hourly intraday re-offers;[18] changes to the Forward Reserve Market incentives;[19] market mitigation changes to allow dual-fuel units to take better advantage

[14] *Id.*

[15] *See* Participants Agreement § 2.2.

[16] *ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (Apr. 24, 2013).

[17] *See ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (Nov. 1, 2013).

[18] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 (Oct. 3, 2013).

[19] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1733-000 (Aug. 15, 2013) (unpublished letter order accepting revisions concerning Forward Reserve Market incentives).

of fuel switching capability;[20] and expanded authority for ISO-NE to communicate with natural gas pipeline operators.[21] In addition, through a jump ball filing of market reforms to the FCM, the Commission approved NEPOOL-proposed increases to Reserve Constraint Penalty Factor ("RCPF") values and ISO-NE's proposed PFP.[22] While the RCPF changes went into effect on December 3, 2014, the PFP provisions will not be fully effective until June 1, 2018.

The market changes identified above and others have helped in addressing reliability challenges, but the region's experiences during the 2012-13 winter led NEPOOL, ISO-NE and state officials to conclude that supplemental incentives were needed, at least until PFP was fully implemented. Specifically, NEPOOL, ISO-NE and state officials concluded that some supplemental program was needed to provide incentive for incremental fuel to be positioned and available for use in the region when constraints in natural gas pipelines were adversely impacting the availability of natural gas generators in the region or for demand to be reduced.

The first Winter Reliability Program was created for the December 2013 – February 2014 winter period ("2013-14 Program"). The 2013-14 Program was supported by over 85% Vote of NEPOOL and was jointly filed by ISO-NE and NEPOOL.[23] It included four main components: (1) incremental demand response program; (2) oil inventory service; (3) payments to units that were able to produce energy on either natural gas or oil (i.e., dual-fuel units) for ensuring through testing that they could switch to oil when needed; and (4) market monitoring changes aimed at increasing the flexibility and, therefore, revenue potential, of dual-fuel units. Under the 2013-14 Program, ISO-NE issued a request for proposals ("RFP") for incremental demand response and oil inventory. ISO-NE structured that RFP for these components with up-front "pay-as-bid" compensation. The 2013-14 Program resulted in more than three million barrels of oil procured before the winter started and 3,780 MWh of incremental demand response available for the winter.[24] Those incremental resources, which were estimated to cost consumers approximately $75 million,[25] were credited as being instrumental in assuring reliability during the 2013-14 winter and, for that reason, the 2013-14 Program was widely considered a success.

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[20] *ISO New England Inc. and New England Power Pool*, Docket No. ER14-707-000 (Jan. 15, 2014) (unpublished letter order accepting relocation of dual-fuel switching provisions).

[21] *See* Pipeline Information-Sharing Changes, *ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER14-970-000 (filed Jan. 10, 2014).

[22] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014).

[23] *ISO New England Inc. and New England Power Pool*, Winter 2013-14 Reliability Program, Docket No. ER13-1851-000 (June 28, 2013) (the "June 2013 Filing"); *see also* Vote Tabulation from June 27, 2013 Participants Committee meeting included in June 2013 Filing.

[24] *See ISO New England Inc.*, Winter Reliability Bid Results Filing, Docket No. ER13-2266-000 (Aug. 26, 2013).

[25] *See* March 2014 ISO-NE COO Report, *available at*: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/mar72014/coo_report_mar_2014.pdf.

In July of 2014, ISO-NE and NEPOOL jointly filed Tariff revisions to create the 2014-15 Winter Reliability Program ("2014-15 Program"). The 2014-15 Program, which again was broadly supported by NEPOOL, this time with a 90.95% Vote,[26] was designed with the benefit of the experience of the prior winter, including experience with various market enhancements, as well as knowledge of additional market enhancements to become effective for the first time ahead of the upcoming winter. Given that information, the 2014-15 Program created incentives for maintaining increased fuel inventory, dual-fuel resource capability and participation, and a revised incremental demand response component. Unlike the 2013-14 Program however, the 2014-15 Program did not make "as-bid" payments for initial inventories of fuel oil, but instead promised payments to offset certain carrying costs of fuel oil purchased by generators ahead of the winter that was unused at the end of the winter. In addition, the 2014-15 Program recognized the contribution of LNG during the prior winter in supporting winter reliability in the region. The 2014-2015 Program also provided that those who entered into contracts for the winter to back-up their pipeline gas with LNG also could receive incremental compensation for unused LNG entitlements, similar to the compensation paid for unused oil inventory. In the end, the payments under the 2014-15 Program resulted in a total cost of just over $46 million, which was almost 40% less than the cost of the prior winter's program.[27] Like the previous year's winter program though, the 2014-15 Program achieved the desired result, with the region well positioned with fuel inventory at the start of the 2014-15 winter.[28]

IV. NEPOOL PROCESS CONSIDERING THE NEPOOL AND ISO-NE PROPOSALS

The NEPOOL process for exploring proposals to be in effect for the three winters remaining until PFP is fully implemented was heavily influenced by the Commission's guidance to the region. In its order approving the 2014-15 Program on September 9, 2014, the Commission directed ISO-NE to initiate a stakeholder process to "develop a proposal to address reliability concerns for the 2015-2016 winter and future winters, as necessary."[29] In that, and in prior orders, the Commission also identified its preference for a market solution rather than an out-of-market solution.

With this guidance, in November of last year, ISO-NE initiated discussions in the NEPOOL stakeholder process to develop a proposal to address reliability concerns for the 2015-2016 winter and for future winters until PFP implementation. These discussions were informed

[26] *See* Vote Tabulation from June 24-26, 2014 Participants Committee meeting included in the July 2014 Filing.

[27] The 2014-15 Program final costs for the oil, LNG, demand response and dual-fuel commissioning components: oil costs ($43.9M); LNG costs ($1.4M); demand response program ($75.6K); and dual-fuel commissioning program ($1.0M of Net Commitment-Period Compensation ("NCPC") incurred). *See* ISO-NE's Winter 2014/15 Program Review, *available at*: http://www.iso-ne.com/static-assets/documents/2015/04/npc_20150410_addl.pdf, at pp. 5, 8.

[28] ISO-NE Press Release on 2014-15 Program (dated Apr. 7, 2015), *available at*: http://isonewswire.com/updates/2015/4/7/new-england-power-system-performed-well-through-winter-20142.html.

[29] *Order Accepting Tariff Revisions*, 148 FERC ¶ 61,179 (2014) (the "September Order").

by the results of the 2013-14 Program and the unfolding results of the 2014-15 Program. NEPOOL members, ISO-NE and state representatives, worked together to explore numerous potential solutions to winter reliability issues, including whether a new program was warranted in the first place and various market-based concepts.[30]

In December and early January, ISO-NE indicated that if there was no consensus on an interim alternative "market-based" solution, it would propose to use the framework of the 2014-15 Program as an interim solution for future winters (through 2017-2018).[31] During this time, ISO-NE also explained that "the Winter Reliability Program's *objective* is to obtain fuel assurance to address [the system needs during a severe winter]," by providing incentives for resources to provide reliability services (e.g., incremental fuel procurement) that would not have been provided otherwise.[32]

In January 2015, while discussion of alternative winter programs was on-going, the Commission provided the region with additional guidance. On January 20, in response to a Motion for Clarification submitted by the New England Power Generators Association ("NEPGA"), the Commission clarified that, if ISO-NE determined that a winter reliability solution was necessary for the 2015-2016 winter and for future winters, it should "develop an appropriate market-based solution through the stakeholder process that can be implemented beginning with the 2015-2016 winter."[33] In light of this order, much of the discussions in the NEPOOL stakeholder process were about potential market-based solutions to address winter reliability issues. Those market-based solutions included proposed further increases to the RCPF values and the potential of a scaled-down version of PFP to purchase a fuel-neutral, winter-based reliability product for the winters of 2015-16 through 2017-18. Those potential solutions had supporters and detractors, and each of them presented a host of additional issues that were proving to make achievement of a broadly accepted market-based proposal extremely challenging.

In addition, ISO-NE sought rehearing of the January 20 Order to permit the continuation of the 2014-15 Program, possibly it suggested, with an expanded scope to encompass other resource types. ISO-NE noted that options for developing a market-based solution in the context

[30] All NEPOOL Markets Committee meeting materials can be found at: http://www.iso-ne.com/committees/markets/markets-committee.

[31] The only modifications to the 2014-15 Program mentioned by ISO-NE at that time were related to price indexing v. fixed price, a total energy equivalent v. fuel quantities, and extended duration v. year-by-year. At that time in the NEPOOL process, there was no mention of ISO-NE expanding compensation eligibility to other resources types, such as nuclear, coal and hydro. *See* ISO-NE presentation to Markets Committee (dated Nov. 12-13, 2014), *available at*: http://www.iso-ne.com/static-assets/documents/2014/11/a10_iso_presentation_11_13_14.pptx.

[32] *See* ISO-NE presentation to the Markets Committee for its January 13-14, 2015 meeting, *available at*: http://www.iso-ne.com/static-assets/documents/2015/01/a06a_iso_presentation_01_13_15.pptx.

[33] *ISO New England Inc.*, 150 FERC ¶ 61,029 (2015) at P 10 (the "January 20 Order").

of existing obligations were "at best, potentially less effective than the winter reliability programs, and, at worst, less effective, inefficient, controversial and expensive to implement."[34]

Three months later, in April, the Commission provided still more guidance to the region. On April 17, 2015, the Commission granted ISO-NE's rehearing request to allow the possibility that ISO-NE may file additional out-of-market winter reliability programs until PFP becomes fully effective in 2018.[35] The Commission's April 17 Order, citing ISO-NE's unilateral suggestion that it might expand the scope of prior out-of-market solutions to resources other than fuel oil and LNG, concluded as follows:

> "[w]e find that an expanded version of the current winter program might better produce the desired results in terms of reliability than the introduction, at this point in time, of the market-based solutions examined by ISO-NE. … However, the Commission expects ISO-NE to abide by its commitment to work with stakeholders to expand any future out-of-market winter reliability program to include 'all resources that can supply the region with fuel assurance,' such as nuclear, coal, and hydro resources. *To that end, if any future out-of-market program is not fuel neutral, we expect that ISO-NE would provide a detailed description of the options it considered to make the program fuel neutral and why those options were ultimately not included*."[36]

The April 17 Order resulted in an almost immediate cessation of any focus on a market-based solution. Following that Order, ISO-NE abandoned any further efforts on a market-based solution and presented a proposal based on the Winter 2014-15 Program, but with expanded compensation eligibility to include other resource types and to eliminate the supplemental demand response program. Together with the proposal to expand the scope of resources eligible for the out-of-market supplemental winter payments, ISO-NE proposed also to reduce from 15 to 10 days the maximum inventory for which the Program would cover carrying costs. Given the Commission's April 17 Order and ISO-NE's position, stakeholder efforts to develop and pursue a market-based solution also ceased and all discussions in the stakeholder process focused on the development of an out-of-market program.

Two competing proposals emerged for final vote, with NEPOOL members and state officials seeking a proposal that was targeted solely to resources that would provide incremental reliability benefits over and above whatever the markets were providing. There was complete agreement that, because more resources would be receiving out-of-market payments, the ISO-NE Proposal would be more expensive to the region than a program that limited payments to those resources that had previously proved successful in achieving the winter program's objective. Stakeholders also were not receiving any information that was persuading them that an out-of-market program that promised incremental out-of market payments to nuclear, coal, biomass or certain hydro resources provided any incremental benefit for those added costs. As a result,

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[34] *Rehearing Request of ISO New England Inc.*, Docket No. ER14-2407-000 at p. 2 (Feb. 19, 2015).

[35] *Order Granting Rehearing*, 151 FERC ¶ 61,052 (2015) (the "April 17 Order").

[36] April 17 Order at P 17 (footnote omitted and emphasis added).

consensus built around a proposal, modeled largely after the successful 2014-15 Program, accepting ISO-NE's proposal to reduce the fuel inventory for which supplemental out-of-market payments might be made and rejecting ISO-NE's proposal to expand the types of resources receiving those supplemental out-of-market payments.

The proposal that ultimately became the NEPOOL Proposal was initially presented for discussion at the Markets Committee by NESCOE, reflecting the unanimous position of all six New England states. Following discussion, this alternative to the ISO-NE Proposal was offered for stakeholder consideration jointly by representatives from each of the six NEPOOL governance sectors. Those joint-sponsors included representatives of the following NEPOOL members: Conservation Services Group ("CSG") (a member of the Alternative Resources Sector), TransCanada (a member of the Generation Sector), Connecticut Office of Consumer Counsel ("CT OCC") (a member of the End User Sector), United Illuminating ("UI") (a member of the Transmission Sector), Massachusetts Municipal Wholesale Electric Company "(MMWEC") (a member of the Publicly Owned Entity Sector and joint action agency for 21 municipalities in Massachusetts), and Energy America (a member of the Supplier Sector).

At the Markets Committee (June 2-3 meeting), the jointly-sponsored proposal was the subject of two proposed amendments, one that passed and one that did not. The proposed amendment that passed based on a show of hands, and was supported by ISO-NE, was offered by Exelon Generation Company, LLC ("Exelon"). The Exelon-sponsored amendment modifies the LNG component to permit gas-fired Generator Assets to be eligible for compensation, but only for those assets that were capable of receiving pipeline gas ***or*** supplies of LNG. The proposed amendment that failed, offered by Calpine Energy Services, LP ("Calpine"), would change the compensation formula for the LNG component so as to permit compensation for purchased LNG quantity up to a specified cap, rather than just support payments for unused LNG quantity (the "Calpine Amendment"). That Calpine Amendment was not supported by ISO-NE, and failed based on a show of hands of the Markets Committee.

The modified jointly-sponsored proposal was then voted by the Markets Committee and achieved very broad support, receiving over 84% Vote in favor[37] of a motion to recommend Participants Committee approval.[38] The Participants Agreement provides that, if an ISO-NE proposal is modified in any way that ISO-NE does not support, it is entitled to have a vote on its proposal with any changes it finds acceptable.[39] Properly exercising its rights, ISO-NE indicated that it did not support the proposal just recommended by the Markets Committee and requested the Markets Committee to vote the ISO-NE's proposal with the Exelon-sponsored amendment

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[37] The individual Sector votes of the Markets Committee on the jointly-sponsored proposal were: Generation (7.34% in favor, 9.79% opposed, 4 abstentions), Transmission (17.13% in favor, 0% opposed, 0.5 abstention), Supplier (11.42% in favor, 5.71% opposed, 9 abstentions), Alternative Resources (14.38% in favor, 0% opposed, 2 abstentions), Publicly Owned Entity (17.13% in favor, 0% opposed), and End User (17.13% in favor, 0% opposed).

[38] The Markets Committee-recommended proposal included the Exelon-sponsored amendment.

[39] *See* Participants Agreement § 11.1.2.

that it found acceptable. That modified ISO-NE proposal was supported only by a 19.36% Markets Committee Vote in favor.[40]

As required by the NEPOOL stakeholder process, the two proposals, along with the recommendation of the Markets Committee, were then presented for consideration by the Participants Committee, and these totals swung even more in favor of the NEPOOL Proposal.[41] At its June 25, 2015 meeting, the Participants Committee approved the NEPOOL Proposal with a Vote of 87.10% in support. ISO-NE again indicated that it would not support the NEPOOL Proposal and sought a separate vote on its proposal, as it is entitled to do.[42] The ISO-NE Proposal failed with only 13.43% in favor. The voting results are tabulated in Attachment N-1g.

V. THE NEPOOL PROPOSAL

There is virtually unanimous agreement in the region that a supplemental winter reliability program is needed until PFP becomes effective in 2018. However, key elements of the 2014-15 Program expired by their own terms on March 15, 2015.[43] As such, confronting the 2015-16 and subsequent winters without a supplemental program in place was not considered viable, so the Commission is presented with two alternative supplemental, out-of-market winter reliability programs to remain in place until PFP is implemented. To participate in any of the programs contained within the NEPOOL Proposal (as with the ISO-NE Proposal), a Participant must notify ISO-NE by the October 1 immediately preceding the relevant winter.

The core components of the NEPOOL Proposal are described in detail below.

A. Unused Oil Inventory

The unused oil inventory component of NEPOOL Proposal (which is the same as one of the components of the ISO-NE Proposal) would require generators to have a minimum level of oil at the beginning of winter in order to receive an end-of-season payment to offset the carrying costs of unused oil. Not all carrying costs are intended to be offset by this feature, as such compensation is intended to encourage generators to rely on upfront inventory, rather than replenishment to provide sufficient oil in tanks to meet New England's winter needs. To

[40] The individual Sector votes of the Markets Committee on the ISO-NE Proposal were: Generation (11.41% in favor, 5.71% opposed, 5 abstentions), Transmission (4.28% in favor, 12.84% opposed, 1 abstention), Supplier (3.67% in favor, 13.45% opposed, 4 abstentions), Alternative Resources (0% in favor, 14.38% opposed), Publicly Owned Entity (0% in favor, 17.12% opposed), and End User (0% in favor, 17.12% opposed). Provisional Member Group Seat vote results were 0% in favor and 0.02% opposed.

[41] Prior to approval of the NEPOOL Proposal, the Participants Committee considered and voted on the Calpine Amendment. The Participants Committee failed to approve the Calpine Amendment with a 49.61% Vote in favor. *See* Attachment N-1g ("Calpine Amend").

[42] *See* Participants Agreement § 11.1.3.

[43] The 2014-15 Program rules for incentivizing dual-fuel commissioning have been retained in Section III.K.5.

participate in this aspect of the program, a generator must be capable of operating on oil. Dual-fuel generators are eligible to the extent that ISO-NE determines they have demonstrated (or will demonstrate on or before January 1 of the relevant winter) their ability to run on oil.[44]

As with the 2014-15 Program, under the NEPOOL Proposal (and also the ISO-NE Proposal), ISO-NE must evaluate a generator's fuel oil inventory on December 1 of the relevant winter, and any inventory shall be deemed eligible for compensation if it meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) the supply sufficient to operate the generator for 10 days at full load.[45] This particular requirement ensures that the program dollars are paying for inventory that is incremental to oil that generators would have purchased if no program was in place. Generators have a grace period to reach targets until January 1, but will be compensated based on the oil inventory as of December 1.[46]

Under either Proposal, Participants will be compensated after March 15 of the relevant winter by calculating the Eligible Inventory, multiplied by the rate set by ISO-NE and expressed in $/barrel,[47] multiplied by any Performance Adjustment.[48] Reflecting the fact that both Programs would be in place for three winter periods, a new payment rate would be established annually to allow ISO-NE to reflect current market conditions. To calculate the annual rate, ISO-NE will use the methodology developed for the 2014-15 Program and post the rate on the ISO-NE website no later than July 15 prior to each winter.[49]

B. Unused LNG Contract Volumes

The next feature of the NEPOOL Proposal (which was also included in the 2014-15 Program and is included in the ISO-NE Proposal) is compensation for unused LNG volumes.[50] Gas-fired generators (including dual-fuel generators) must be able to receive pipeline gas or

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[44] Section III.K.2(a).

[45] This feature is a change from the 2014-15 Program which required the supply to be sufficient to operate the generator for 15 days at full load.

