ISO new england

January 13, 2017

BY ELECTRONIC FILING

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

RE: **<u>ISO New England Inc.; Filing of CONE and ORTP Updates</u>**
<u>Docket No. ER17- -000</u>

Dear Secretary Bose:

ISO New England Inc. (the "ISO) hereby electronically submits this transmittal letter and revisions to the ISO's Tariff[1] to update the Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values used in the Forward Capacity Market (the package of tariff changes is referred to hereafter as the "CONE and ORTP Updates"). The ISO is requesting that the new values become effective on March 15, 2017, coinciding with the beginning of the approximately year-long auction-administration cycle for the twelfth Forward Capacity Auction ("FCA 12"), which is for the 2021-2022 Capacity Commitment Period and will be administered by the ISO in February 2018.

I. EXECUTIVE SUMMARY

The Tariff requires that the CONE, Net CONE and ORTP values used in the Forward Capacity Market be reevaluated and updated at least once every three years. At a high level, the CONE and Net CONE values are, respectively, estimates of the total and net costs of developing the most economically efficient type of new capacity resource in New England. The ORTP values are estimates of the entry costs for all resource types that may participate in the Forward Capacity Market and are used to screen for new resource offers that may require further review as part of the buyer-side market power mitigation structure.

The ISO retained the energy consultancy firm Concentric Energy Advisors ("Concentric") to assist in the preparation of the updated CONE, Net CONE and ORTP values. Concentric partnered with the engineering firm, Mott MacDonald, for purposes of developing the detailed, bottoms-up estimates of entry costs for each of the resource types that were evaluated.

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[1] Capitalized terms used but not defined in this filing 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.

Concentric and Mott MacDonald prepared a draft report detailing the methodology they used to estimate entry costs and that report was reviewed by the ISO and stakeholders over a six month period. Based on feedback from the ISO and stakeholders, the entry cost calculations detailed in the report were refined and revised throughout the review process. The final version of the report, the "ISO-NE CONE and ORTP Analysis" or "CEA Report," is included as Attachment 1 of this filing and establishes the substantive basis for the updated CONE, Net CONE and ORTP values.

As discussed in Section VI of this filing letter, the stakeholder review process did not result in NEPOOL support for the CONE and ORTP Updates. During the review process, some stakeholders differed over the selection of the reference technology used for purposes of determining the CONE and Net CONE values.[2] Concentric and Mott MacDonald recommended, and the ISO selected, a gas-fired simple cycle combustion-turbine ("CT") as the reference technology for the updated values. Some stakeholders supported the selection of a gas-fired combined-cycle resource ("CC") as the reference technology. However, an amendment that was offered during the stakeholder review process that would have selected a CC as the reference technology was not supported by NEPOOL. The reasons for selecting a CT resource as the reference technology are fully discussed in Section IV.F of this filing letter. In addition, some stakeholders did not support the capacity factor calculation and the resulting ORTP value for onshore wind resources. These stakeholders proposed the use of a higher capacity factor assumption that would produce a significantly lower ORTP for onshore wind resources. The ISO and its Internal Market Monitor ("IMM") do not support the use of a higher capacity factor assumption as they believe that the methodology and assumptions used to calculate the updated ORTP for onshore wind resources, as discussed in Section 4.F of the CEA Report, are reasonable and consistent with the objectives of the buyer-side market power mitigation structure.

II. REQUESTED EFFECTIVE DATE

The ISO requests that the CONE and ORTP Updates become effective on March 15, 2017. The implementation of the CONE and ORTP Updates on the requested effective date means that the new values will be in place during the initial stages of the FCA 12 qualification process. The use of the CONE, Net CONE and ORTP values in the Forward Capacity Market is discussed in more detail in Section IV.A of this filing letter.