[46] Section III.K.2(b).

[47] Section III.K.2(c). The rate to be paid will be updated annually under both the NEPOOL and ISO-NE Proposal to reflect fuel oil costs at the time.

[48] Section III.K.2(c). The performance adjustment will be the same adjustments under both Proposals that was used in the successful 2014-15 Program. The Performance Adjustment is determined by taking the "winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System", and dividing by the total number of winter hours.

[49] Section III.K.1(g). The payment rate methodology is described by the Analysis Group in its May 28, 2014 memorandum to the NEPOOL Markets Committee, *available at*: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun32014/a02a_analysis_group_memo_05_28_14.pdf. The rate for the 2014-15 Program was $18/bbl.

[50] *See generally* Section III.K.3.

supplies of LNG in order to be qualified to participate in this component of the program.[51] Those qualifying generators that contract for LNG will receive an end-of-season payment to offset the risk of unused contract volumes. NEPOOL's (and ISO-NE's) aim in creating this component is to provide incentives for generators to use LNG as a peaking fuel, and to augment use of pipeline gas.

Under the NEPOOL Proposal (as well as the ISO-NE Proposal), ISO-NE will accept generators for this component of the program on a first come/first served basis up to 6 billion cubic feet ("Bcf") (equivalent to approximately 1 million barrels of oil).[52] Each participating generator is required to submit each executed contract to ISO-NE by December 1 of the relevant winter, along with a certificate that confirms the contract's take or pay construct, and includes specifications of the volume and term of the contract.[53] The LNG component of the NEPOOL Proposal (as well as the ISO-NE Proposal), has no required minimum, due to the fact that some generators require small amounts of LNG, and because the reliability needs for New England can be met through the above-described unused oil program.

A generator that participates in the LNG component of the NEPOOL Proposal (like the ISO-NE Proposal) will be compensated at the end of the winter based on the lesser of December 1 and March 1 contract volumes – at a maximum amount of the fuel necessary to permit the generator to operate for four days at full load.[54] Generators are compensated at a set rate that is tied to the annual payment rate for unused oil inventory, converted to $/MMBTU. Payments to generators are reduced by the same Performance Adjustment utilized in the unused oil inventory program.[55]

C. <u>Demand Response Program</u>

The last portion of the NEPOOL Proposal, which unlike the other two components of the Proposal is *not* the same as the ISO-NE Proposal, reinstates the previously successful incremental demand response program.[56] This program is available for Participants to supply demand reductions upon dispatch that would help maintain Thirty-Minute Operating Reserve during the relevant winter. The incremental demand response program contained within the NEPOOL Proposal is open to demand response resources that are either (1) new assets that are not currently participating in the wholesale electricity markets, or (2) resources that are currently

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[51] Section III.K.3(a).

[52] Section III.K.3(b).

[53] Section III.K.3(c).

[54] Section III.K.3(d).

[55] *Id*.

[56] A supplemental demand response component was contained in both the 2013-14 and 2014-15 Programs. *See also* Healy Affidavit at pp. 2-3.

participating in FCM but have *additional* capacity beyond that needed to meet their Capacity Supply Obligation.[57]

Under the NEPOOL Proposal, the payment rate for the demand response program will be equivalent to the annual rate established for the unused oil inventory component[58] and, as with the 2014-15 Program, the demand response program will be limited to 100 assets at a level not to exceed 100 MW.[59]

VI. THE NEPOOL PROPOSAL IS JUST AND REASONABLE

Both ISO-NE and NEPOOL have drafted proposals that have many common elements that the Commission has already declared to be just and reasonable in its evaluation of the 2014-15 Program. In accepting that Program,[60] the Commission found that the 2014-15 Program "is a just and reasonable solution to address [winter] risks to reliability by creating incentives for market participants to provide additional reliability services … *which they would not have provided absent the program*."[61] The Commission recognized then that, in order to address New England's winter reliability needs, an out-of-market solution was just and reasonable.[62] The Commission's determination that the 2014-15 Program was just and reasonable is just as compelling today as it was when the Commission accepted it last fall. Therefore, the NEPOOL Proposal implementing the core elements of the 2014-15 Program is also just and reasonable.

In his testimony attached hereto, Alan A. Trotta details how a winter reliability solution is needed in the region to bridge the gap until the PFP capacity market rules are implemented in June 2018.[63] Mr. Trotta notes that the NEPOOL Proposal is designed to meet a specific reliability need, and as such "needs to remain limited in scope to exactly what's necessary to meet the reliability need – no more, no less."[64] The Commission noted the particular challenges to reliability in the New England region, and in line with such issues, the temporary nature of the 2014-15 Program, which informed the Commission's conclusion that the 2014-15 Program was just and reasonable.[65] The NEPOOL Proposal is also a temporary solution, designed to be a stop-gap measure only until the PFP incentive mechanism begins to take effect.

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[57] Section III.K.4.

[58] Section III.K.4(f).

[59] Section III.K.4(b).

[60] *See* September Order

[61] *Id*. at P 13 (emphasis added).

[62] The Commission refused to order a Section 206 proceeding to be initiated to compel ISO-NE to develop a market-based solution for the 2014-15 Winter. *See* September Order at P 41. Further, the Commission granted ISO-NE's rehearing request to "allow the possibility that ISO-NE may file additional out-of-market winter reliability programs," until PFP begins. *See* April 17 Order at P 17.

[63] Trotta Testimony at p. 2.

[64] *Id*.

[65] *See* September Order.

In its September Order, the Commission dispelled arguments that the 2014-15 Program was unduly discriminatory (and therefore not just and reasonable) in "reject[ing] arguments that, because the [2014-15 Program] does not pay all resources for providing firm fuel service, it is unduly discriminatory."[66] The Commission found that it was reasonable and not unduly discriminatory to provide incremental incentives only for market participants that will procure additional fuel before winter as a result of payments under the 2014-15 Program.[67]

The NEPOOL Proposal seeks the same objective sought by the just and reasonable 2014-15 Program. This objective is necessarily designed to incentivize certain resources to go "above and beyond" in fuel procurement: that is, to carry incremental fuel inventory to provide incremental reliability during cold winter days. The NEPOOL Proposal would compensate such resources for those measures, through energy and reserve market payments as fuel is burned and through limited program payments for inventory that must be carried into the future, which the Commission has determined is proper.

VII. THE NEPOOL PROPOSAL IS PREFERABLE TO THE ISO-NE PROPOSAL

The NEPOOL Proposal is preferable to the ISO-NE Proposal for several reasons:

A. The NEPOOL Proposal Reinstates a Proven, Cost-Effective, Just and Reasonable Program

The NEPOOL Proposal is preferable to the ISO-NE Proposal because it re-institutes a known and reasonably priced interim solution that has proven to be successful in satisfying incremental winter reliability needs resulting from limited transportation for pipeline gas. Reflecting back on the success of the 2014-15 Program, ISO-NE recognized that the Program played a key role in ensuring power system reliability as it "provided incentives to generators to have oil inventory stored in site, or to have a contract for LNG deliveries to supplement pipeline gas supplies before the start of winter."[68] Peter Brandien, ISO-NE's Vice President of System Operations, acknowledged that the 2014-15 Program "proved invaluable, significantly boosting oil inventory in the region before the start of winter."[69] Further, ISO-NE recognized that the 2014-15 Program, and specifically, the end-of-season payment to help offset carrying costs of leftover oil inventory or unused LNG contracts, helped achieve the desired effect as "by the start of winter, the region was well positioned with fuel inventory."[70]

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66 *Id*. at P 15.

67 *Id.*

68 *See supra* note 28.

69 *Id.*

70 *Id.*

B. The NEPOOL Proposal Balances Costs with Benefits

The NEPOOL Proposal is also preferable to the ISO-NE Proposal because while the NEPOOL Proposal focuses incremental payments for incremental reliability benefits, the ISO-NE Proposal increases costs without any commensurate reliability benefit.[71] Unlike the ISO-NE Proposal, the NEPOOL Proposal is targeted to encourage specific behavior not incented by the existing market rules and ultimately avoids imposing on consumers costs for resources that already see market signals for providing firm fuel during the winter.[72]

The ISO-NE Proposal includes these same targeted payments for oil and LNG, but also expands payments to resources that are not expected to provide any measureable increase in seasonal reliability.[73] ISO-NE proposes to expand the type of generators eligible for compensation to other fuel types, like nuclear, coal, biomass, and certain hydro resources. Expanding the types of resources eligible for compensation in this manner unquestionably increases the supplemental out-of-market costs, by some estimates as much as $46 million annually.[74] These increased costs to consumers are a direct result from ISO-NE paying more resources under its Proposal. As the number of eligible resources will increase under the ISO-NE Proposal, so too will the costs of the program increase, commensurate with the expansion of the eligible resource base.[75]

What those opposing the ISO-NE Proposal find most objectionable though, is not the increased costs (particularly recognizing that other changes from the 2014-15 Program were made that would reduce costs from that Program), but that they see no incremental benefit for such assured increased costs.[76] The ISO-NE Proposal would compensate generators, like nuclear, coal, and hydro, for doing precisely what they already have been doing in preparation for energy and reserve market operations during the winter months.[77] These resources would not deliver incremental reliability benefits, yet they would be compensated as if they were. This

[71] *See generally* Bentz Testimony; Flumerfelt Testimony; Trotta Testimony; Forshaw Affidavit; Healy Affidavit.

[72] As Chairman Norman C. Bay notes in his dissent in *PJM Interconnection, L.L.C v. Essential Power Rock Springs, LLC*, 151 FERC ¶ 61,208 (2015), reliability solutions that compensate generators without any increase in reliability cause an RTO to "purchase[] little certainty for what may be a lot of money." ISO-NE has provided no analysis showing that its proposed expanded program would result in a construct where benefits would be "at least roughly commensurate with the costs."

[73] *See, e.g.*, Flumerfelt Testimony at p. 5.

[74] Bentz Testimony at pp. 17-18 (*see* Table 1).

[75] *Id*. at pp. 16-17.

[76] Trotta Testimony at pp. 2-4; Forshaw Affidavit at pp. 3-7.

[77] *See, e.g.*, Bentz Testimony at pp. 19-20; Flumerfelt Testimony at p. 5; Trotta Testimony at pp. 3-4; Forshaw Affidavit at pp. 6-7.

requirement of ISO-NE that the region pay something for nothing has galvanized support for the NEPOOL Proposal, and likewise opposition to the ISO-NE Proposal.[78]

In its efforts to explain its proposal, ISO-NE pointed to the Commission's indication that it would hold ISO-NE to its unilateral suggestion in January that it might expand the winter program to resources other than those relying on fuel oil and LNG absent a detailed description as to why the program is not fuel neutral.[79] While NEPOOL has demonstrated through its prior votes that it historically has sought and supported fuel neutrality when working through market solutions, motivations are different and broader if an out-of-market solution is being defined. Here, market participants and state officials are seeking to minimize interference with the market, and also to minimize out-of-market payments. The 2014-15 Program reflected just such a narrowly tailored out-of-market program with resulting lower costs.

As explained in the testimony of John Flumerfelt of Calpine, who represents a member in the Supplier Sector, "[w]e do not believe that simply including additional fuel types in a non-market solution results in a fuel neutral program."[80] Mr. Flumerfelt concludes that, absent a true market-based program, the NEPOOL Proposal is the best option for the region until PFP is implemented because it has already been "proven to be a cost-effective insurance policy that has helped maintain winter reliability"[81] and "is appropriately limited in scope and more targeted toward compensation that will promote incremental reliability."[82]

We note also that neither the ISO-NE Proposal nor the NEPOOL Proposal is fuel neutral. ISO-NE, in order to support its suggestion of fuel neutrality, elected to modify the objective of the winter program. In 2013, ISO-NE identified that its objective for the 2013-14 winter was to develop a solution that obtained the incremental energy needed if colder than normal weather occurs, with minimal market distortions.[83] Similarly, the fundamental objective of the 2014-15 Program was to improve the region's overall fuel security.[84] Further, in addressing the fact that the 2014-15 Program excluded other types of units, including nuclear and hydro resources, ISO-NE stated that "the primary objective of the program is to ensure fuel adequacy, and it is difficult to identify additional fuel requirements for these types of resources, which typically have low-cost fuels or extended fuel supplies to meet their expected operation."[85] Rather than continue to focus on providing incremental fuel assurance and reliability support, ISO-NE now has redefined

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[78] Even if there is an incremental benefit provided under the ISO-NE Proposal, there has been no indication from ISO-NE that there is a reliability need in the first place for providing compensation under the winter program to "Other Stored Fuels" or that any incremental benefit justifies the additional costs.

[79] *See* ISO-NE Transmittal Letter, Attachment I-1a; *see also* April 17 Order.

[80] Flumerfelt Testimony at p. 3.

[81] *Id*. at p. 4.

[82] *Id*. at p. 5.

[83] June 2013 Filing at p. 6.

[84] July 2014 Filing at p. 8.

[85] *Id*. at p. 9.

the objective to be one of maintaining on-site fuel. In so doing, it has excluded many forms of renewable generation and all forms of demand response. NEPOOL is not suggesting that, for example, wind or solar resources should be eligible for supplemental payments under the winter program in the quest for "fuel neutrality" for the same reason it is not supporting the application of those payments to nuclear, coal, biomass and hydro facilities. There is no expectation that such additional payments will have any incremental reliability benefits. These are among the reasons why the NEPOOL Proposal is not a "fuel neutral" program. [86]

In short, the NEPOOL Proposal remains focused on the specific and consistent objective of past winter programs. It targets resources to incentivize maximum preparation for fuel capabilities that otherwise would not occur in the markets, thus ensuring incremental support for winter reliability. The ISO-NE Proposal does the same, somewhat, but requires that substantial additional payments, which in the view of many is unnecessary, if not unreasonable. Accordingly, the NEPOOL Proposal is preferable because it provides a real benefit to the region: increased reliability without unnecessary and unwarranted increases in the overall cost of the program.[87]

C. The NEPOOL Proposal is Overwhelmingly and Broadly Supported[88]

Lastly, the NEPOOL Proposal better addresses NEPOOL stakeholder concerns. This is evidenced by the broad support the NEPOOL Proposal received, with a 87.10% Vote in favor, including support from all six NEPOOL governance Sectors. In fact, the NEPOOL Proposal was co-sponsored by a representative in each Sector. In comparison, the ISO-NE Proposal only received a 13.43% Vote in favor. While stakeholder support does not alone prove that the NEPOOL Proposal is just and reasonable and preferable, "stakeholder consensus is an important factor to be considered in reviewing the justness and reasonableness of a rate design."[89]

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[86] Interestingly, in the July 2014 Filing of the 2014-15 Program, ISO-NE opined that "complete resource neutrality requires a market-based clearing mechanism and a uniform, defined product without significant administrative triggers." *See id.*

[87] *See supra* note 71.

[88] *See* Attachment N-1g.

[89] *Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083 at P 172 (2008); *see also PJM Interconnection LLC*, 119 FERC ¶ 61,063 at P 56 (2007) (finding that the position of the majority of stakeholders, even when there is not complete stakeholder consensus, should be considered in a finding of justness and reasonableness); *New England Power Pool, et al.*, 105 FERC ¶ 61,300 at PP 22-23 (2003), *reh'g denied*, 109 FERC ¶ 61,252 (2004).

VIII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[90] However, the NEPOOL Proposal does not change a traditional "rate", and neither NEPOOL nor ISO-NE are traditional investor-owned utilities. In light of these circumstances, NEPOOL submits the following additional information in substantial compliance with relevant provisions of Section 35.13, and requests a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

35.13(b)(1) – Materials included herewith are identified more specifically on page 3 of this transmittal letter and the joint transmittal letter accompanying part 1 of this filing.

35.13(b)(2) – NEPOOL requests that the changes to Appendix K to Market Rule 1 (i.e., the NEPOOL Proposal) become effective September 14, 2015.

35.13(b)(3) – Pursuant to Section 16.11(a)(iv) of the Second Restated NEPOOL Agreement and Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in Attachment I-1e. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in Attachment I-1e to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in Section VIII of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Sections IV, V, VI and VII of this transmittal letter.

35.13(b)(6) – As discussed in Section IV of this transmittal letter, the changes to the Tariff reflect the results of the Participant Processes required by the Participants Agreement. The NEPOOL Proposal was approved by a NEPOOL Vote of 87.10%.

35.13(b)(7) – NEPOOL has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

[90] 18 C.F.R. § 35.13 (2014).

35.13(c)(1) – The Tariff changes herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – ISO-NE does not provide services under other rate schedules that are similar to the wholesale, resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the NEPOOL Proposal's Tariff revisions filed herein.

IX. CONCLUSION

For the reasons stated in this Letter, and in the attached testimony and affidavits supporting this filing, the Commission should approve the NEPOOL Proposal, which is just and reasonable and preferable to the ISO-NE Proposal, without suspension or hearing, to be effective September 14, 2015.

Respectfully submitted,

NEPOOL PARTICIPANTS COMMITTEE

By:______________________________

David T. Doot
Joseph H. Fagan
Sebastian M. Lombardi
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
(860) 275-0102
dtdoot@daypitney.com
jfagan@daypitney.com
slombardi@daypitney.com

Its Attorneys

Dated: July 15, 2015

ATTACHMENT N-1b

Testimony of Jeffrey W. Bentz

Director of Analysis, New England States Committee on Electricity

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER15-___-000**
New England Power Pool	)	

PREPARED TESTIMONY OF JEFFREY W. BENTZ IN SUPPORT OF THE NEW ENGLAND POWER POOL'S PROPOSED WINTER RELIABILITY PROGRAM

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and by whom, and in what capacity, you are employed.

A. My name is Jeffrey W. Bentz, and I am employed by the New England States Committee on Electricity ("NESCOE") in the position of Director of Analysis. NESCOE's legal business address is 655 Longmeadow Street, Longmeadow, MA, 01106. NESCOE is the Regional State Committee for New England. It is governed by a board of managers ("NESCOE Managers") appointed by the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont and is funded through a regional tariff administered by ISO New England Inc. ("ISO-NE"). 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 reasonable cost over the long term, consistent with maintaining reliable service and environmental quality.

Q. Please summarize your educational background.

A. I have a Bachelor of Science in Accounting from Central Connecticut State University. I received my certificate as a Certified Public Accountant from the State of Connecticut Board of Accountancy on July 6, 1993.

Q. Please briefly summarize your related professional experience prior to joining NESCOE.

A. Before joining NESCOE in January 2010, I was employed by various entities providing administrative services to MASSPOWER, a Massachusetts joint venture that owned a 240 megawatt ("MW") combined-cycle generation facility located in Springfield, Massachusetts. Over the course of nearly 20 years, I served as Controller and General Manager of MASSPOWER. I managed day-to-day activities on behalf of the joint venture, including operations, finance, technology, risk management, maintenance, and regulatory compliance. I was responsible for setting the annual strategic and business planning process, including Strengths, Weaknesses, Opportunities, and Threats analysis, operating plans, budgets, and quarterly updates. In addition, I led merger and acquisition teams and participated in various corporate teams during my tenure with companies such as J. Makowski Co., U.S. Generating Co., Pacific Gas and Electric, Cogentrix, and BG Group. Prior to my tenure with MASSPOWER, I was a Senior Accountant with Arthur Andersen and Company, performing audit activities primarily in the utility and brokerage industries.