III. 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 has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability

[2] The process of screening reference technologies is discussed in Section IV.C of this filing letter.

standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

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IV. EXPLANATION OF THE CONE AND ORTP UPDATES

A. The use of CONE, Net CONE and ORTP values in the Forward Capacity Market

As part of the design of the Forward Capacity Market, the ISO estimates the cost of developing new resources that may enter the market. These estimated entry costs are then used for a variety of purposes. One of the entry cost estimates is the total cost of developing a new resource, without any adjustment for the revenues that the resource might earn. This total cost (or "gross" cost) of new entry is referred to in the market rules as "CONE."[3] Another estimated entry cost is "Net CONE,"[4] which is the gross cost of new entry less the variable profit the resource is expected to earn from energy, ancillary service and other market services. As discussed in Section IV.F, the CONE and Net CONE values are estimated for the resource type that is expected to be the most cost-effective technology for new entry over the long term. Finally, estimates of the entry costs for all resource types that are likely to participate in the Forward Capacity Market are calculated to establish the Offer Review Trigger Prices, which are technology-specific thresholds used to screen for new resource offers that require further review as part of the buyer-side market power mitigation structure.

The remainder of this section of the filing letter provides additional detail concerning how and when the CONE, Net CONE and ORTP values are used during the annual capacity market auction process. The primary use of Net CONE is as a parameter that helps to define

[3] The market rules define CONE as follows: "Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4." *See* Tariff, Section I.2.2 (Definitions).

[4] The market rules define Net CONE as follows: "Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years." *See* Tariff, Section I.2.2 (Definitions).

how demand is represented in the annual auction process. Demand is represented by system and zonal demand curves that are calculated to reflect the Marginal Reliability Impact (or "MRI") of adding capacity in different locations.[5] The market rules specify that the system demand curve must be scaled so that the capacity quantity associated with the Net CONE value satisfies the New England region's resource adequacy reliability standard (which is a Loss of Load Expectation of 0.1 days per year).[6]

The CONE and Net CONE values also are used to set the Forward Capacity Auction Starting Price. The market rules specify that the Forward Capacity Auction Starting Price is the higher of: (1) CONE, and; (2) 1.6 multiplied by Net CONE.[7] As the Commission has recognized, the practical effect of the Forward Capacity Auction Starting Price is to establish a price cap in the capacity market.[8]

While the CONE and Net CONE values are integral parts of the Forward Capacity Auction itself, the values also are used during the qualification process that precedes each auction. The CONE and Net CONE values are first used in an auction cycle when capacity suppliers with existing resources submit any retirement de-list bids. The market rules specify that the remaining economic life of any resources subject to a retirement de-list bid will be calculated by the IMM pursuant to a formula that includes the Forward Capacity Auction Starting Price (which, as noted above, is a function of the CONE and Net CONE values).[9] In submitting their retirement de-list bids, capacity suppliers must choose whether to use the same economic life assumption that the IMM will use, or to use an alternative that they may justify with supplemental information. Importantly, for FCA 12, retirement de-list bids must be submitted to the IMM between March 10 and March 24, 2017.[10]

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[5] The current demand curve design for the Forward Capacity Market was accepted by the Commission in an order issued on June 28, 2016 in Docket No. ER16-1434. *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Filing*, 155 FERC ¶ 61,319 (2016).

[6] *See* Market Rule 1, Section III.13.2.2.4 (Capacity Demand Curve Scaling Factor).

[7] *See* Market Rule 1, Section III.13.2.4 (Forward Capacity Auction Starting Price and the Cost of New Entry).

[8] The current rules concerning the Forward Capacity Auction Starting Price were accepted by the Commission in an order issued on May 30, 2014 in Docket No. ER14-1639. *See ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions,* 147 FERC ¶ 61,173 (2014).

[9] *See* Market Rule 1, Section III.13.1.2.3.2.1.2.B (Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows), which states that the IMM will calculate a resource's remaining economic life in accordance with Section III.13.1.2.3.2.1.2.C.

[10] The price of the submitted retirement de-list bid (not the price determined by the IMM or the price determined by the Commission) is used if the capacity supplier elects "conditional treatment" pursuant to Market Rule 1, Section III.13.2.5.2.1(c). The conditional treatment option allows a capacity supplier to elect to only take on a Capacity Supply Obligation if the auction-clearing price exceeds the price of its submitted retirement de-list bid.

The CONE, Net CONE and the ORTP values continue to be used throughout the qualification process for FCA 12. Project Sponsors with new capacity resources likely will consider the updated values, and their impact on the system and zonal demand curves, as they prepare for the submission of New Capacity Show of Interest Forms.[11] For FCA 12, the window for submitting these show-of-interest forms is April 14, 2017 to April 28, 2017.

Following the submission of retirement de-list bids and show-of-interest forms, the ISO and the IMM will begin the process of reviewing the various submissions, applying the CONE, Net CONE and ORTP values as applicable. No later than June 22, 2017, the IMM will release Retirement Determination Notifications for retirement de-list bids,[12] which will incorporate assumptions regarding the CONE/Net CONE values.

The updated CONE, Net CONE and ORTP values continue to be relevant for other auction administration purposes up to and including the FCA 12 auction in February 2018. For example, the Forward Capacity Auction Starting Price (based on the CONE/Net CONE value) is used to determine the financial assurance requirement for non-commercial capacity.[13]

B. The Rules for Setting and Updating the CONE, Net CONE and ORTP Values

The CONE, Net CONE and ORTP values are filed with, and approved by, the Commission and are specifically enumerated in the Tariff. The currently applicable CONE and Net CONE values are set out in Market Rule 1, Section III.13.2.4. The current values were initially filed and accepted by the Commission in 2014 in Docket No. ER14-1639 as part of the implementation of a sloped system demand curve in New England's capacity market.[14] The currently applicable ORTP values are set out in Market Rule 1, Appendix A, Section III.A.21.1.1. The ORTP values were last updated, filed and accepted by the Commission in 2014 in Docket No. ER14-1477-000.[15]

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[11] *See* Market Rule 1, Section III.13.1.1.2.1.

[12] As used in this filing letter, "retirement de-list bids" refers to both Retirement De-List Bids and Permanent De-List Bids.

[13] Tariff, Section I, Exhibit IA, ISO New England Financial Assurance Policy, Section VII(B)(2)(b).

[14] *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, 147 FERC ¶ 61,173 (2014) (the "2014 CONE Order").

[15] The minimum offer price review structure and ORTP values were filed with and accepted by the Commission in a series of orders issued in 2013 and 2014. The primary orders were: *ISO New England Inc.*, *Order on Compliance Filing*, 142 FERC ¶ 61,107 (2013) issued February 12, 2013 in Docket No ER12-953 (the "February 12, 2013 Order"); *ISO New England, Inc.*, *Order on Proposed Tariff Revisions*, 146 FERC ¶ 61,084 (2014) issued February 11, 2014 in Docket No. ER14-616 (the "February 11, 2014 Order"), and; *ISO New England Inc.*, *Order on Proposed Tariff Revisions*, 147 FERC ¶ 61,109 (2014) issued on May 12, 2014 in Docket No. ER14-1477 (the "May 12, 2014 Order").

The market rules require that the CONE, Net CONE and ORTP values be recalculated at least once every three years using updated data.[16] In between full recalculations, the CONE, Net CONE and ORTP values are updated annually using indices that are specified in the market rules.[17] The instant filing represents the results of the latest three-year full recalculation of the CONE, Net CONE and ORTP values using updated data concerning the estimated construction costs and expected net revenues of new resources likely to participate in the market. The updated values will be used beginning with FCA 12.

C. Resource Screening and Assumptions

As discussed in Section 3.A of the CEA Report, the first step in updating the CONE, Net CONE and ORTP values is to develop and apply screening criteria to identify the resource types that should be subject to a detailed cost and expected revenue evaluation.