Q. Please describe your role at NESCOE and some of your recent experience with the NEPOOL stakeholder process.

A. I provide NESCOE Managers, who are comprised of officials in all six New England states that have been appointed by their Governors, with analysis of and recommendations about various proposals advanced by ISO-NE, market participants, other stakeholders, and state entities, primarily in the context of the New England Power Pool ("NEPOOL") Markets Committee. In that capacity, I work closely with NESCOE Managers and certain state agency staff representing each of the six New England states. Over the past several years, I have worked closely with NEPOOL stakeholders, ISO-NE personnel and state representatives in attempting to achieve consensus on a host of issues related to the Forward Capacity Market ("FCM") and energy market refinements. For example, on behalf of NESCOE, I worked on the development and implementation of a downward-sloping demand curve in the FCM and have promoted efforts to improve price formation in the energy market. I represented NESCOE and provided an accompanying statement at FERC's September 25, 2013 Technical Conference on Centralized Capacity Markets in RTOs/ISOs, Docket No. AD13-7. Over the last several years, I have also worked closely with members of the New England Gas-Electric Focus Group to better understand, and explore potential solutions to, New England's gas-electric interdependency issue. As part of NESCOE's close engagement on this issue, I participated in FERC's August 20, 2012 Technical Conference on the Coordination Between Natural Gas and Electricity Markets, Docket No. AD12-12.

Q. What is the purpose of your testimony?

A. While I am a NESCOE representative, I was very involved in the NEPOOL stakeholder process in helping to define and advocate for the winter reliability program that was overwhelmingly approved by NEPOOL (now known as the "NEPOOL Proposal), and I prepared this testimony at NEPOOL's request to provide the following: (1) background information on the winter reliability programs that were designed to improve fuel security during winter months; (2) a description of the NEPOOL Proposal; (3) an explanation of the development of the NEPOOL Proposal, including the NEPOOL stakeholder process; and (4) a recommendation in support of the NEPOOL Proposal.

Q. Please summarize your conclusions.

A. First, I conclude that the NEPOOL Proposal continues a proven, effective and efficient program that, as a temporary measure, will continue to be a just and reasonable and not unduly discriminatory means of providing additional reliability during the next three winter seasons in New England. Second, I conclude that the ISO-NE Proposal is unlikely to deliver *incremental* reliability benefits associated with expanded program eligibility and removal of demand response resources from the program, but is likely to come at an increased cost. Maintaining a known and reasonably priced interim solution is the best course of action, and I recommend that the Commission approve the NEPOOL Proposal.

II. FUEL ASSURANCE AND THE WINTER RELIABILITY PROGRAMS

A. FUEL ASSURANCE IN NEW ENGLAND

Q: Please give an overview of fuel assurance issues in New England.

A: New England's acute experiences with infrastructure constraints and fuel assurance issues are well known and documented. To summarize briefly and non-exhaustively, in 2014, approximately 43% of the electric energy produced within ISO–NE was from natural gas-fired resources.[1] Very few of these natural gas-fired resources hold firm entitlements to natural gas transportation or supply.[2] As a result, New England's fleet is increasingly reliant on the availability of interruptible natural gas transportation to deliver its "just-in-time" fuel supply. During the winters in particular, the availability of such transportation and alternative fuel supply

[1] ISO New England Inc., Presentation to the Planning Advisory Committee: *New England 2015 Regional System Plan (RSP15) Load, Energy and Capacity Resource Overview* (April 28, 2015), at 5, available at http://www.iso-ne.com/static-assets/documents/2015/04/a3_rsp15_load_capacity_resource_overview.pdf. New England's increasing reliance on natural gas-fired resources comes as New England becomes less reliant on older, less-efficient, and typically more carbon-emitting resources, such as coal.

[2] Eastern Interconnection Planning Collaborative, *Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces* (Apr. 4, 2014), at Exhibit 7: ISO-NE Generators Holding Mainline Firm Transportation Contracts, available at http://www.eipconline.com/uploads/Exhibit_7_-_ISO-NE_Generator_Contracts_-_Final_Draft_4_Apr14.pdf.

is limited and when it is available during such times, it may come at very high and volatile prices. Limited transportation of fuel can adversely impact electric system reliability, and consumer prices have been materially impacted.[3] The Commission has recognized the critical implications of fuel assurance for system reliability and volatile and higher prices paid by consumers.[4]

Q: Has New England identified the problems and worked toward solutions?

A: The region has been focused and actively engaged on energy infrastructure, supply adequacy, and fuel assurance issues for the past several years.[5] The New England Gas-Electric Focus Group, established in 2012, enabled members of the region's natural gas and electricity industries to "share information, further discuss and identify regional challenges and explore potential solutions."[6]

Q: Have New England stakeholders performed analyses or otherwise studied the region's infrastructure and supply adequacy and consequent effect on fuel assurance?

A: Yes, the issue has been studied extensively over the past several years by many organizations, with diverse shareholder, power system and consumer perspectives. Among these analyses are ISO-NE's initial work with ICF International in 2012 and, more recently, the

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3 *See*, *e.g.*, U.S. Energy Information Administration, Electricity Monthly Update (Mar. 4, 2015), available at http://www.eia.gov/electricity/monthly/update/archive/february2015/; *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators; Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators*, Order on Technical Conferences, 149 FERC ¶ 61,145 (2014) ("Fuel Assurance Order")

4 Fuel Assurance Order at P 1.

5 *See*, *e.g.,* ISO-NE's Strategic Planning Initiative, more information available at http://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative; NESCOE comments on the U.S. Department of Energy's Quadrennial Energy Review, available at http://www.nescoe.com/uploads/CommentstoDOEonQER_21May14.pdf; and NESCOE's comments on fuel assurance filed in *ISO New England Inc.*, Docket Nos. AD13-7-000 and AD14-8-000 (March 20, 2015), available at http://www.nescoe.com/uploads/FuelAssurance_AD13-7_20Mar2015.pdf.

6 New England Gas-Electric Focus Group, Final Report (March 28, 2014), at 1, available at http://www.nescoe.com/uploads/NEGas-ElectricFocusGroup_FinalReport_31Mar2014.pdf.

Eastern Interconnection Planning Collaborative's comprehensive study by Levitan & Associates in 2015. For my organization's part in regional efforts to study the issue, NESCOE commissioned Black & Veatch to study the natural gas/electricity interface in 2012/2013.[7]

Q: Has New England implemented market enhancements or other solutions to address its fuel assurance challenges?

A: The region has developed and implemented a host of electricity market enhancements that are designed to address fuel assurance-related concerns and improve generator performance, and the New England states have been working in earnest on infrastructure and supply adequacy in furtherance of reliability, environmental and consumer interests.[8] The most notable wholesale market adjustment is ISO-NE's so-called Pay-for-Performance ("PFP"), reforms to the FCM. According to ISO-NE, PFP is the "long-term, market-based solution" to address fuel assurance issues.[9] However, due to the three-year forward nature of the FCM, this enhancement to the market will not be implemented until June 1, 2018. The region has broadly agreed that, until PFP has been implemented, interim rules referred to as the Winter Reliability Program, which have been successfully employed the last two winters, are necessary to ensure a back-up to limited natural gas availability from the pipelines serving New England.[10] In addition, ISO-NE has implemented a number of complementary electricity market measures that are intended to

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[7] Links to the different phases of the Black & Veatch study are available at http://www.nescoe.com/Gas_Supply_Study.html. For a partial list of additional gas-electric studies, *see* n. 8 of NESCOE's Comments on the October 30, 2014 Massachusetts Low Demand Analysis, available at http://www.nescoe.com/uploads/MALowDemandStudy_Oct30Mtg_NESCOEComments_4Nov2014-1.pdf.

[8] New England Governors, *Actions for a Cleaner, More Reliable and More Affordable Energy Future* (Apr. 24, 2015) ("New England State Actions"), available at http://www.nescoe.com/uploads/6_State_Action_Plan_FINAL_4-22-15_1-5.40_pf.pdf.

[9] ISO New England Inc., Fuel Assurance Status Report, filed in Docket Nos. AD13-7-000 and AD14-8-000 (Feb. 18, 2015) ("Fuel Assurance Status Report"), at 5, available at http://www.iso-ne.com/static-assets/documents/2015/02/Final_for_Filing__Fuel_Assurance_Report.pdf. While outside of the scope of this proceeding, in any discussion of PFP, it is important to note, as does ISO-NE, that PFP is expected to improve generator performance and impact fuel assurance, but may not provide a complete solution to the region's energy infrastructure challenges and related consumer cost impacts. *See, e.g., id.* at 4.

[10] *Id.* at 7-9.

address fuel assurance issues and improve generator performance, and as noted, the New England states are working to advance other diverse energy infrastructure intended to advance power system reliability, environmental and consumer needs.[11]

B. WINTER RELIABILITY PROGRAMS

Q: What are the Winter Reliability Programs?

A: The Winter Reliability Programs are three separate efforts to address fuel assurance in a targeted way by providing incentives for certain resources to improve incrementally the fuel security for the region to a more satisfactory level for an interim period during the winter months. All three Winter Reliability Programs, described below, share certain characteristics. The need for a Winter Reliability Program first arose in early 2013, after the 2012/2013 winter exposed the region's vulnerability to fuel assurance issues.[12] ISO-NE put the first Winter Reliability Program in place for the 2013/2014 winter. ISO-NE has identified that a Winter Reliability Program of some sort is necessary to ensure electric reliability until the PFP reforms become effective in 2018, which will cover the 2018/2019 winter and subsequent periods going forward. The three separate Winter Reliability Programs are discussed in greater detail below. In this testimony, I will refer to them as follows: the 2013/2014 Winter Reliability Program ("Winter Program I"); the 2014/2015 Winter Reliability Program ("Winter Program II"); and the 2015/2016 to 2017/2018 Winter Reliability Program ("Winter Program III").

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[11] Fuel Assurance Order at PP 10-12; Fuel Assurance Status Report at 9-16; *see also* New England State Actions.

[12] ISO-NE, Winter 2013-14 Reliability Program Filing Transmittal Letter filed in Docket No. ER13-1851-000 (Jun. 28, 2013), at 5, available at http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jun/er13_1851_000_winter_2013_2014_6_28_2013.pdf.

Q. Is the Winter Reliability Program temporary?

A. Yes. According to ISO-NE, the market-based, long-term solution will arrive, in the form of PFP, on June 1, 2018.[13] Accordingly, Winter Program III, either in the form of the NEPOOL Proposal as I think should be implemented or the ISO-NE Proposal would expire on March 15, 2018. They are both, therefore, temporary in nature. This is significant because, again according to ISO-NE, a market-based short-term solution is not feasible.[14]

Q. Why does ISO-NE say a market-based, short-term solution is not feasible?

A. According to ISO-NE, "the options for developing a market-based solution in the context of existing obligations are, at best, potentially less effective than the winter reliability programs, and, at worst, less effective, inefficient, controversial and expensive to implement."[15]

1. 2013/2014 Winter Reliability Program (Winter Program I)

Q: Please describe the 2013/2014 Winter Reliability Program.

A: Winter Program I, which FERC had determined to be just and reasonable,[16] included, among other things, a supplemental procurement of up to 2.4 million MWh of energy (or 4.2 million barrels of oil based on an assumed 10,000 Btu/kWh heat rate and 137,000 Btu/gallon heat content) for the winter 2013/2014. The program included four main components: (1)

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13 ISO New England Inc., Rehearing Request filed in Docket No. ER14-2407-003 (Feb. 19, 2015) ("ISO-NE Rehearing Request"), available at http://www.iso-ne.com/static-assets/documents/2015/02/er14-2407-003_2-19-15_req_for_rehearing_clarification_order.pdf.

14 *Id.* at 7. In addition, New England states have other work in progress to alleviate infrastructure constraints in a variety of ways in the coming years. *See* New England State Actions; Connecticut Department of Energy And Environmental Protection's Energy Agenda, available at http://www.ct.gov/DEep/cwp/view.asp?a=4405&Q=499356&deepNav_GID=2121.

15 ISO-NE Rehearing Request at 2.

16 *ISO New England Inc., et al.*, Order Conditionally Accepting Tariff Revisions, 144 FERC ¶ 61,204 (2013), *reh'g denied*, 147 FERC ¶ 61,026 (2014).

demand response; (2) oil inventory service; (3) dual-fuel testing; and (4) market monitoring changes.[17]

Q: What was the objective of the 2013/2014 Winter Reliability Program?

A: Winter Program I was designed to address reliability risks associated with the region's increased reliance on natural gas-fired generation and resource performance during winter periods of stressed system conditions.[18] "In addition to the expected gas issues, [ISO-NE] learned that oil-fired generators and dual-fuel generators with the capability to operate on oil were not maintaining fuel inventory. ISO's pre-winter fuel surveys showed that oil-fired generators do not maintain full oil tanks."[19] By providing incentives for increased oil inventory and demand response services, Winter Program I enabled ISO-NE to address anticipated operational concerns, especially "during prolonged cold weather and during overnights and weekends."[20]

Q: Please explain the oil inventory service mechanics of the 2013/2014 Winter Reliability Program.

A: In exchange for a monthly payment, certain resources established an initial fuel inventory before the beginning of the winter season, defined as December 1 to March 1. For certain dual-fuel resources, replenished fuel inventories were also eligible for payment through the program. The program's monthly payments were based on an "as bid" price offered by eligible resources in an auction, in addition to payments for capacity, energy, and ancillary services.

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[17] *Id.* at P 2. Unlike the other provisions of Winter Program I, which were temporary, the market monitoring changes were proposed to remain in effect unless or until changed.

[18] *See id.*

[19] Joint Testimony of Robert G. Either and Peter Brandien on Behalf of ISO New England Inc., (Jun. 28, 2013), Docket No. ER13-1851 ("Ethier/Brandien Testimony"), at 13.

[20] *Id.*

Q: What resources were eligible to participate in the 2013/2014 Winter Reliability Program?

A: Participation in the supplemental procurement element of the program was available to demand response and oil-fired resources, as well as to certain dual-fuel resources.

Q: Was the 2013/2014 Winter Reliability Program successful in achieving its objectives?

A: Yes. According to ISO-NE, the program procured more than three million barrels of oil and "bridged the reliability gap."[21] It is clear that this additional oil was needed, as program participants burned 88% of the oil procured under the program during a colder than average winter – approximately 2.7 million barrels.[22]

2. <u>2014/2015 Winter Reliability Program (Winter Program II)</u>

Q: Please describe the 2014/2015 Winter Reliability Program.

A: Winter Program II, which FERC also determined to be just and reasonable,[23] modified the compensation structure of Winter Program I and included, among other things, compensation for unused oil inventory and unused liquefied natural gas (LNG) contract volumes for the 2014/2015 winter season. The program included six main components: (1) unused oil inventory; (2) unused LNG contract volumes; (3) dual-fuel incentives; (4) market monitoring changes; (5) dual-fuel audits; and (6) demand response.

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21 *ISO New England Inc., New England Power Pool Participants Committee*, Order Accepting Tariff Revisions, 148 FERC ¶ 61,179 (2014), at P 3.

22 *See* ISO New England Inc., NEPOOL Participants Committee Report, Mar. 6, 2015 ("ISO-NE COO Report"), at Slide 11, available at http://www.iso-ne.com/static-assets/documents/2015/03/march-2015-coo-report.pdf.

23 *ISO New England Inc., et al.,* Order Accepting Tariff Revisions. 148 FERC ¶ 61,179 (2014) ("Winter Program II Order"), *order on clarification*, 150 FERC ¶ 61,029 (2015), *reh'g granted*, 151 FERC ¶ 61,052 (2015).

Q: What was the objective of the 2014/2015 Winter Reliability Program?

A: The 2014/2015 Winter Reliability Program was intended to help in maintaining reliability by providing incentives (1) for dual-fuel resource participation, (2) demand response services, and (3) for adequate supplies going into the winter of oil and LNG contract volumes to back-up generation that might otherwise come from natural gas units that are unable to procure fuel on short notice in the winter when needed. This third incentive was accomplished by compensating generators for unused firm fuel inventories and LNG contract volumes.[24]

Q: Please explain the mechanics of the unused fuel inventory provisions of the 2014/2015 Winter Reliability Program.

A: Rather than Winter Program I's "as bid" payment for *initial* inventories, Winter Program II provided compensation for *unused* fuel inventories for certain eligible resources based on a standard payment rate, based on the cost of fuel oil. For oil-fired and dual-fuel resources, the amount of unused fuel eligible for compensation was based on the lesser of (i) the season-beginning (December 1) or (ii) program-ending (March 15) oil inventory. For LNG contract holders, the unused contract volumes eligible for compensation were based on the lesser of (i) the season-beginning or (ii) March 1 remaining contract volumes. The standard payment rate, \$18/barrel of oil or \$3/mmBtu of LNG, was identified in May 2014 based on an estimate of fuel oil carrying costs and other costs and risk factors, and was approved to be the rate for payments in Winter Program II.

[24] *See id.* at P 2.

Q: What resources were eligible to participate in the 2014/2015 Winter Reliability Program?

A: Participation in the unused fuel inventory component of the program was available to oil-fired resources, certain dual-fuel resources, and LNG "take-or-pay" contract holders. Demand response services that could assure availability during times of system stress in the winter were also eligible for compensation in the 2014/15 Winter Reliability Program, with compensation for such back-up resources also derived from the expected cost of fuel oil and set as part of the Program.

Q: Was the 2014/2015 Winter Reliability Program successful in achieving its objectives?

A: Yes. The Commission accepted Winter Program II as necessary for reliability over the 2014/2015 winter period.[25] The Commission's conclusions were verified by ISO-NE following the winter when it explained that "the program had the desired effect, with the region well positioned with fuel inventory at the start of [the 2014/2015] winter."[26] Again the region burned approximately 2.7 million barrels of program oil during the 2014-2015 winter period.[27]

3. Proposed 2015/2016-2017/2018 Winter Reliability Program (Winter Program III)

Q: Please provide an overview of the proposed Winter Program III.

A. Both NEPOOL's and ISO-NE's proposed programs will provide a similar level of incremental reliability during the three winter months in each of the next three years. The

25 *Id.* at P 39.
26 ISO-NE Rehearing Request at 4.
27 ISO-NE COO Report at Slide 11.

principal difference is that NEPOOL's program will provide this incremental reliability benefit at a lower cost to customers.

Q: Please describe the proposed ISO-NE 2015/2016-2017/2018 Winter Reliability Program.

A: Similar to the successful Winter Program II, the Winter Program III proposed by ISO-NE will include, among other things, compensation for unused fuel inventories. ISO-NE proposes to pay not only for incremental fuel inventory to oil-fired, dual-fuel, or LNG "take-or-pay" contract holders, but also to any other resource with on-site fuel storage, whether or not it is or would be incremental, or even if needed, in response to the Winter Reliability Program. Thus, ISO-NE proposed in the future to pay additional funds to resources that include nuclear, coal, biomass, and hydro. Furthermore, ISO-NE proposed to terminate eligibility for demand response services, and, based on the requirement of on-site fuel storage, its proposal would not include any incremental reliability payments to intermittent resources like wind and solar. As I see it, ISO-NE has proposed an interim program that is not resource neutral, and is not effectively comparable to a resource agnostic or market-based program.

Q: What is the objective of the 2015/2016-2017/2018 Winter Reliability Program?

A: Winter Program III has the same primary objective as Winter Programs I and II, that is, to ensure that certain resources procure *incremental* levels of fuel to support reliable operation of the electric system over the course of the winter seasons.[28]

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[28] *See Winter Reliability Solution: Committee Discussion*, presentation by Andrew Gillespie, Principal Analyst, Market Development, ISO-NE, March 10-11, 2015 NEPOOL Markets Committee, at Slide 7; *Winter Reliability Solution: Committee Discussion*, presentation by Andrew Gillespie, Principal Analyst, Market Development, ISO-NE, Jan. 13-14, 2015 NEPOOL Markets Committee, at Slide 7; *Winter Reliability Solution: Winter Periods Prior to June 1, 2018*, presentation by Andrew Gillespie, Principal Analyst, Market Development, ISO-NE, Nov. 11-12, 2014 NEPOOL Markets Committee, at Slide 6;

Q Does ISO-NE's proposal reflect a fuel neutral program?

A. No. Under its proposed approach, ISO-NE, by way of example, would favor nuclear and coal-fired resources over demand response, solar and wind resources. While both ISO-NE's and NEPOOL's proposals are expanded from a single winter to three winters, the ISO-NE program may not be as "expanded" as the name implies. ISO-NE has simply expanded the payments with what we perceive to be the same reliability benefits. Neither proposal is "resource neutral."

Q: Please describe the evolution of the Winter Reliability Programs from their inception to the current program, Winter Program III.

A: In Winter Program I, ISO-NE focused on filling the region's oil tanks to a level higher than resource owners were expected to in advance of the winter season.[29] ISO-NE accomplished this through an auction-based process, and ISO-NE paid selected resources their "as bid" price. In Winter Program II, ISO-NE expanded upon the program by including LNG "take-or-pay" contract holders, again to a level that resources were not expected to do on their own. More importantly, in Winter Program II, ISO-NE changed the basis for compensation from pre-season *total* inventory to an end-of-period *unused* inventory approach. ISO-NE fully justified this change and the Commission concluded that the revised program was just and reasonable. "By offsetting some (but not necessarily all) carrying costs of unused fuel, this compensation is intended to encourage generators to rely on upfront inventory rather than replenishment and to ensure that there is sufficient oil in on-site inventory to meet the region's needs in a cold winter."[30] Winter Program III, whether the ISO-NE Proposal or the NEPOOL Proposal, retains the unused inventory approach to compensation. The primary differences between these two

29 Ethier/Brandien Testimony at 17-18.

30 Testimony of Christopher Parent on Behalf of ISO New England Inc. (July 11, 2014), Docket No. ER14-2107 ("Parent Testimony"), at 10.

proposals are (i) the resource types that are eligible for compensation under the unused inventory provisions and (ii) associated cost implications of an expanded program, with the NEPOOL Proposal providing a similar level of reliability at a lower cost to the consumers who will pay for the program.

III. NEPOOL PROPOSAL

Q. Please describe the NEPOOL Proposal.

A. The NEPOOL Proposal largely mirrors Winter Program II, which the Commission approved and which ISO-NE concluded was successful in achieving the identified reliability benefits. The NEPOOL Proposal incorporates many of the conforming changes and updates to the program (*e.g.*, the payment rate for unused inventory will be updated consistent with the ISO-NE Proposal). In contrast to the ISO-NE Proposal, the NEPOOL Proposal maintains the same eligibility for resource types as reflected in the prior year's program, which is limited to oil-fired units (including dual-fuel), LNG contract holders, and demand response services.

Q. Please describe the genesis of the NEPOOL Proposal.

A. On behalf of NESCOE, I was a vocal and strong advocate for an alternative approach to the ISO-NE Proposal for consideration by NEPOOL, and found common ground with most of the NEPOOL market participants. At the beginning of the regional discussion about subsequent Winter Programs, while I was and intended to remain very active, ISO-NE appeared open to considering a variety of proposals and we did not anticipate NESCOE separately sponsoring a proposal. Once ISO-NE concluded it would move forward with its current proposal notwithstanding the views of NESCOE and other market participants, NESCOE developed an alternative consistent with its mission. One of the principles guiding this development was that the program used the prior winter was not broken and there was no need to set out to fix it.

Because the prior Winter Program had fully accomplished its objectives by delivering sufficient incremental reliability at a reasonable cost, NESCOE advocated for, and NEPOOL ultimately overwhelmingly approved, a proposal that was modeled largely after last year's Winter Reliability Program.

The NEPOOL Proposal updates the 2014/15 Winter Reliability Program with current payment rates for unused fuel inventories (including remaining LNG contract volumes) and other minor changes, importantly maintaining the same eligible resource types. In short, NESCOE proposed to continue the proven, effective, and efficient program that FERC approved, and that ISO-NE concluded had successfully provided the necessary level of incremental reliability to New England. The proposal NESCOE advocated in the NEPOOL process, which became the NEPOOL Proposal, was based on the common-sense, consumer-oriented observation that expanding program eligibility to some other resource types that were, as discussed below, unlikely or would not need to procure an additional level of fuel assurance in advance of the winter season would increase consumer costs unnecessarily without a corresponding or needed improvement to reliability.

Q. How would expanding eligibility for payments under the winter program, as ISO-NE proposes, raise consumer costs?

A. By expanding eligibility to other resource types, ISO-NE would apply the payment rate to a greater amount of unused fuel: in this case, unused fuel that would likely be present in New England without regard to any winter program. ISO-NE bases compensation for unused fuel inventory on a set payment rate that is applied consistently to those resources it has defined as eligible. The compensation rate is tied to the price of oil, expressed in dollars-per-barrel. So that ISO-NE can apply the payment rate to both oil-fired and other resource types, ISO-NE then converts the payment rate to a dollar-per-million-BTUs and dollar-per-megawatt hour rate, based on some assumed conversion factors. As the payment rate is, for all intents and purposes, a standard payment rate for all resource types ISO-NE declares to be eligible, expanding the base over which the rate applies necessarily would increase consumer costs.

Q. Has the increase in consumer costs associated with the ISO-NE Proposal relative to the NEPOOL Proposal been estimated?

A. I am not aware that ISO-NE performed an analysis of the different program costs during the stakeholder process. As part of my May 2015 presentation to the Markets Committee, I estimated the maximum exposure of each proposal under reasonable and consistent assumptions. The relative difference in the maximum exposure of each proposal provides an indication of the increase in consumer costs associated with ISO-NE's proposal to expand eligibility to other resource types. The table below, which is from the May 2015 presentation, calculates the cost difference using both last year's program rate of $18 per equivalent barrel and an estimated rate for the 2015/2016 winter of $14 per equivalent barrel.

Based on these calculations, using the expected $14 rate, I estimate the cost of the ISO-NE Proposal to consumers to be approximately $46 million per season more than the cost of the NEPOOL Proposal ($117.6 million vs. $71.51 million). This $46 million cost *difference* is almost equal to the *entire* cost of last year's program ($47.48 million) and more than double what the cost would have been last year under the expected $14 rate. *See* Table 1 below. The payment rate will be set separately just ahead of each of the next three years' winters, and the difference in cost between the proposals will be even larger if oil returns to prices used to calculate the 2014/2015 program rate.

TABLE I

Cost Comparison

	At Prior Year $18 Rate			In millions Max Cost Exposure			2014/2015
	Total MW*	Equiv BBL*	Payment rate	ISO-NE	NESCOE	EE&N	Actual
Nuclear	4041	1.62	$18	$29.16	$0.00	$0.00	$0.00
Coal	2002	0.8	$18	$14.40	$0.00	$0.00	$0.00
BioMass	577	0.23	$18	$4.14	$0.00	$0.00	$0.00
Hydro	2941	0.05	$18	$0.90	$0.00	$0.00	$0.00
Other	1500	0.6	$18	$10.80	$0.00	$0.00	$0.00
Oil	10778	4.1	$18	$73.80	$73.80	$0.00	$45.90
LNG	6 (BCF)	1	$18	$18.00	$18.00	$0.00	$1.50
DR**	-	-	-	$0.00	$0.11	$0.00	$0.08
EE&N Proposal	24000	-	$3	$0.00	$0.00	$216.00	$0.00
	Max Cost Exposure			$151.20	$91.91	$216.00	$47.48

	At Estimated $14 Rate			In millions Max Cost Exposure			2014/15
	Total MW*	Equiv BBL*	Payment rate	ISO-NE	NESCOE	EE&N	Actual
Nuclear	4041	1.62	$14	$22.68	$0.00	$0.00	$0.00
Coal	2002	0.8	$14	$11.20	$0.00	$0.00	$0.00
BioMass	577	0.23	$14	$3.22	$0.00	$0.00	$0.00
Hydro	2941	0.05	$14	$0.70	$0.00	$0.00	$0.00
Other	1500	0.6	$14	$8.40	$0.00	$0.00	$0.00
Oil	10778	4.1	$14	$57.40	$57.40	$0.00	$45.90
LNG	6 (BCF)	1	$14	$14.00	$14.00	$0.00	$1.50
DR**	-	-	-	$0.00	$0.11	$0.00	$0.08
EE&N Proposal	24,000MW	-	$3	$0.00	$0.00	$216.00	$0.00
	Max Cost Exposure			$117.60	$71.51	$216.00	$47.48

* Values per ISO-NE April MC slide presentation slide 14 ** DR price exposure based on highest cost to date.

At the $14 rate 2014/15 cost would have been ~$37M

Q. What is the significance of the increase in consumer costs associated with expanding program eligibility?

A. While the consumer costs of the Winter Reliability Programs must be considered in the context of providing important insurance against risks to reliable operation of the electric system resulting from natural gas pipeline constraints, the compensation provided to eligible resources must also be commensurate with the measure of additional reliability procured by the program. Consumers should only be made to pay incremental costs for the incremental value that has been proven to be needed.

Q. What is the objective of the NEPOOL Proposal?

A. Simply stated, the objective of the NEPOOL Proposal is to procure, as a stop-gap measure, an additional measure of reliability for the next three winters and to pay only for the incremental benefits and thereby limit the incremental reliability costs to consumers. As with prior Winter Reliability Programs, the NEPOOL Proposal is designed specifically to procure an *additional* level of fuel assurance from certain resources that otherwise would not have an adequate economic incentive to store the additional fuel inventory levels (or provide demand response services). The NEPOOL Proposal is specifically targeted to the resource types that can and have proven to provide measurable, verifiable, and truly incremental power system reliability through fuel assurance or demand response.

Q. How does the NEPOOL Proposal's design reflect the objective of procuring additional fuel ahead of winter?

A. The NEPOOL Proposal continues a proven and effective approach to ensuring fuel adequacy, one that FERC has found to be just and reasonable and not unduly discriminatory.[31] By limiting eligibility for incremental fuel payments to the natural gas- and oil-fired units most impacted by winter season natural gas transportation and supply constraints, the NEPOOL Proposal, like Winter Programs I and II that FERC approved earlier, provides "incentives for resources to procure more fuel than they would have procured in the absence of the program."[32]

Q. Why does the NEPOOL Proposal not provide incremental payments to other resource types?

A. Other resource types such as nuclear, coal, biomass, and hydro are not eligible for incremental compensation under the NEPOOL Proposal because there is no incremental benefit that has been identified by ISO-NE or anyone else that these resources are likely or able to provide beyond what they would have provided anyway, to support reliable operation of the electric system during the winter season. Nor has it been suggested that there is a need for any additional reliability benefit beyond the NEPOOL Proposal even if these resources were able to provide an incremental benefit. If these other resources are unlikely or unable to provide any

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[31] Winter Program II Order at P 43.
[32] *Id.*

additional fuel assurance, it is unclear how they would be providing an *incremental* measure of reliability. Without providing *additional* fuel assurance over the winter period, we cannot support including payments to these other resource types and imposing a corresponding increase in consumer costs. In short, consumers must receive value for the "reliability insurance" they are procuring through the winter program. Simply put, increased costs need to be accompanied by a measurable, needed incremental reliability benefit.

Consider, for example, the case of a nuclear unit. According to the Nuclear Energy Institute, "because nuclear plants refuel every 18-24 months, they are not subject to fuel price volatility like natural gas and oil power plants."[33] Moreover, nuclear units typically have limited ability to vary their electrical output and, due to low marginal costs, often operate at very high capacity factors for extended periods of time.

Q. Why did the previous Winter Reliability Programs exclude other resource types?

A. For the very same reason we have identified. According to ISO-NE, "in part, this is because the Winter Reliability Program is a fuel adequacy program, and it is difficult to identify additional fuel requirements for these types of resources, which typically have low-cost fuels or extended fuel supplies to meet their expected operation."[34]

Q. During the stakeholder process, did any market participants claim that other resource types were capable of providing *additional* reliability benefits?

A. Over the course of eight months of NEPOOL Markets Committee meetings, I am not aware of ISO-NE or any market participant offering any evidence of *additional* reliability benefits associated with ISO-NE's proposed expanded program eligibility. If market participants

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33 Nuclear Energy Institute, *Knowledge Center - Nuclear Statistics – Costs: Fuel, Operation, Waste Disposal & Life Cycle*, available at http://www.nei.org/Knowledge-Center/Nuclear-Statistics/Costs-Fuel,-Operation,-Waste-Disposal-Life-Cycle.

34 Parent Testimony at 9.

perceived *incremental* reliability benefits from compensating other resource types, they had an opportunity to put forth such information. To my knowledge and based on a review of meeting minutes, none did so nor did anyone suggest a need for any additional reliability benefit.

Q. Are there other differences between the NEPOOL Proposal and the ISO-NE Proposal?

A. Yes. The NEPOOL Proposal maintains eligibility for demand response services, while the ISO-NE Proposal does not. Parenthetically, this underscores the curiosity of ISO-NE advancing its proposal in the name of increasing resource neutrality. The ISO-NE Proposal is not resource neutral: it calls resources in-bounds and out-of-bounds just like its prior programs did. The differences between the NEPOOL Proposal and the ISO-NE Proposal are what resources are eligible and the program's overall price tag. Otherwise, the NEPOOL Proposal includes the same general terms and conditions (including the sunset date, March 15, 2018), auditing and performance requirements, and cost allocation provisions as the ISO-NE Proposal. In essence, the NEPOOL Proposal reinstates the prior year's successful resource type program eligibility with a limited number of conforming changes and updates.

IV. <u>NEPOOL PROCESS</u>

Q. Please provide an overview of the stakeholder process.

A. The 2015/2016-2017/2018 Winter Reliability Program was discussed at eight NEPOOL Markets Committee Meetings, from November 2014 to the vote in June 2015. At the May 2015 Markets Committee meeting, NESCOE presented the proposal labeled the "New England States' preferred approach". Before the next meeting, one NEPOOL market participants from *every* NEPOOL sector – a total of six – agreed to co-sponsor the NESCOE preferred approach. At the June 2015 Markets Committee meeting, the NESCOE preferred approach, referred to as the

Stakeholder Group proposal, garnered support from over 84% of the Markets Committee, effectively becoming the Markets Committee's recommendation to the Participants Committee. At the June 2015 NEPOOL Participants Committee summer meeting, the Stakeholder Group proposal received even more support with an 87.10% Vote in favor. This outcome resulted in the Stakeholder Group proposal becoming the NEPOOL Proposal.

Q. Please describe how support emerged for the NEPOOL Proposal.

A. Stakeholders in New England were already very familiar with Winter Program II. Over the course of the eight months of NEPOOL Markets Committee meetings, stakeholders expressed a variety of opinions on the need for another program, the merits of continuing the fundamental approach of Winter Program II, and concerns with ISO-NE's proposed expansion of the program once that was presented by ISO-NE. (I note that Winter Program II included an improved design relative to Winter Program I and provided a valuable measure of reliability insurance.) As stakeholders considered whether a "more market-based approach" was preferable or even feasible, the results of Winter Program II helped provide a benchmark on the performance of the system under the program during some of the coldest winter weather in recent history. NESCOE, along with other stakeholders, concluded that the proposal ISO-NE was then advocating was no more market-based than the Winter Program II, and were concerned that the additional costs of that proposal provided no identifiable benefits. NESCOE then presented the New England States' preferred approach that stakeholders coalesced around as a proven and effective program design. Stakeholders provided mostly supportive and positive comments on the initial NESCOE approach, suggesting certain changes that resulted in the Stakeholder Group, and ultimately, the NEPOOL proposal.

Q. Which market participants co-sponsored the proposal that was the alternative to ISO-NE's expanded program?

A. A market participant from each of the six NEPOOL sectors joined the proposal in support: Conservation Services Group (Alternative Resources Sector), TransCanada Power Marketing Ltd (Generation Sector), the Connecticut Office of Consumer Counsel (End User Sector), the United Illuminating Company (Transmission Sector), the Massachusetts Municipal Wholesale Electric Company (Publicly Owned Entity Sector), and Energy America, LLC. (an affiliate of Direct Energy) (Supplier Sector).

V. RECOMMENDATION

Q. Please summarize your recommendation.

A. I recommend that the Commission accept the NEPOOL Proposal. With overwhelming support from a majority of market participants in New England, consistent with consumer interests and the concerns raised by ISO-NE in its February 2015 Request for Rehearing, the NEPOOL Proposal continues a proven, effective and efficient program that continues to be a just and reasonable and not unduly discriminatory, and temporary, means of providing additional reliability during the winter season in New England.

Q. What is the primary rationale underlying your recommendation?

A. I am unable to identify any *incremental* reliability benefits associated with ISO-NE's proposed approach. Considering that expanded program eligibility will increase costs, but will provide no additional measure of reliability in return nor address any additional need over last year's program, I cannot support the ISO-NE Proposal. Thus, I view the best course of action to be maintaining a known and effective and reasonably priced interim solution.

Q. Please summarize why you view the NEPOOL Proposal as preferable to the ISO-NE Proposal?

A. The purpose of the Winter Reliability Program generally is to procure insurance against risks to reliability during the next three winters. Providing compensation for unused oil fuel inventory (and LNG contract volumes) and for demand response service achieves this objective. The additional costs associated with this temporary fuel assurance program are justified by the incremental reliability benefits provided by these resource types. The NEPOOL Proposal retains the resource types that made Winter Program II successful, rather than expanding eligibility and, in doing so, increasing consumer costs with no necessary or commensurate reliability benefit. Expanding program eligibility to resources that are unlikely or not needed to provide additional fuel assurance as ISO-NE proposes is not in the public interest for consumers in New England.

Q. Does this conclude your testimony?

A. Yes.

I declare, under penalty of perjury, that the forgoing is true and correct.

Executed on this 14th day of July, 2015.