For the CONE/Net CONE values, the following screening criteria were used to evaluate resource types that could be used to set the CONE/Net CONE values for FCA 12:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions;

2. Must have reliable cost information available to calculate a CONE value using a full "bottom up" analytical approach.

These same screening criteria were used when the initial CONE and Net CONE values were set in 2014 in Docket No. ER14-1639. In its order accepting those values, the Commission agreed that the CONE/Net CONE values should reflect a resource type that is likely to be developed in New England and for which cost and revenue estimates can be developed with confidence.[18]

As discussed in further detail in Section 3.G of the CEA Report, applying these screening criteria led to the selection of four candidate reference technologies to be more fully evaluated for purposes of updating the CONE/Net CONE values. The four candidate reference technologies that were selected were: (1) the 7HA.02 Simple Cycle Gas Turbine (the "CT"); (2) the 7HA.02 Combined Cycle Gas Turbine (the "CC"); (3) the M6000PF+ Aeroderivative Gas Turbine (the "Aero"), and; (4) the LMS100PA Advanced Aeroderivative (the "Advanced Aero"). Each of the four candidate reference technologies were then subject to full-scale cost estimation as detailed in the CEA Report.

For the ORTP values, entry costs are estimated for <u>all</u> new resource technologies that may participate in the Forward Capacity Market and for which there is reliable cost

[16] *See* Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a).

[17] *See* Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(e).

[18] Initial CONE Order at P 32.

information.[19] There are some resource types that may participate in the Forward Capacity Market but for which there is not reliable cost information. In these cases, the ORTP is set to the Forward Capacity Auction Starting Price.[20]

D. Estimating the Gross Costs of New Entry or "CONE"

Updating the CONE and Net CONE values begins with estimating the gross costs of financing and constructing, in New England, each of the four candidate resource types.[21] As discussed in Section 3.B of the CEA Report, before the costs of the candidate resource types were estimated, certain assumptions were developed concerning the location, plant configuration, interconnections to the gas and electric distribution systems, dual fuel capability, and environmental control capabilities of the resources. In brief, it was assumed that the candidate resources types would share the following characteristics: (1) location in an area of the New England power system with existing gas/electric interconnection infrastructure and where resource retirements are likely (Bristol County, Massachusetts); (2) development at a previously undeveloped, or "greenfield" site (primarily because the costs of re-development at existing, or "brownfield," power plant sites can be highly variable and site-specific, and therefore not a reliable predictor of future entry costs); (3) able to operate on natural gas or distillate fuel oil, with the latter as a backup fuel source (also known as "dual fuel" capability); (4) operate with various standard, commercially available environmental controls, including carbon monoxide and nitrogen oxide reduction (also called Selective Catalytic Reduction) equipment; (5) cooling system designs that appropriately balance efficiency and permitting considerations, and; (6) land leasing, property tax and insurance structures commonly used by project developers.

Sections 3.C and 3.D of the CEA Report detail how Concentric and Mott MacDonald prepared the capital and fixed operating and maintenance cost estimates for the four candidate reference technologies, based on modern construction techniques and materials for electricity generating stations and related facilities. Using its database of actual cost estimates for several hundred power projects, Mott MacDonald was primarily responsible for developing the major equipment costs, field construction labor hours, and materials quantities for cost estimation purposes. The financial assumptions used by Concentric and Mott MacDonald for cost estimation purposes, including inflation, depreciation, tax treatment, cost of capital (for both debt and equity), and capital structure, are detailed in Section 3.E of the CEA report.

The CONE and Net CONE values for the four candidate reference technologies are set out in Table 35 in Section 3.G of the CEA Report. They are as follows:

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[19] Market Rule 1, Appendix A, Section III.A.21.1.

[20] Market Rule 1, Appendix A, Section III.A.21.1.1 (Other Resources).

[21] The ORTP values, which cover all of the resource types that might participate in the capacity market, are developed using a cost estimation process that is broadly similar to the cost estimation process used for the CONE and Net CONE values. However, the ORTP values serve a different purpose than the CONE and Net CONE values and the cost estimation process for each is not identical. Section IV.G of this filing letter discusses the development of the ORTP values.