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Jeffrey W. Bentz

ATTACHMENT N-1c

Testimony of John Flumerfelt

Director of Government and Regulatory Affairs, Calpine Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER15-___-000**
New England Power Pool	)	

TESTIMONY OF JOHN FLUMERFELT

Q. **What is your name and with whom are you affiliated?**

A. My name is John Flumerfelt. I am Director of Government and Regulatory Affairs for Calpine Corporation ("Calpine"), one of the nation's largest power producers and participants in regional wholesale power markets, where I have been employed for 15 years. Calpine's fleet includes 88 power plants in operation or under construction representing nearly 27,000 megawatts (MW) of installed electric generating capacity located throughout 18 states in the U.S. and in Canada. Calpine is the largest user of natural gas fuel in the electric power sector. My place of business is Falmouth, Maine.

Q. **Please describe your education and professional background**.

A. I have been directly involved in various aspects of energy policy and planning, natural gas and electric power project development, and electric power market design, for the past 30 years. Prior to joining Calpine, I served as Vice President of Granite State Gas Transmission, Inc., a pipeline subsidiary of Bay State Gas Company, where I managed state and local regulatory and public outreach efforts for development of Portland Natural Gas Transmission System and the proposed Wells LNG project. In that capacity, I served as a company witness before the Maine Public Utilities Commission and the Canada National Energy Board. Prior to joining Granite State, I served for three years as Maine's Director of Energy Policy and Planning under then-Governor John McKernan. Before relocating to New England, I worked in Washington, D.C. as Assistant Director for National Independent Energy Producers, and as Director of Congressional Relations for the National Association of Regulatory Utility Commissioners. I currently serve on the Board of Directors of New England Power Generators Association and as a member of the Board and the Executive Committee of Independent Power Producers of New York. I earned a BA in History from Hobart and William Smith Colleges in Geneva, New York.

Q. **Please describe any additional relevant experience for purposes of this proceeding**.

A. My primary responsibilities at Calpine include participation in stakeholder proceedings related to markets administered by the New York ISO ("NYISO"), and ISO-NE and I am a voting member of the Supplier Sector of New England Power Pool ("NEPOOL"). My role also includes related state regulatory and legislative representation, and I support Calpine's regional project development efforts as well as the company's various initiatives on competitive market design. My 30 years of experience related to a wide range of natural gas and power plant development and market issues gives me a thorough understanding of the dynamics of regional fuel and power markets.

Q. **What is the purpose of your testimony?**

A. The purpose of this pre-filed testimony is to explain why Calpine supports the NEPOOL jump ball alternative (the "NEPOOL Proposal") rather than the ISO New England proposal ("ISO-NE Proposal") to continue the Winter Reliability Program for the three winter periods prior to June 1, 2018. I believe my experience described above gives me the ability to provide an informed perspective regarding the competing Winter Reliability Program proposals before the Commission in this jump ball filing.

Q. **What is Calpine's overall position on the Winter Reliability Program?**

A. Calpine strongly prefers fuel neutral, market-oriented approaches rather than non-market solutions to address regional reliability needs. Indeed, Calpine promoted the idea of an auction-based incremental seasonal peaking product, with no restrictions on participant eligibility as part of the NEPOOL stakeholder discussions related to the initial development of the 2013-14 Winter Reliability Program. Other market participants have proposed market-based solutions as well. ISO-NE, however, requested latitude from the Commission to continue an out-of-market program for the next three winters, and the

Commission provided that requested latitude. As a result, subsequent NEPOOL discussions focused on alternative non-market approaches to winter reliability.

Calpine believes the region's experience over the past two winters shows that non-market programs have been successful in incentivizing generators to maintain sufficient regional fuel oil inventories and have thereby enhanced seasonal reliability. At the same time, Calpine believes that any non-market solutions in New England should be limited in scope and timing to the maximum extent possible.

Calpine strongly supports the concept of fuel neutrality in the context of a market-based solution, but we do not believe that simply including additional fuel types in a non-market solution results in a fuel neutral program. Moreover, the ISO-NE Proposal is not fuel neutral since it would *not* provide compensation to all resources that can support winter reliability, such as firm-delivered natural gas (other than that which is supplied by LNG) or potential power from imports. Thus, the ISO-NE Proposal is not consistent with Calpine's preference that non-market solutions be as narrow in scope as possible.

Additionally, Calpine believes that neither the NEPOOL Proposal nor the ISO-NE Proposal is likely to incentivize any substantial amount of additional seasonal LNG storage. Calpine offered an amendment during the NEPOOL stakeholder discussions to address this but was unable to garner support from ISO-NE or sufficient support from NEPOOL stakeholders, and it was not included in either alternative proposal. A description of the Calpine amendment, along with additional information regarding NEPOOL's consideration and Vote on that amendment, is provided in Section IV of NEPOOL's transmittal letter.

At the conclusion of the stakeholder process, Calpine was left with a choice as to whether to express a preference for one proposal over the other or simply to oppose both proposals. Given Calpine's overarching preference for a narrower rather than broader non-market alternative, Calpine strongly supports the NEPOOL Proposal as a preferable alternative to the proposal now being promoted by ISO-NE in this jump ball filing.

Q. Please summarize why Calpine supports the NEPOOL Proposal rather than the ISO-NE Proposal in this proceeding.

The NEPOOL Proposal is predicated upon and designed to maintain the core components of the 2014-2015 Winter Reliability Program approved by the Commission. The ISO-NE Proposal would expand the Winter Reliability Program to include participation of "Other Stored Fuels" – including water, coal, biomass, and nuclear fuel – while the NEPOOL Proposal would limit the program's applicability to fuel oil and LNG (and limited demand response). Calpine supports the NEPOOL Proposal over the ISO-NE Proposal because providing subsidies for these additional fuel types continues to fall short of being fuel neutral, and because the ISO-NE Proposal would not result in measureable incremental reliability benefits relative to the NEPOOL Proposal.

Q. Would you further explain why "Other Stored Fuels" should not be eligible for participation and compensation in the Winter Reliability Program?

A. There would be no reason to exclude other fuels or technologies if the program were a true market-based approach. But a non-market approach should be limited to measures that are cost-effective and actually promote meaningful incremental reliability.

The region's winter reliability exposure results primarily from a combination of seasonally constrained interstate natural gas pipeline capacity, and the fact that the existing market design does not adequately support the costs of maintaining robust inventories of typically more expensive fuel oil and LNG as a hedge against unusually severe weather conditions or other unexpected events. The existing program provides compensation to generators to encourage the purchase of incremental fuel supplies in an effort to ensure incremental reliability – compensation that is not obtainable under the existing market design. Given the region's experience over the past two winters, it is clear that the fuel oil component of the existing program has proven to be a cost-effective insurance policy that has helped maintain winter reliability.

The ISO-NE Proposal, however, would in some cases provide compensation for fuel that a generator already has purchased without the benefit of any subsidy. The most obvious example of this is including nuclear fuel in the program. It is difficult to see how providing a seasonal subsidy to baseload nuclear resources will have any impact on a nuclear power plant's fueling strategy or its ability to operate reliably during the winter. Providing additional compensation for behavior that generators undertake in the normal course of business is not necessary, is not cost-effective, and will not lead to any measureable increase in seasonal reliability.

The ISO-NE Proposal expands the program without being appropriately inclusive, and fails to ensure the market would get the additional reliability it would be paying for. The NEPOOL Proposal will achieve most, if not all, of the same reliability benefits without the extra cost.

Q. **What outcome does Calpine seek in this proceeding?**

A. Calpine strongly believes that the NEPOOL Proposal is the better pending jump ball option given that, absent a true market-based program, the NEPOOL Proposal is appropriately limited in scope and more targeted toward compensation that will promote incremental reliability. Accordingly, we urge the Commission to accept the NEPOOL Proposal as just and reasonable, and preferable to the ISO-NE Proposal.

Q. **Does that conclude your testimony?**

A. Yes.

I declare, under penalty of perjury, that the forgoing is true and correct.

Executed on this 13th day of July 2015.

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John Flumerfelt

ATTACHMENT N-1d

Testimony of Alan A. Trotta

Director of Wholesale Power Contracts, UIL Holdings Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER15-___-000**
New England Power Pool	)	

TESTIMONY OF ALAN A. TROTTA

Q. Please state your name and professional affiliation.

A. My name is Alan A. Trotta. I am Director of Wholesale Power Contracts for UIL Holdings Corporation ("UIL"), and I am a designated NEPOOL voting member for The United Illuminating Company ("UI"), UIL's electric utility, which is a member of the NEPOOL Transmission Sector.

Q. Please summarize your relevant professional background.

A. In my current position, I am responsible for all aspects of wholesale electricity procurement for UI. I am also responsible for leading UI's participation in NEPOOL and before the Federal Energy Regulatory Commission ("Commission") with respect to market-related matters. From 2003 through 2007, I worked at NSTAR Electric and Gas Corporation (now Eversource Energy), most recently as Manager of Power Resource Planning. Prior to working at NSTAR, I worked for El Paso Merchant Energy, most recently as a power trader. In addition to my experience with wholesale electricity, I have over a decade of experience in the natural gas industry in areas such as gas supply procurement, wholesale gas marketing and gas operations.

Q. On whose behalf are you filing this testimony and what is the purpose of your testimony?

A. While I am a UI representative, I prepared this testimony at NEPOOL's request to provide the Commission with UI's perspective on the Winter Reliability Program and explain why UI supports the NEPOOL Proposal over the ISO-NE Proposal.

Q. What position did UI and the Transmission Sector adopt at the Participants Committee meeting when voting on the Winter Reliability Program?

A. UI was a co-sponsor for the NEPOOL Proposal that overwhelmingly passed at the June 25, 2015 Participants Committee meeting, with a Vote of 87.10% in favor. UI supported the NEPOOL Proposal and opposed the ISO-NE Proposal. Likewise, the Transmission Sector unanimously supported the NEPOOL Proposal (with an abstention noted) and opposed the ISO-NE Proposal (with abstentions noted).[1]

Q. Does UI believe that the Winter Reliability Program is necessary?

A. Yes. The Winter Reliability Program is necessary, at minimum, to bridge the gap until ISO-NE's Pay for Performance capacity market rules take effect on June 1, 2018. The need for the Winter Reliability Program has been well documented by ISO-NE, and UI concurs with ISO-NE's assessment of the need.

Q. Why does UI support the NEPOOL Proposal instead of the ISO-NE Proposal?

There are two guiding principles behind UI's support of the NEPOOL Proposal and opposition to the ISO-NE Proposal. The first is UI's view that the Winter Reliability Program was established as a temporary, out-of-market solution to meet a specific reliability need, and as such any future application of an out-of-market Winter Reliability Program needs to remain limited in scope to exactly what's necessary to meet the reliability need – no more, no less. The second is UI's view that it is inappropriate to provide out-of-market compensation to an expanded pool of generation owners for doing exactly what they will already do in response to existing market signals. The expanded program eligibility (which ISO-NE argues reflects a fuel-neutral solution), and incremental compensation create a situation wherein an additional $40-50 million per

[1] *See* Attachment N-1g.

year[2] will be transferred from customers to certain generation owners with little or no improvement in reliability of energy supply.

The genesis of the Winter Reliability Program has been well documented in Docket Nos. ER13-1851 and ER14-2407. The problem that the Winter Reliability Program is designed to solve is essentially two-pronged. The first prong is physical in that the New England region's interstate gas pipeline infrastructure is not sufficient to serve the needs of both power generation and local gas distribution companies during peak winter conditions. When coupled with New England's high reliance on gas-fired generation, this has created a significant electric reliability challenge. The second prong is economic in that the current market design does not provide sufficient incentive for the purchase and retention of winter oil inventory by oil-fired generators, most of which are rarely dispatched in merit when conditions on the gas pipeline system are unconstrained. Until now, participation in the Winter Reliability Program has been appropriately limited to securing fuel inventory that can reasonably be deemed incremental to the region[3] in the form of oil purchases that would likely be otherwise uneconomic, liquefied natural gas (LNG) and incremental demand response.

Under the new ISO-NE Proposal, eligibility for compensation under the Winter Reliability Program would be expanded to include other resource types such as nuclear and coal generation. I am not aware of any credible evidence provided by ISO-NE or market participants that demonstrates that these types of resources would be expected to provide incremental fuel inventory to the region in response to program compensation. Rather, the most reasonable expectation is that these generators would be compensated for the same fuel that they would already be acquiring to ensure their participation in the energy market at anticipated high winter energy prices. In fact, it is commonly understood that nuclear resources typically refuel every 18 months or so during the periods of lower Fall and Spring demand. Since nuclear generators are already planning

[2] *See* Table 1 in Bentz Affidavit. The $40-50 million estimate is based on the $14 per barrel oil rate.

[3] While it can be argued that some of the oil and LNG purchases eligible under the current Winter Reliability Program would have been made anyway, the current market rules generally do not support the cost and risk associated with high levels of oil inventory or firm LNG purchase and delivery obligations.

for production at full capacity in the winter, it would be a stretch to believe that paying tens of millions of additional dollars to nuclear generators would produce any incremental firm fuel derived reliability benefit. It seems to me that the conflict between the NEPOOL Proposal and the ISO-NE Proposal generally boils down to whether eligibility is based on the provision of improved reliability derived from incremental firm fuel (NEPOOL), or on-site fuel, regardless of whether it provides incremental reliability (ISO-NE). Given that the program is a temporary, out-of-market solution, UI believes that the more limited NEPOOL eligibility is a just and reasonable solution and preferable to the ISO-NE Proposal.

The arguments for the ISO-NE proposal seem to center around fuel neutrality, and somehow equate a fuel neutral, out-of-market solution with a non-discriminatory market. While UI agrees that markets should be non-discriminatory, the Winter Reliability Program is not a market. Expanding eligibility for out-of-market payments does not somehow create a market where none existed, and does not solve any market discrimination. Indeed, the ISO-NE Proposal is no more market-based than the NEPOOL Proposal – it just sends more consumer dollars to more generators.

Q. What is UI specifically asking the Commission to do in this docket?

A. UI is asking the Commission to determine that, for a temporary out-of-market solution, the better outcome is the one that minimizes consumer costs by securing only incremental winter reliability for the region. The Commission should approve the Winter Reliability Program as proposed by NEPOOL, and as ratified by a Vote of 87.10% in support by the NEPOOL Participants Committee. The ISO-NE proposal should be rejected because it needlessly expands out-of-market compensation to resources without resulting in incremental winter reliability. UI's customers already bear a high cost for electricity during the winter months due in large part to gas pipeline constraints, and it would be inappropriate to layer on additional costs by paying extra for no reliability improvement under the expanded ISO-NE Proposal.

Q. Does that conclude your testimony?

A. Yes.

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

Alan A. Trotta

Executed on: July 8, 2015

ATTACHMENT N-1e

Affidavit of Brian E. Forshaw

Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER15-___-000**
New England Power Pool	)	

AFFIDAVIT OF BRIAN E. FORSHAW
NEPOOL PARTICIPANTS COMMITTEE
PUBLICLY OWNED ENTITY SECTOR VICE-CHAIR

I, Brian E. Forshaw, state as follows:

ABOUT ME

1. My name is Brian E. Forshaw. I am the Chief Regulatory and Risk Officer for the Connecticut Municipal Electric Energy Cooperative ("CMEEC"), a joint-action power supply agency organized pursuant to the Connecticut General Statutes to secure reliable and low cost power supplies for municipal electric utilities, where I have been employed for over 33 years. My place of business is 30 Stott Avenue, Norwich, Connecticut, 06360-1526.

2. My primary responsibilities at CMEEC include representing CMEEC and other Publicly Owned Entities[1] in matters before the New England Power Pool ("NEPOOL") and before various State and Federal regulatory and legislative forums. Additional responsibilities at CMEEC have included overseeing all aspects of CMEEC power supply and portfolio management activities, including risk management, long-term resource planning, strategic planning and contract negotiations.

3. In my over 33 years at CMEEC, I have directly participated, on behalf of New England's consumer-owned power systems, in virtually all of the efforts undertaken by NEPOOL and ISO-NE to restructure and refine New England's wholesale electric markets. This has included service on, among others, NEPOOL's Technical Committees and its Participants Committee. I am currently the elected representative of the Publicly Owned Entity Sector and serve as a Vice-Chair of the Participants Committee, an office I have held since 2002. I served as Chairman of

[1] Capitalized terms not defined in this Affidavit have the meanings ascribed thereto in NEPOOL's transmittal letter in this proceeding, the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff").

the Participants Committee for 2008 to 2009. It is with the benefit of these experiences and perspectives that I assess and evaluate in this affidavit the 2015-2018 Winter Reliability ("Winter Reliability") proposals before the Commission in this "jump ball" filing.

OVERVIEW

4. The purpose of my affidavit is to provide the Commission with CMEEC's perspective, which also represents the perspective of those members of the Publicly Owned Entity Sector that carried the unanimous vote of the Publicly Owned Entity Sector, regarding the two alternative Winter Reliability proposals being presented to the Commission in this proceeding. One of those proposals is supported overwhelmingly by the NEPOOL Participants (the "NEPOOL Proposal"). The second proposal (the "ISO-NE Proposal") is supported by ISO-NE and a handful of resource owners that will realize more revenues than they would under the NEPOOL Proposal, in our view without doing anything more for those revenues. The Commission is being asked in this proceeding to select which of these two proposals is preferable, and I would like to provide the Commission the perspective of CMEEC and the Publicly Owned Entity Sector more broadly as to why we unanimously supported the NEPOOL Proposal and opposed the ISO-NE Proposal.

5. Each of the 55 members of the Publicly Owned Entity Sector[2] is an Entity which is either a municipality or an agency thereof, or a body politic and public corporation created under the authority of one of the New England states, authorized to own, lease and operate electric generation, transmission or distribution facilities, or an electric cooperative, or an organization of any such entities. Publicly Owned Entities participate in New England's wholesale electric markets primarily to serve the needs of the residents of their municipality or the needs of its member municipal utilities, as the case may be.

6. Representatives of the Publicly Owned Entity Sector were involved in all discussions of the Winter Reliability proposals that occurred at NEPOOL's Principal Committees and expressed their views during those meetings. Indeed, the representative of the Massachusetts Municipal Electric Company ("MMWEC"), which is a key member of the Publicly Owned Entity Sector, co-sponsored the resolution considered by the Markets Committee to recommend

[2] A comprehensive list of the 55 members of the Publicly Owned Entity Sector and the 57 companies they represent can be found on NEPOOL's website at http://nepool.com/uploads/C-Sector_Roster.pdf.

NEPOOL Participants Committee support for the proposal that was ultimately approved by NEPOOL.

7. In the end, all the voting members of our Sector that participated in meetings to discuss this matter supported the proposal that ultimately became the NEPOOL Proposal. Members of the Publicly Owned Entity Sector, through their designated representatives, that were present for the Markets Committee votes on the Winter Reliability proposals unanimously supported the proposal ultimately approved by NEPOOL. Further, all opposed ISO-NE's Proposal. At the subsequent Participants Committee meeting, the Publicly Owned Entity Sector, again, unanimously supported the NEPOOL Proposal and opposed the ISO-NE Proposal.

8. I recognize that there may be other acceptable alternatives to the NEPOOL Proposal, but our Sector was most interested in finding a solution within the range of acceptable alternatives that was broadly supported in the region. Indeed, at one point during the Markets Committee deliberations, I personally developed a proposal that potentially would have been at an overall lower cost to consumers without compromising the benefits of the Winter Reliability programs being discussed. Under that proposal, which we elected not to pursue because it did not receive nearly the same level of broad support as the NEPOOL Proposal, there would have been fuel-specific compensation rates for each type of resource, rather than paying all resources at the equivalent oil rate; thereby reducing or eliminating incremental Winter Reliability program payments to resources that do not incur any increase in the carrying costs for their fuel inventory. The ISO-NE Proposal, in contrast, would pay resources such as coal, nuclear, and pumped hydro at the same rate as oil units, despite the fact that such resources would not incur any increase in carrying costs for their fuel inventory.

9. Finding a broadly acceptable solution in New England requires that many different interests be weighed and considered. Our preference for more targeted and differentiated compensation rates did not enjoy support from all six Sectors. It was more important to us here to find a solution that had broad support. The NEPOOL Proposal was that solution.

THE NEPOOL PROPOSAL IS FAR BETTER FOR THE REGION THAN THE ISO-NE PROPOSAL

10. Before comparing the NEPOOL Proposal to the ISO-NE Proposal, it is important to understand in greater detail why we supported a Winter Reliability program for the past two winters and agreed that an interim program is needed for the next three winters. In 2013, we

were persuaded by ISO-NE, as well as by studying experiences from the 2012-13 winter, that the region needed incremental fuel inventory beyond that already provided by the markets to back-stop against the potential limits of available natural gas resulting from limited pipeline capacity to the region. We agreed also that incremental demand response that reduced load when the system was most stressed during the winter could also provide an incremental reliability benefit. With that knowledge, we joined ISO-NE and much of the rest of NEPOOL in supporting the 2013-14 Winter Reliability program, which paid generators up-front to fill their fuel oil tanks, which also provided additional flexibility for dual-fuel generators to increase their energy revenues by arbitraging between their natural gas and fuel oil options, and finally which paid incremental demand response that was willing and able to interrupt during times of high winter need.

11. The experiences of the 2013-14 winter confirmed for us that some similar incentive also was needed during the next winter to provide incremental fuel inventory to guard against gas supply interruptions. At the same time, the prior winter's experiences suggested that a number of recently implemented or planned energy and reserve market enhancements were already providing higher revenue expectations in the market, which itself was providing incremental incentives for oil-fired generators to fill their tanks to operate on oil during the winter. Again with broad support across the region and by ISO-NE, the region adopted in 2014 a Winter Reliability program for the upcoming winter that would pay for the carrying costs of unused fuel oil inventory at the end of the winter rather than paying for such inventory up front. Further, the prior experience demonstrated that successful deployment of liquefied natural gas ("LNG") in the region was a comparable alternative to oil back-up in minimizing, if not avoiding, interruptions in pipeline gas to support the gas-fired generators. Thus, our Sector also unanimously supported expanding the Winter Reliability program to pay for unused portions of contracts entered into by generators for LNG to back-up their fuel supply. The demand response component from the prior winter helped in providing incremental reliability assurance so it, too, was broadly supported by our Sector for the 2014/15 winter.

12. Like the 2013/14 program, the program last winter had the intended effect. ISO-NE reported that market participants filled their fuel oil tanks going into the winter, which was what we desired, and contracts had been entered into for LNG back-up. Like the prior winter, some incremental demand response also was committed. As a result, reliability in the region was assured even though this past February was one of the coldest ones on record.

13. It is with these experiences (as well as consideration of further potential energy and reserve market design changes) that the region together explored what Winter Reliability program, if any, should be implemented for the next three winters before the ISO-NE's Pay-for-Performance ("PFP") capacity market becomes fully effective on June 1, 2018. While we certainly were willing to explore and consider, and did explore and consider, various market-based alternatives, all those alternatives would require major and prolonged implementation work with little or no perceived incremental benefit to the region when compared to the 2014/15 Winter Reliability program.

14. Following almost eight months of discussion and debate, and informed by litigation and Orders from the Commission, the region ultimately was confronted with two alternative proposals for consideration. Both of those alternatives were out-of-market solutions. ISO-NE decided, in my opinion because it made premature future commitments with respect to specifics of what it would present to the Commission, to be unyielding in its proposal to pay resources such as nuclear and coal simply because they had on-site fuel inventory. Rather than focus on the underlying objective for a Winter Reliability program in the first instance, which was broadly understood to provide ***incremental*** fuel inventory beyond that already provided by the markets, ISO-NE advocated simply to make incremental payments for any form of on-site fuel assurance during the winter. In so doing, it lost the historically broad support it had for the past Winter Reliability programs.

15. NEPOOL members agreed almost universally that the prior Winter Reliability programs succeeded in their objectives and were most interested in building off those successes. Working very closely with representatives of the New England States Committee on Electricity ("NESCOE") and other New England State entities, an alternative proposal was put forth that made only minor improvements to the successful 2014-15 Winter Reliability program. That alternative proposal, like the prior Winter Reliability programs, received extremely broad support across the pool. It ultimately was approved as the NEPOOL Proposal, with an 87.10% Vote of the Participants Committee and support from all six of the diverse Sectors in the region.

16. As noted, the Publicly Owned Entity Sector support for the NEPOOL Proposal was unanimous, as was its opposition to the ISO-NE Proposal. As the elected leader of that Sector, I certainly understood and support generally the desire to have market rules and markets that treat all similarly situated resources the same. Indeed, that was part of our rationale for supporting inclusion of LNG in the Winter Reliability program last winter and continuing in that support for

the remainder of the winters before transition to PFP. However, the region concluded together that the interim solution for the next three years was to be out-of-market, not market-based. From our Sector's standpoint, we prefer to minimize unnecessary out-of-market payments. Unfortunately, though, the ISO-NE Proposal expands out-of-market payments (and costs to consumers), and here it proposes to expand those payments to resources such as nuclear, coal, biomass, and hydro that are not providing incremental fuel inventory beyond those already provided by the markets.

17. Again, as we see the challenge for New England, we are relying very heavily on natural gas generation and are seeing limits particularly during maximum output by the gas pipelines during the winter months on how much natural gas can be transported to the gas plants on short notice. Fuel oil is a substitute, particularly for dual-fuel units, but actual experiences showed that the current market structure was not providing sufficient signals to maintain dual-fuel capability and high oil inventory. LNG certainly is also a substitute, but again actual experiences showed that the market was not providing enough economic incentive for generators to enter into LNG back-up arrangements for those potential circumstances where gas in the short term was not available because of pipeline limitations. Thus, we fully support the NEPOOL Proposal (and certainly those aspects of the ISO-NE Proposal that provide the same incentives).

18. We have seen no similar market signal shortcoming leading into and during the winter to support operations for nuclear, coal, biomass or hydro resources so that they would have fuel available when needed during the winter. Neither ISO-NE nor any advocate of the ISO-NE Proposal has provided any information suggesting otherwise. In our experience, the market works in a way that has nuclear resources planning refueling outages for times when load and prices are low, thereby seeking to maximize their energy market revenues. We can see no way that making an out-of-market payment to nuclear plant operators following each winter will change their behavior in any way.

19. Similarly, looking at coal, the current market, as we understand it, supports maintaining coal inventories during times of high energy prices. There are unquestionably environmental factors impacting coal units but we have not understood any element of the regional winter challenges to be driven by decisions of coal units not to stock their coal piles. Those fuel inventories, as we understand it, generally support months, not hours or days of operation like gas plants or oil plants.

20. So too with biomass as we understand those operations and we have not heard any argument in support of biomass requiring such incremental out-of-market revenues to be available when needed during the winter.

21. For the hydro units, the particular units we understand that would be eligible to receive out-of-market payments under the ISO-NE Proposal would be pumped-storage units. CMEEC had an entitlement in such a unit in the past, and that unit was operated to cycle between its fill and draw times each day in order to maximize its net energy revenues on a daily basis and over the course of a weekly dispatch cycle. Thus, the plant would generate energy during the peak hours of load each day, and would pump water to replenish the upper reservoir at night and during weekends when load and energy prices were down. Given my knowledge and experiences, I fail to see how incremental out-of-market payments to these units at the end of each of the next three winters will impact in any way how or when these units operate during the winter.

22. In short, we see the ISO-NE Proposal requiring consumers to pay nuclear, coal, biomass and certain hydro units substantial additional monies that will not have any material benefit to reliability or operations for the winter. The additional out-of-market payments would, in our view, have these resources doing nothing more than they would do without any Winter Reliability program. We see such incremental payments as simply unjustified and imposing these incremental costs on consumers as unreasonable.

23. In contrast, the NEPOOL Proposal adopts a more narrow approach to address targeted problems underlying reliability during winter months. The NEPOOL Proposal seeks to utilize programs that have already proven successful during the past winter, without subjecting the region to the substantially increased costs (and no corresponding benefit).

24. Those were the reasons the Publicly Owned Entity Sector unanimously supported the NEPOOL Proposal and unanimously opposed the ISO-NE Proposal. I submit that those are the same reasons that the Commission should select the NEPOOL Proposal as the preferable alternative to the ISO-NE Proposal.

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

Brian Forshaw

Brian E. Forshaw

Executed on: July 15, 2015

ATTACHMENT N-1f

Affidavit of Herb Healy

Senior Director of Regulatory Affairs, EnerNOC, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER15-___-000**
New England Power Pool	)	

AFFIDAVIT OF HERB HEALY

I, Herb Healy, state as follows:

1. Since June of 2007, I have been employed as Senior Director of Regulatory Affairs for EnerNOC, Inc., ("EnerNOC") a provider of energy management services that includes delivering demand response ("DR") services as a curtailment service provider. I am currently responsible for EnerNOC's regulatory affairs in the northeast part of the U.S, Canada, Ireland, and the United Kingdom. In that role I am responsible for EnerNOC's activities in ISO New England Inc. ("ISO-NE"), serving as EnerNOC's primary voting member in numerous NEPOOL committees and subcommittees. My experience in the electricity industry spans a career of 48 years. Prior to my employment with EnerNOC, I was employed by United Technologies Corporation beginning in 1968, in their Power Systems division (and predecessor groups) which was focused on development of new electrical power generation technologies, particularly fuel cells. Through my work for EnerNOC and participation in ISO-NE, I have first-hand knowledge of the role of DR in the ISO-NE markets.
2. The purpose of my affidavit is to provide the Commission with the view of DR providers in NEPOOL's Alternative Resources sector ("AR Sector") regarding the two Winter Reliability Program proposals for the next three winters (the "ISO-NE

Proposal" and "NEPOOL Proposal"), that are before the Commission in this "jump ball" filing.

3. EnerNOC is a NEPOOL Participant and a member of the NEPOOL AR Sector. The AR Sector is comprised of Participants with substantial business interests in Demand Response Resources and Energy Efficiency Resources, Distributed Generation ("DG") Resources, and/or Renewable Generation Resources.[1]
4. EnerNOC is, and has been, a leading DR provider across the globe and in New England for several years.
5. As the Commission has recognized, DR plays an important role in helping to maintain reliability and to lower prices to consumers during periods of peak demand, system constraints and supply resource scarcity, which are precisely the kinds of conditions that the winter reliability program is intended to address.
6. EnerNOC actively participated in the NEPOOL stakeholder processes to develop the past two Winter Reliability Programs. EnerNOC supported the 2013-2014 Winter Reliability Program proposal that the Commission approved, as did the rest of the AR Sector. EnerNOC's past support of the program was based in large part on the inclusion of DR in the set of eligible resources.
7. During the stakeholder process, the AR sector opposed the ISO-NE Proposal. The AR sector unanimously supported the NEPOOL Proposal (with an abstention noted).[2]
8. There are three primary reasons for EnerNOC's opposition to the ISO-NE Proposal:
    a. First, the ISO-NE Proposal would exclude DR from participation in its

[1] All as defined in the Second Restated NEPOOL Agreement.

[2] *See* Attachment N-1g.

proposed Winter Reliability Program through one of its eligibility criteria, thereby unnecessarily precluding participation by a whole category of valuable resources. ISO-NE's two key criteria proposed for participation in the upcoming Winter Reliability Program are (1) that resources must be dispatchable, which criterion DR meets, and (2) that participating resources have on-site fuel capability, which criterion DR cannot meet because it is a demand-side resource that does not require fuel. ISO-NE could have designed its program to be open to all dispatchable resources with on-site fuel, and to DR, but it chose not to do so. Excluding DR from the Winter Reliability Program covering the next three winter periods is irrational based on past history, would make the program less resource diverse, and is unfair as it would unduly discriminate against DR.

DR has already proven itself in the past two Winter Reliability Programs to be a valuable contributing resource when called upon. During both of those Winter Reliability Programs, DR was not only eligible to participate, but was awarded a contract, and contributed toward winter regional reliability. The DR that participated in those programs was incremental DR to any DR with an obligation in the Forward Capacity Market ("FCM"). Importantly, the contracted DR was dispatched in each of the two winter periods and its performance in each dispatched event exceeded its Winter Reliability Program commitment. Accordingly, DR has already proven it is a viable incremental resource that has contributed to ensuring reliability during the past two winters, in addition to the value it provides as an FCM resource.

Additionally, the 3-year duration of the ISO-NE Proposal compounds the adverse effect on DR. Unlike the previous Winter Reliability programs that were effective only for one year, the ISO-NE Proposal covers the next three winter periods. This 3-year period provides a more investible basis for DR participation than a single year program; i.e., there are up-front costs for new DR to participate and the lack of continuity in the previous 1-year programs was a significant disincentive to enrollment. By contrast, the 3-year program duration would provide an additional incentive to DR and increase DR's potential participation and reliability benefit to New England at the same time that the ISO-NE Proposal makes DR ineligible.

b. Second, EnerNOC agrees with the analysis of the New England States Committee on Electricity ("NESCOE"), of the costs and benefits of the ISO-NE Proposal, and submits that the proposed change to expand last year's program to other types of generation resources does not make sense. The ISO-NE Proposal will incur incremental costs for resources without receiving incremental benefits, due to the expansion of the program to resources that will require no additional efforts or costs to secure fuel for the winter. While EnerNOC appreciates the motivation for a winter program that is technology agnostic, ISO-NE has not proposed such a program and expanding the program to include resources that consume more types of fuel (i.e., more "fuel neutral") will, in my view, result only in incremental costs being incurred without receipt of incremental benefits, especially when the program is just an interim program.

c. Third, implementing the ISO-NE Proposal raises a concern about ISO-NE internal resource allocation. ISO-NE has limited internal resources that it can allocate to market design development and implementation. Were the Commission to approve ISO-NE's proposal, ISO-NE would be required to undertake additional design and implementation efforts for a new winter reliability program that will only be in effect for three winters, despite the fact that last year's program worked well. The diversion of ISO-NE resources to accomplish this change means that other market design and implementation efforts, including those affecting AR sector members including DR, DG and/or Renewable generation resources, will likely be adversely impacted. EnerNOC does not support any diversion of scarce ISO-NE resources, especially for a program that unnecessarily excludes DR.

9. DR providers support the NEPOOL Proposal largely because the NEPOOL Proposal avoids the above-listed problems and continues a program that has demonstrated success. The Commission should allow DR to participate in any Winter Reliability Program, and not force New England to incur incremental costs with no incremental benefit, and waste scarce ISO-NE resources on implementation of a new program.

10. EnerNOC does not view the NEPOOL Proposal as the only way for the region to address winter reliability issues. However, there is no reason to exclude DR from participating in a program to address winter reliability.

11. For all of these reasons, EnerNOC opposes the ISO-NE Proposal and supports the NEPOOL Proposal.

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

Herb Healy

Executed on: July 2, 2015

ATTACHMENT N-1g

Tabulation of NEPOOL Participants Committee Votes Taken on the ISO-NE and NEPOOL Proposals

JUNE 25, 2015 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON
WINTER RELIABILITY PROGRAM
FOR WINTER PERIODS PRIOR TO JUNE 1, 2018

TOTAL

Sector/Group	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
GENERATION	10.28	7.34	11.41
TRANSMISSION	8.56	17.12	0.00
SUPPLIER	11.85	14.01	2.02
ALTERNATIVE RESOURCES	10.79	14.37	0.00
PUBLICLY OWNED ENTITY	0.00	17.12	0.00
END USER	8.11	17.12	0.00
PROVISIONAL MEMBERS	0.02	0.02	0.00
% IN FAVOR	**49.61**	**87.10**	**13.43**

GENERATION SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Dominion Energy Marketing, Inc.	O	O	F
Entergy Nuclear Power Marketing	A	O	F
Essential Power, LLC	F	F	A
GDF SUEZ Energy Marketing NA	F	O	F
Generation Group Member	A	A	A
NextEra Energy Resources, LLC	O	O	F
NRG Power Marketing, LLC	A	A	A
TransCanada Power Marketing	A	F	O
Verso Maine Energy LLC	F	F	O
IN FAVOR (F)	3	3	4
OPPOSED (O)	2	4	2
TOTAL VOTES	5	7	6
ABSTENTIONS (A)	4	2	3

TRANSMISSION SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Central Maine Power Company	A	F	A
Emera Maine	F	S[1]	S[1]
Emera Maine	-	F	O
Emera Energy Services Subsidiaries	-	A	A
Eversource Energy	O	F	A
National Grid	O	F	A
The United Illuminating Company	F	F	O
Vermont Electric Power Company	A	F	O
IN FAVOR (F)	2	5.5	0
OPPOSED	2	0	2.5
TOTAL VOTES	4	5.5	2.5
ABSTENTIONS (A)	2	0.5	3.5

ALTERNATIVE RESOURCES SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Renewable Generation Sub-Sector			
Jericho Power LLC	O	F	O
SunEdison (First Wind)	A	A	O
Small RG Group Member	F	F	O
Distributed Generation Sub-Sector			
Conservation Services Group	A	F	O
Load Response Sub-Sector			
EnerNOC, Inc.	F	F	O
VT Energy Investment Corp.	A	F	O
Small LR Group Member	A	F	O
IN FAVOR (F)	2	6	0
OPPOSED	1	0	7
TOTAL VOTES	3	6	7
ABSTENTIONS (A)	4	1	0

SUPPLIER SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
BP Energy Company	A	F	O
Brookfield Energy Marketing/CSC	O	O	O
Calpine Energy Services	F	F	O
Competitive Energy Services, LLC	F	F	O
Consolidated Edison Energy, Inc.	F	A	O
DTE Energy Trading, Inc.	O	F	O
Dynegy Marketing and Trade, LLC	F	O	F
Energy America, LLC	O	F	O
Exelon Generation Company	F	A	A
Galt Power, Inc.	A	F	O
Granite Ridge/ Merrill Lynch Commodities	F	A	F
H.Q. Energy Services (U.S.) Inc.	A	A	A
LIPA (Long Island Power Authority)	A	F	O
Marble River, LLC	A	A	O
PSEG Energy Resources & Trade	F	F	O
Repsol Energy North America	F	A	O
South Jersey Energy Company	O	F	O
Texas Retail, LLC	F	A	O
Vitol Inc.	A	A	O
IN FAVOR (F)	9	9	2
OPPOSED	4	2	15
TOTAL VOTES	13	11	17
ABSTENTIONS (A)	6	8	2

[1] Pursuant to Section 6.2 of the NEPOOL Agreement, Participants and their Related Persons are for voting purposes together permitted to join only one Sector to which any of them is eligible to join, but are permitted to split the vote in that Sector as they see fit. Emera Maine and the Emera Energy Services Subsidiaries, as Related Persons, are collectively members of the Transmission Sector, but sometimes split their vote evenly between the companies' transmission (Emera Maine) and generation (Emera Energy) interests.