Candidate Reference Technology	CONE ($/kW-month)
CC	15.62
CT	11.35
Aero	25.98
Advanced Aero	21.03

E. Estimating the Net Costs of New Entry or "Net CONE"

The Net CONE values for the four candidate reference technologies are calculated by subtracting the non-capacity market net revenues that each type of resource can be expected to earn from that resource's CONE value. The methodology used to calculate the net revenue offsets for each type of resource is explained in Section 3.F of the CEA Report. Broadly speaking, there are three types of offsets: energy market net revenue, ancillary services revenues, and "Pay for Performance" (or "PFP") revenue.

As discussed in Section 3.F.1 of the CEA Report, the energy market net revenue offset was determined in two steps. First, a twenty-year forecast of hourly, zonal energy prices was developed using a standard, commercially-available, hourly energy market dispatch simulation model known as AURORAxmp. This simulation model incorporates a variety of standard assumptions; including forecasts of natural gas prices and emissions allowance prices, a load forecast, and other factors that may affect future wholesale electricity prices in New England. Second, using the forecast hourly energy prices from the AURORAxmp simulation, a simplified resource-specific dispatch algorithm was used to estimate each candidate reference technology's operating hours each year, along with the resource's projected energy market revenue, fuel costs, emissions costs, and variable operating costs. Each resource's projected energy market revenue net of (that is, after subtracting the cost of) the aforementioned operating costs comprises its estimated net energy revenue. The estimated hourly net energy revenue was totaled for each year of the facility's projected twenty-year life.

Next, as further discussed in Section 3.F.1 of the CEA Report, an ancillary services revenue offset was calculated for each candidate reference technology. The ancillary services revenue offset was calculated by developing payment rates for two ancillary services markets in New England, the locational forward reserve market and the real-time reserve market, for both the ten-minute non-spinning reserve ("TMSNR") and thirty-minute operating reserve ("TMOR") products. The payment rates were developed based on several years of recent market data for each service and product in the New England markets. Importantly, in calculating the appropriate ancillary services revenue offsets, the operating characteristics of each candidate reference technology were used to assess which ancillary services it could be expected to supply. For example, the specific ten-minute energy ramp capability (from a cold-start) and thirty-minute energy ramp capabilities of the CT reference technology (the GE Frame 7HA.02) were used to determine the amount of TMNSR and TMOR it could be expected to provide in both the forward and real-time reserve markets, and the associated projected annual revenues for each product in each market. As discussed in Section 3.F.1 of the CEA report, slightly different ancillary service calculation methods were employed for the other technologies consistent with their operating characteristics. Finally, the estimated ancillary services revenue for each product was totaled for each year of the facility's projected twenty-year life

Finally, the sum of the energy and ancillary services revenues was entered into the larger financial cash-flow model employed to estimate Net CONE for each candidate reference technology.

As discussed in Section 3.F.2 of the CEA Report, each of the candidate reference technologies also is expected to earn additional PFP revenue under New England's two-settlement capacity market design. Expected PFP revenue was calculated based on the ISO's system-level studies of the expected number of Capacity Scarcity Conditions annually. These are determined using the ISO's reliability planning simulation model.[22] CEA then estimated the expected performance of each candidate reference technology, applied the specific performance payment rules and rates for PFP,[23] and thereby determined each resource's expected annual Capacity Performance Payments. As with the energy and ancillary services revenue offsets, the estimated annual Capacity Performance Payments (*i.e.*, expected PFP revenue) for each year of the facility's projected twenty-year life was then entered into the larger financial cash-flow model employed to estimate Net CONE for each candidate reference technology.

The Net CONE values of the four candidate reference technologies, as set out in Table 35 in Section 3.G of the CEA Report, are as follows:

Candidate Reference Technology	**Net CONE ($/kW-month)**
CC	10.00
CT	8.04
Aero	22.35
Advanced Aero	17.36

F. Selecting the Final CONE and Net CONE Values

The final step in updating the CONE and Net CONE values is to select from the