JUNE 25, 2015 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON
WINTER RELIABILITY PROGRAM
FOR WINTER PERIODS PRIOR TO JUNE 1, 2018

END USER SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Conn. Office of Consumer Counsel	O	F	O
Elektrisola, Inc.	F	F	O
Fairchild Semiconductor Corp.	F	F	O
Harvard Dedicated Energy Limited	O	F	O
High Liner Foods (USA) Inc.	F	F	O
Industrial Energy Consumer Group	O	F	O
Maine Public Advocate Office	O	F	O
Maine Skiing, Inc.	O	F	O
Mass. Attorney General's Office	O	F	O
MoArk, LLC	F	F	O
NH Office of Consumer Advocate	O	F	O
PowerOptions, Inc.	O	F	O
St. Anselm College	F	F	O
Shipyard Brewing Co., LLC	F	F	O
The Energy Consortium	O	F	O
Union of Concerned Scientists	F	F	O
Westerly Hospital	F	F	O
Z-TECH, LLC	F	F	O
Utility Services Inc.	O	F	O
IN FAVOR (F)	9	19	0
OPPOSED	10	0	19
TOTAL VOTES	19	19	19
ABSTENTIONS (A)	0	0	0

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Ashburnham Municipal Light Plant	O	F	O
Boylston Municipal Light Dep't	O	F	O
Belmont Municipal Light Dep't	O	F	O
Chester Municipal Light Dep't	O	F	O
Chicopee Municipal Lighting Plant	O	F	O
Concord Municipal Light Plant	O	F	O
Conn. Mun. Electric Energy Coop.	O	F	O
Danvers Electric Division	O	F	O
Georgetown Municipal Light Dep't	O	F	O
Groton Electric Light Department	O	F	O
Groveland Electric Light Dep't	O	F	O
Hingham Municipal Lighting Plant	O	F	O
Holden Municipal Light Dep't	O	F	O
Holyoke Gas & Electric Dep't	O	F	O
Hudson Light and Power Dep't	O	F	O
Hull Municipal Lighting Plant	O	F	O
Ipswich Municipal Light Dep't	O	F	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Littleton (MA) Electric Light Dep't	O	F	O
Littleton (NH) Water & Light Dep't	O	F	O
Mansfield Municipal Electric Dep't	O	F	O
Marblehead Municipal Light Dep't	O	F	O
Mass. Development Finance Agc'y	O	F	O
Mass. Mun. Wholesale. Elec. Co.	O	F	O
Merrimac Municipal Light Dep't	O	F	O
Middleborough Gas & Elec. Dep't	O	F	O
Middleton Municipal Electric Dep't	O	F	O
New Hampshire Electric Coop.	O	F	O
Pascoag Utility District	O	F	O
Paxton Municipal Light Dep't	O	F	O
Peabody Municipal Light Plant	O	F	O
Princeton Municipal Light Dep't	O	F	O
Rowley Municipal Lighting Plant	O	F	O
Russell Municipal Light Dep't	O	F	O
Shrewsbury's Elec. & Cable Ops.	O	F	O
South Hadley Electric Light Dep't	O	F	O
Sterling Mun. Elec. Light Dep't	O	F	O
Stowe (VT) Electric Department	O	F	O
Taunton Municipal Lighting Plant	O	F	O
Templeton Mun. Lighting Plant	O	F	O
VT Electric Cooperative	O	F	O
VT Public Power Supply Authority	O	F	O
Wakefield Mun. Gas & Light Dep't	O	F	O
Wallingford (CT) Div. Pub. Utils.	O	F	O
Wellesley Municipal Light Plant	O	F	O
West Boylston Mun. Lighting Plant	O	F	O
Westfield Gas & Elec. Light Dep't	O	F	O
IN FAVOR (F)	0	46	0
OPPOSED	46	0	46
TOTAL VOTES	46	46	46
ABSTENTIONS (A)	0	0	0

PROVISIONAL MEMBERS

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Tangent Energy Solutions, Inc.	F	F	A
IN FAVOR (F)	1	1	0
OPPOSED	0	0	0
TOTAL VOTES	1	1	0
ABSTENTIONS (A)	0	0	1

ATTACHMENT N-1h

Blacklined Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective September 14, 2015

APPENDIX K

WINTER RELIABILITY SOLUTIONS

WINTER RELIABILITY SOLUTIONS

III.K.1. General~~Purpose and Sunset~~.

(a) **Term.** This Appendix K ~~e ISO~~ is intended ~~providing incentives for the four services described in this Appendix K in order~~ to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.

(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; modeled in the EMS; and either (i) dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.

(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.

(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.

(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.

(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 and III.K.3 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Notwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.

(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas. The Set Rate for the demand response service in Section III.K.4 shall be calculated as follows:

$$\text{DR Set Rate} = R_o \times [(1/H_{avg}) \times HR_g \times 100MW \times 180_h]/(100{,}000\ kW \times 3\ months)$$

Where:

R_o: Oil program Set Rate in $/bbl

H_{avg}: MW-Weighted average heat content of oil-fired units in New England = 6.0 MMBtu/bbl

HR_g: Generic heat rate = 10 MMBtu/MWh

180_h: 180 hours, which is the maximum number of hours a demand response asset could be dispatched during the winter

(h) **Conflict.** Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.

III.K.2. Oil Fuel.

Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

~~The services are: (a) establishment of oil inventory by Generator Assets prior to December 1, (b) establishment of liquefied natural gas contracts by Generator Assets prior to December 1, (c) commissioning of dual-fuel capability by Generator Assets on or before December 1, 2016, and (d) additional reductions in demand and/or provision of net supply by demand response assets during the winter.~~

~~This Appendix K sets out a process for Market Participants to provide one or more of these services, and the terms and conditions on which the services must be provided.~~

~~Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents. Unless extended, this Appendix K, other than Section III.K.5, shall expire on March 15, 2015, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein. Section III.K.5 shall expire on December 1, 2016.~~

~~**III.K.2. Eligibility and General Requirements.**~~

~~Only Market Participants may provide the services described in this Appendix K. Participating Generator Assets must be modeled in the EMS and dispatchable as described in Operating Procedure #14. Regardless of whether they have a Capacity Supply Obligation, Market Participants providing services under Sections III.K.3 and III.K.4 must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the winter. Market Participants may not sell the fuel (or fuel rights) described in Sections III.K.3 through III.K.5 during the period in which they are obligated (which extends through and including the winter of 2017 for Generator Assets providing the dual fuel service described in Section III.K.5), or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K. To participate in one or more of the services, a Market Participant must notify the ISO by October 1 (or, in the case of the dual fuel commissioning service described in Section III.K.5, December 1, 2014) and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset.~~

Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety-fill and structural limitations. Tanks removed from service due to structural damage or for long-term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.

~~**III.K.3. Oil Fuel Service.**~~

~~Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.~~

(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil. ~~will demonstrate, their ability to run on oil. Generator Assets that share a fuel supply may participate only if all Generator Assets sharing the fuel supply participate, in which case the oil inventory levels described below will be calculated in the aggregate; provided that the ISO may exempt one or more Generator Assets from the requirement that all Generator Assets sharing a fuel supply must participate if the ISO determines at the beginning of the winter period that the Generator Asset(s) are reasonably expected to be out of service for the winter period.~~

(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.~~2~~1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.2~~3~~(d). The December 1 inventory level will be deemed to include: ~~(x)~~ oil that the ISO determines was burned to produce electricity on and after November 15 of that year, including during ~~; and (y) a credit for oil that was burned in~~ an audit of dual fuel capability ~~occurring on or after November 15~~, provided that ~~the~~ oil used in an~~the~~ audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.2~~3~~.

~~(c) **Measuring Inventory.** Participating Generator Assets must report their usable oil inventory levels to the ISO on the first of the month during the winter and as otherwise requested by the ISO.~~

~~(d)~~(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K. 2~~3~~(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10~~15~~ days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. ~~Set Rate shall mean $18/barrel.~~ Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.3~~4~~. Liquefied Natural Gas ~~Service~~.

Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of thate~~e~~ winter.

(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving ~~both~~ pipeline gas ~~and~~ or supplies of liquefied natural gas.

(b) **Proposed Contracts.** In the notice specified in Section III.K.~~2~~1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.3~~4~~. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.~~4~~3(c). The ISO will review the notices and ~~provide notice~~ inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.3~~4~~(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a "first come/first served" basis and shall inform Generator Assets of their provisional acceptance by each October 15.

(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a "take-or-pay" construct; the volume specified by the Market Participant pursuant to Section III.K.3~~4~~(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO's provisional acceptance will be withdrawn.

~~(d) **Measuring Use.** Participating Generator Assets must report their remaining contracted volumes to the ISO on the first of the month during the winter and as otherwise requested by the ISO, and provide other supporting documentation as required.~~

~~(e)~~(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:

(Unused Quantity x Set Rate) x Performance Adjustment

Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. ~~The Set Rate shall mean $3.00/MMBTU.~~ Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

III.K.~~6~~4. Demand Response Service.

All defined terms used in this Section III.K.~~6~~ 4 shall have the same meanings as if the asset were a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Market Participants with an asset located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including an asset with behind-the-meter generation capable of reducing demand from the electric system and delivering any net supply, are eligible to participate pursuant to this Appendix K. Assets mapped to a Real-Time Demand Response Resource are eligible to participate, subject to the additional requirements specified below, and provided that the capacity supplied by these assets is in addition to the Capacity Supply Obligation, as of December 1 of the relevant Capacity Commitment Period, of the Real-Time Demand Response Resource to which the asset is mapped, and provided further that the prohibitions in Section III.E1.1.2 are not triggered.

Except for assets mapped to a Real-Time Demand Response Resource, an asset may consist of an aggregation of individual end-use facilities so long as those facilities are located within the same Dispatch Zone, and provided further that such aggregation does not result in a quantity of demand reduction and net supply of 5 MW or greater at a single Node.

The following asset types are not eligible to provide services under this Section III.K.~~5~~4: (i) Real-Time Emergency Generation Assets; (ii) any asset that is dependent upon a non-firm or an additional supply of natural gas to produce demand reductions or net supply; and (iii) any asset that participates in the energy market pursuant to Section III.1 of the Tariff.

Each Market Participant that has an asset accepted by the ISO for this service is subject to the following additional requirements from the relevant December 1 through March 1:

(a) **In service.** By December 1, participating assets must, in accordance with the existing requirements for Real-Time Demand Response Assets and Real-Time Emergency Generation Assets: (i) be registered with the ISO; (ii) have meters installed and operational; (iii) have a valid Demand Response Baseline; (iv) have a Demand Designated Entity to which Dispatch Instructions are communicated; and (v) otherwise be fully ready to respond.

(b) **Size of Program and Assets.** Each participating asset shall provide at least 100 kW of capability. No more than 100 assets at a level not to exceed 100 MW shall be accepted by the ISO pursuant to this Appendix K.

(c) **Metering.**

i. Market Participants must meet the metering requirements specified in Appendix III.E and the ISO New England manuals, with the exception that 5-minute meter data does not have to be reported to the ISO in real time for assets not mapped to a Real-Time Demand Response Resource.

ii. To the extent that an asset consists of an aggregation of individual end-use facilities, Market Participants must submit a single set of interval meter data, as measured from each facility's Retail Delivery Point, representing the sum of the metered demand of the end-use facilities comprising the asset.

iii. Market Participants shall report meter data and may submit meter data corrections to the ISO using the Demand Response Market User Interface within 2.5 business days after the Operating Day.

iv. Meter data corrections may be submitted during the 70-day period beginning with the first of the month following the operating month. To the extent meter data affecting an asset's performance measurement and passing all quality checks has not been submitted by the initial settlement deadline (i.e., within 2.5 business days after the Operating Day), payments related to that asset shall be deferred to the resettlement process.

v. In the event that valid meter data affecting an asset's monthly performance measurement that passes all quality checks is not submitted by the end of the 70-day data correction limit, that asset's performance shall be deemed to be zero for the intervals for which the meter data did not pass all quality checks.

(d) **Dispatch.**

i. Assets must be available for dispatch in real time between hours ending 0600 and 2300 on all days.

ii. Each dispatch shall be for no more than six hours.

iii. There will be no more than two dispatches per asset per day.

iv. There shall be at least four hours between the end of one dispatch and the start time of another dispatch.

v. Assets will be dispatched by the ISO at its discretion prior to, or concurrent with, ISO New England Operating Procedure No. 4, Action 2. The ISO may aggregate assets into blocks and dispatch only those assets comprising the blocks.

vi. Each asset shall be required to respond to Dispatch Instructions no more than thirty times.

vii. The ISO will communicate Dispatch Instructions to the Demand Designated Entity specified by the Market Participant for each participating asset.

viii. Assets will be dispatched for their entire, committed MW quantity except in cases where such dispatch may cause or worsen a local reliability problem. The ISO may, upon notification to the Demand Designated Entity, exclude from dispatch assets located in a particular Dispatch Zone, and/or individual assets where the committed MW quantity is 5 MW or more.

ix. Except as outlined in viii. above, assets must produce the MW quantity accepted pursuant to this Appendix K within thirty minutes of the issuance of a Dispatch Instruction.

x. If assets mapped to a Real-Time Demand Response Resource are dispatched pursuant to this Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource, and the amount of demand reduction plus any net supply produced in that interval is less than the Real-Time Demand Response Resource's Capacity Supply Obligation plus the sum of the asset's committed MW quantity pursuant to Appendix K, the amount of demand reduction plus any net supply produced shall be credited first to the Real-Time Demand Response Resource's Capacity Supply Obligation and the remainder shall be credited pro-rata to each asset with an obligation pursuant to Appendix K based on asset performance.

(e) **Acceptance Criteria.** Market Participants must indicate their commitment to provide this demand response service by providing the notice indicated in Section III.K.~~2~~1(e). That notice must include: the name and other pertinent identifiers of the asset that the Market Participant is seeking to enroll, the asset's electrical location, the MW quantity of demand reduction and any net supply, as measured from the asset's Retail Delivery Point, that the asset is willing and able to produce in response to Dispatch Instructions, and the method(s) by which the demand reduction or any net supply would be produced. If the Market Participant has not yet identified all of the assets that will be recruited to meet the service requirements, the Market Participant shall provide a description of how it will meet the requirements, and provide the Dispatch Zone within which these assets will be located. If an asset specified in the notice consists of an aggregation of individual end-use facilities, the information shall be provided for each facility that is part of the aggregation. The ISO shall accept up to 100 qualified assets at a level not to exceed 100 MW from those Market Participants providing notice, based on:

i. The asset's proposed capacity;

ii. The asset's location relative to known constrained areas; and/or

iii. Any historic performance from the asset.

The ISO may accept or reject any and all assets proposed for participation.

(f) Compensation.

a. **Monthly Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall be compensated under this Appendix K through a monthly payment of ~~$1,800~~the Set Rate multiplied by the average MW performance achieved by the asset in the month, provided that such MW performance shall not exceed 150% of the committed MW quantity. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If the asset was not dispatched or audited in the month of December, the payment for that asset for that month will be based on its average MW performance in response to dispatch (including a dispatch for an audit) in the following month. If an asset was not dispatched in January or February, but was dispatched or audited in a previous month, the asset's payment for the month in which it was not dispatched will be based on its average MW performance in the most recent month in which the asset was dispatched or audited.

b. **Monthly Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter, ~~T~~the monthly payment for assets that are mapped to a Real-Time Demand Response Resource will be the Set Rate ~~$1,800~~ multiplied by the average MW performance achieved by the asset in the month not to exceed 100% of the committed MW quantity, and further multiplied by the Performance Factor. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If an asset is dispatched in a month pursuant to Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource to which it is mapped, a Performance Factor will be calculated as follows:

$$\textit{Performance Factor} = \frac{\textit{(Average Hourly FCM Performance – Average Hourly Dispatch MW)}}{\textit{Winter Obligation MW}}$$

Average Hourly FCM Performance is the average hourly MW reduction amount (inclusive of any net supply) achieved during the month by the Real-Time Demand Response Resource to which the asset is mapped during dispatch or audit pursuant to Section III.13. Average Hourly Dispatch MW is the average hourly MW reduction amount (inclusive of any net supply) in the Dispatch Instructions issued during the month pursuant to Section III.13 to the Real-Time Demand Response Resource to which the asset is mapped, which would not exceed the resource's Capacity Supply Obligation. Winter Obligation MW is the committed quantity of the asset pursuant to Appendix K in MW. The Performance Factor shall not exceed 1.0. The Performance Factor for a month will apply to monthly payments in subsequent months during the term if, in those subsequent months, the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13. If the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13 in the month of December, an audit of the resource will be conducted in the month of January. The audit shall assess the resource's ability to meet its Capacity Supply Obligation plus the sum of the committed quantity pursuant to Appendix K for assets mapped to the resource. The Performance Factor calculated during this audit will be applied to the month of December.

c. **Energy Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall also receive a monthly energy payment, as follows:

Winter DR Program Energy Payment =

(MAX ($250/MWh, Zonal LMP) x MWh Delivered x 1.065) – E Payment

Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time and where the 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.

d. **Energy Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter d~~D~~uring hours in which an asset is dispatched concurrently with the hours in which it receives a demand curtailment schedule or initiates a Real-Time demand reduction pursuant to Section III.E or with the dispatch of the Real-Time Demand Response Resource to which the asset is mapped, the Energy payment received by the asset pursuant to Section III.E or Section III.13.7.2.5.3 will be subtracted from the energy payment hereunder. The energy payment for these assets will be computed as follows:

Winter DR Program Energy Payment =

MAX [(MAX ($250/MWh, Zonal LMP) x MWh Delivered) x 1.065 –

TDR Payment- E Payment, 0]

$Winter\ DR\ Program\ Energy\ Payment\ = MAX[(MAX(\$250/MWh, Zonal\ LMP)x\ MWh\ Delivered) - TDR\ Pa$

Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.4~~6~~ during the hours of dispatch excluding any performance during the thirty-minute notification time. TDR Payment is the Energy payment received by the asset pursuant to Section III.13.7.2.5.3 or Section III.E. The 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.

e. **Voluntary Performance.** If the ISO dispatches an asset more than thirty times, the asset's response to those dispatches is voluntary, and any performance by the asset in response to those dispatches would not be used to calculate the monthly payment for services under this Appendix K or to assess non-performance. However, any Energy provided by the asset in response to these dispatches would be compensated as described in the preceding paragraphs.

(g) **Non-Performance Charges.** The non-performance charges for assets providing the demand response services described in this Section III.K.4~~6~~ shall be:

i. For failure to reach 75% performance: If the asset fails to achieve an average MW performance of at least 75% of the committed MW quantity in a month, the asset shall forfeit its monthly payment for that month and for any other month during the term for which such performance is utilized for settlement.

ii. For failure to submit valid meter data: the provisions of Section III.K.4~~6~~(c)(v) shall apply with regard to meter data deemed to be zero because of quality problems.

III.K.5 Dual Fuel Commissioning Service.

As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual fuel capability.

(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.

(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the compensation for which the Market Participant is eligible if it achieves dual fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.

(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset:

(i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.

(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.1.5.2(e)(iii) and Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.

(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November 15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. ~~Generator Assets must report their usable oil inventory levels to the ISO on the first of the month during the winter and as otherwise requested by the ISO.~~ Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.

(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(e) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(e) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage ~~on May 31, 2018~~, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).

(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:

Monthly Compensation x the number of months between date of the breach and May 31, 2018

Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.

III.K.6~~7~~. Resource Auditing and Performance Monitoring.

~~Market Participants providing the service described in Section III.K.3 through III.K.5 shall~~ Participating Generator Assets must report their usable oil inventory levels and remaining contracted liquefied natural gas volumes to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.

In each winter, Market Participants providing the demand response service described in Section III.K.4~~6~~ shall be audited by the ISO in the month of January if the asset was not dispatched or audited prior to the scheduled audit. During the audit, the ISO shall dispatch the asset without prior notice and assess its performance during the sixty minutes immediately following the end of the thirty-minute notification time. The results of an audit will be treated and settled as though it were a dispatch to maintain thirty-minute Operating Reserve. Audits of assets mapped to Real-Time Demand Response Resources will be concurrent with audits of those resources. If a Real-Time Demand Response Resource with a Capacity Supply Obligation is dispatched or audited, the performance of any assets providing demand response service pursuant to this Appendix K that are mapped to that resource shall be excluded from the performance of the resource if the audit is used as a Demand Resource Commercial Operation Audit. The performance of assets dispatched or audited pursuant to this Appendix K shall be equal to the difference between the asset's adjusted Demand Response Baseline, determined pursuant to Section III.~~8~~7, and the asset's meter reading during the period of dispatch (after consideration of the thirty-minute notification time). For purposes of establishing, computing, and adjusting an asset's Demand Response Baseline, assets dispatched or audited pursuant to this Appendix K shall be treated like a dispatch or audit pursuant to Section III.13.

III.K.7~~8~~. Settlements, Cost Allocation and Financial Assurance.

(a) **Cost Allocation and Settlement~~, by Service~~**.

i. Compensation to Market Participants for ~~the oil and liquefied natural gas~~ services described in Sections III.K.2~~3~~ and III.K.3~~4~~ shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Payments shall be made to the Market

Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected.

ii. The monthly compensation described in Section III.K.~~6~~4(f)(i)-(ii) for the demand response services described in Section III.K.~~6~~ 4 shall be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the compensation is earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). The hourly compensation described in Section III.K.4~~6~~(f)(iii)-(iv) shall be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation for the hour in which the service was provided, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Payments shall be made to the Market Participants providing the services through the ISO's settlements system in the month after the ISO makes the collections referenced in the first two sentences of this paragraph.

iii. Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.

(b) **Allocation and Settlement of Non-Performance Charges.** All repayments required ~~pursuant to Sections III.K.3 and III.K.5~~herein, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only).

(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to this Appendix ~~Sections III.~~K.~~3 or III.K.5~~ shall result in a reduced refund pursuant to Section III.K.7~~8~~(b) to Real-Time Load Obligation.

APPENDIX K, ATTACHMENT 1

CONTRACT CERTIFICATION

The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:

1. Contracting parties:____
2. Date of contract:____
3. Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:____
4. Maximum total volume available under the contract:_______________________________
5. Contract term (date and years) (must span, at a minimum, December 1 through the end of February):____
6. Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]
7. Any contract terms that restrict when the supply may be taken by the Generator Asset:

   ____
8. Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]
9. Entity providing pipeline transportation: ____
10. Confirmation that contract has a "take or pay" construct: [Confirmed]

[MARKET PARTICIPANT]

By:__________________
Name:
Title:
Date:

ATTACHMENT N-1i

Clean Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective September 14, 2015

APPENDIX K

WINTER RELIABILITY SOLUTIONS

WINTER RELIABILITY SOLUTIONS

III.K.1. General.

(a) **Term.** This Appendix K is intended to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.

(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; modeled in the EMS; and either (i) dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.

(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.

(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.

(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.

(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 and III.K.3 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Notwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.

(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas. The Set Rate for the demand response service in Section III.K.4 shall be calculated as follows:

$$DR\ Set\ Rate = R_o \times [(1/H_{avg}) \times HR_g \times 100MW \times 180_h]/(100{,}000\ kW \times 3\ months)$$

Where:

R_o: Oil program Set Rate in $/bbl

H_{avg}: MW-Weighted average heat content of oil-fired units in New England = 6.0 MMBtu/bbl

HR_g: Generic heat rate = 10 MMBtu/MWh

180_h: 180 hours, which is the maximum number of hours a demand response asset could be dispatched during the winter

(h) **Conflict.** Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.

III.K.2. Oil Fuel.

Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety-fill and structural limitations. Tanks removed from service due to structural damage or for long-term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.

(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil.

(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.2(d). The December 1 inventory level will be deemed to include: oil that the ISO determines was burned to produce electricity on and after November 15 of that year, including during an audit of dual fuel capability, provided that oil used in an audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.2.

(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:

(Eligible Inventory x Set Rate) x Performance Adjustment

Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K. 2(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. Performance Adjustment shall mean:

(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)
(Total number of winter hours)

The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.

III.K.3. Liquefied Natural Gas.

Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of that winter.

(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving pipeline gas or supplies of liquefied natural gas.

(b) **Proposed Contracts.** In the notice specified in Section III.K.1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.3. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.3(c). The ISO will review the notices and inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.3(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a “first come/first served” basis and shall inform Generator Assets of their provisional acceptance by each October 15.

(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a “take-or-pay” construct; the volume specified by the Market Participant pursuant to Section III.K.3(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO's provisional acceptance will be withdrawn.

(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:

(Unused Quantity x Set Rate) x Performance Adjustment

Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. Performance Adjustment shall mean:

$$\frac{\textit{(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)}}{\textit{(Total number of winter hours)}}$$

III.K.4. Demand Response Service.

All defined terms used in this Section III.K.4 shall have the same meanings as if the asset were a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Market Participants with an asset located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including an asset with behind-the-meter generation capable of reducing demand from the electric system and delivering any net supply, are eligible to participate pursuant to this Appendix K. Assets mapped to a Real-Time Demand Response Resource are eligible to participate, subject to the additional requirements specified below, and provided that the capacity supplied by these assets is in addition to the Capacity Supply Obligation, as of December 1 of the relevant Capacity Commitment Period, of the Real-Time Demand Response Resource to which the asset is mapped, and provided further that the prohibitions in Section III.E1.1.2 are not triggered.

Except for assets mapped to a Real-Time Demand Response Resource, an asset may consist of an aggregation of individual end-use facilities so long as those facilities are located within the same Dispatch Zone, and provided further that such aggregation does not result in a quantity of demand reduction and net supply of 5 MW or greater at a single Node.

The following asset types are not eligible to provide services under this Section III.K.4: (i) Real-Time Emergency Generation Assets; (ii) any asset that is dependent upon a non-firm or an additional supply of natural gas to produce demand reductions or net supply; and (iii) any asset that participates in the energy market pursuant to Section III.1 of the Tariff.

Each Market Participant that has an asset accepted by the ISO for this service is subject to the following additional requirements from the relevant December 1 through March 1:

(a) **In service.** By December 1, participating assets must, in accordance with the existing requirements for Real-Time Demand Response Assets and Real-Time Emergency Generation Assets: (i) be registered with the ISO; (ii) have meters installed and operational; (iii) have a valid Demand Response Baseline; (iv) have a Demand Designated Entity to which Dispatch Instructions are communicated; and (v) otherwise be fully ready to respond.

(b) **Size of Program and Assets.** Each participating asset shall provide at least 100 kW of capability. No more than 100 assets at a level not to exceed 100 MW shall be accepted by the ISO pursuant to this Appendix K.

(c) **Metering.**

i. Market Participants must meet the metering requirements specified in Appendix III.E and the ISO New England manuals, with the exception that 5-minute meter data does not have to be reported to the ISO in real time for assets not mapped to a Real-Time Demand Response Resource.

ii. To the extent that an asset consists of an aggregation of individual end-use facilities, Market Participants must submit a single set of interval meter data, as measured from each facility's Retail Delivery Point, representing the sum of the metered demand of the end-use facilities comprising the asset.

iii. Market Participants shall report meter data and may submit meter data corrections to the ISO using the Demand Response Market User Interface within 2.5 business days after the Operating Day.

iv. Meter data corrections may be submitted during the 70-day period beginning with the first of the month following the operating month. To the extent meter data affecting an asset's performance measurement and passing all quality checks has not been submitted by the initial settlement deadline (i.e., within 2.5 business days after the Operating Day), payments related to that asset shall be deferred to the resettlement process.

v. In the event that valid meter data affecting an asset's monthly performance measurement that passes all quality checks is not submitted by the end of the 70-day data correction limit, that asset's performance shall be deemed to be zero for the intervals for which the meter data did not pass all quality checks.

(d) **Dispatch.**

i. Assets must be available for dispatch in real time between hours ending 0600 and 2300 on all days.

ii. Each dispatch shall be for no more than six hours.

iii. There will be no more than two dispatches per asset per day.

iv. There shall be at least four hours between the end of one dispatch and the start time of another dispatch.

v. Assets will be dispatched by the ISO at its discretion prior to, or concurrent with, ISO New England Operating Procedure No. 4, Action 2. The ISO may aggregate assets into blocks and dispatch only those assets comprising the blocks.

vi. Each asset shall be required to respond to Dispatch Instructions no more than thirty times.

vii. The ISO will communicate Dispatch Instructions to the Demand Designated Entity specified by the Market Participant for each participating asset.

viii. Assets will be dispatched for their entire, committed MW quantity except in cases where such dispatch may cause or worsen a local reliability problem. The ISO may, upon notification to the Demand Designated Entity, exclude from dispatch assets located in a particular Dispatch Zone, and/or individual assets where the committed MW quantity is 5 MW or more.

ix. Except as outlined in viii. above, assets must produce the MW quantity accepted pursuant to this Appendix K within thirty minutes of the issuance of a Dispatch Instruction.

x. If assets mapped to a Real-Time Demand Response Resource are dispatched pursuant to this Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource, and the amount of demand reduction plus any net supply produced in that interval is less than the Real-Time Demand Response Resource's Capacity Supply Obligation plus the sum of the asset's committed MW quantity pursuant to Appendix K, the amount of demand reduction plus any net supply produced shall be credited first to the Real-Time Demand Response Resource's Capacity Supply Obligation and the remainder shall be credited pro-rata to each asset with an obligation pursuant to Appendix K based on asset performance.

(e) **Acceptance Criteria.** Market Participants must indicate their commitment to provide this demand response service by providing the notice indicated in Section III.K.1(e). That notice must include: the name and other pertinent identifiers of the asset that the Market Participant is seeking to enroll, the asset's electrical location, the MW quantity of demand reduction and any net supply, as measured from the asset's Retail Delivery Point, that the asset is willing and able to produce in response to Dispatch Instructions, and the method(s) by which the demand reduction or any net supply would be produced. If the Market Participant has not yet identified all of the assets that will be recruited to meet the service requirements, the Market Participant shall provide a description of how it will meet the requirements, and provide the Dispatch Zone within which these assets will be located. If an asset specified in the notice consists of an aggregation of individual end-use facilities, the information shall be provided for each facility that is part of the aggregation. The ISO shall accept up to 100 qualified assets at a level not to exceed 100 MW from those Market Participants providing notice, based on:

i. The asset's proposed capacity;

ii. The asset's location relative to known constrained areas; and/or

iii. Any historic performance from the asset.

The ISO may accept or reject any and all assets proposed for participation.

(f) Compensation.

a. **Monthly Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall be compensated under this Appendix K through a monthly payment of the Set Rate multiplied by the average MW performance achieved by the asset in the month, provided that such MW performance shall not exceed 150% of the committed MW quantity. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If the asset was not dispatched or audited in the month of December, the payment for that asset for that month will be based on its average MW performance in response to dispatch (including a dispatch for an audit) in the following month. If an asset was not dispatched in January or February, but was dispatched or audited in a previous month, the asset's payment for the month in which it was not dispatched will be based on its average MW performance in the most recent month in which the asset was dispatched or audited.

b. **Monthly Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter, the monthly payment for assets that are mapped to a Real-Time Demand Response Resource will be the Set Rate multiplied by the average MW performance achieved by the asset in the month not to exceed 100% of the committed MW quantity, and further multiplied by the Performance Factor. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If an asset is dispatched in a month pursuant to Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource to which it is mapped, a Performance Factor will be calculated as follows:

$$\textit{Performance Factor} = \frac{\textit{(Average Hourly FCM Performance – Average Hourly Dispatch MW)}}{\textit{Winter Obligation MW}}$$

Average Hourly FCM Performance is the average hourly MW reduction amount (inclusive of any net supply) achieved during the month by the Real-Time Demand Response Resource to which the asset is mapped during dispatch or audit pursuant to Section III.13. Average Hourly Dispatch MW is the average hourly MW reduction amount (inclusive of any net supply) in the Dispatch Instructions issued during the month pursuant to Section III.13 to the Real-Time Demand Response Resource to which the asset is mapped, which would not exceed the resource's Capacity Supply Obligation. Winter Obligation MW is the committed quantity of the asset pursuant to Appendix K in MW. The Performance Factor shall not exceed 1.0. The Performance Factor for a month will apply to monthly payments in subsequent months during the term if, in those subsequent months, the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13. If the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13 in the month of December, an audit of the resource will be conducted in the month of January. The audit shall assess the resource's ability to meet its Capacity Supply Obligation plus the sum of the committed quantity pursuant to Appendix K for assets mapped to the resource. The Performance Factor calculated during this audit will be applied to the month of December.

c. **Energy Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall also receive a monthly energy payment, as follows:

Winter DR Program Energy Payment =

(MAX ($250/MWh, Zonal LMP) x MWh Delivered x 1.065) – E Payment

Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time and where the 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.

d. **Energy Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter during hours in which an asset is dispatched concurrently with the hours in which it receives a demand curtailment schedule or initiates a Real-Time demand reduction pursuant to Section III.E or with the dispatch of the Real-Time Demand Response Resource to which the asset is mapped, the Energy payment received by the asset pursuant to Section III.E or Section III.13.7.2.5.3 will be subtracted from the energy payment hereunder. The energy payment for these assets will be computed as follows:

Winter DR Program Energy Payment =

MAX [(MAX ($250/MWh, Zonal LMP) x MWh Delivered) x 1.065 –

TDR Payment- E Payment, 0]

Winter DR Program Energy Payment = MAX[(MAX($250/MWh, Zonal LMP)x MWh Delivered) – TDR Pa

Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this

Section III.K.4 during the hours of dispatch excluding any performance during the thirty-minute notification time. TDR Payment is the Energy payment received by the asset pursuant to Section III.13.7.2.5.3 or Section III.E. The 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.

e. **Voluntary Performance.** If the ISO dispatches an asset more than thirty times, the asset's response to those dispatches is voluntary, and any performance by the asset in response to those dispatches would not be used to calculate the monthly payment for services under this Appendix K or to assess non-performance. However, any Energy provided by the asset in response to these dispatches would be compensated as described in the preceding paragraphs.

(g) **Non-Performance Charges.** The non-performance charges for assets providing the demand response services described in this Section III.K.4 shall be:

i. For failure to reach 75% performance: If the asset fails to achieve an average MW performance of at least 75% of the committed MW quantity in a month, the asset shall forfeit its monthly payment for that month and for any other month during the term for which such performance is utilized for settlement.

ii. For failure to submit valid meter data: the provisions of Section III.K.4(c)(v) shall apply with regard to meter data deemed to be zero because of quality problems.

III.K.5 Dual Fuel Commissioning Service.

As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual fuel capability.

(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.

(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the compensation for which the Market Participant is eligible if it achieves dual fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.

(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset: (i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.

(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.1.5.2(e)(iii) and Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.

(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November 15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.

(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(e) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(e) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).

(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:

Monthly Compensation x the number of months between date of the breach and May 31, 2018

Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.

III.K.6. Resource Auditing and Performance Monitoring.

Participating Generator Assets must report their usable oil inventory levels and remaining contracted liquefied natural gas volumes to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.

In each winter, Market Participants providing the demand response service described in Section III.K.4 shall be audited by the ISO in the month of January if the asset was not dispatched or audited prior to the scheduled audit. During the audit, the ISO shall dispatch the asset without prior notice and assess its performance during the sixty minutes immediately following the end of the thirty-minute notification time. The results of an audit will be treated and settled as though it were a dispatch to maintain thirty-minute Operating Reserve. Audits of assets mapped to Real-Time Demand Response Resources will be concurrent with audits of those resources. If a Real-Time Demand Response Resource with a Capacity Supply Obligation is dispatched or audited, the performance of any assets providing demand response service pursuant to this Appendix K that are mapped to that resource shall be excluded from the performance of the resource if the audit is used as a Demand Resource Commercial Operation Audit. The performance of assets dispatched or audited pursuant to this Appendix K shall be equal to the difference between the asset's adjusted Demand Response Baseline, determined pursuant to Section III.7, and the asset's meter reading during the period of dispatch (after consideration of the thirty-minute notification time). For purposes of establishing, computing, and adjusting an asset's Demand Response Baseline, assets dispatched or audited pursuant to this Appendix K shall be treated like a dispatch or audit pursuant to Section III.13.

III.K.7. Settlements, Cost Allocation and Financial Assurance.

(a) **Cost Allocation and Settlement**.

i. Compensation to Market Participants for services described in Sections III.K.2 and III.K.3 shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). Payments shall be made to the Market Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected.

ii. The monthly compensation described in Section III.K.4(f)(i)-(ii) for the demand response services described in Section III.K.4 shall be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the compensation is earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). The hourly compensation described in Section III.K.4(f)(iii)-(iv) shall be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation for the hour in which the service was provided, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only). All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Payments shall be made to the Market Participants providing the services through the ISO's settlements system in the month after the ISO makes the collections referenced in the first two sentences of this paragraph.

iii. Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.

(b) **Allocation and Settlement of Non-Performance Charges.** All repayments required herein, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding Real-Time Load Obligation associated with Dispatchable Asset Related

Demand Resources (pumps only). Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only).

(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to this Appendix K. shall result in a reduced refund pursuant to Section III.K.7(b) to Real-Time Load Obligation.

APPENDIX K, ATTACHMENT 1

CONTRACT CERTIFICATION

The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:

1. Contracting parties:____
2. Date of contract:____
3. Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:____
4. Maximum total volume available under the contract:_________________________________
5. Contract term (date and years) (must span, at a minimum, December 1 through the end of February):____
6. Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]
7. Any contract terms that restrict when the supply may be taken by the Generator Asset:

   ____
8. Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]
9. Entity providing pipeline transportation: ____
10. Confirmation that contract has a “take or pay” construct: [Confirmed]

[MARKET PARTICIPANT]

By:__________________
Name:
Title:
Date: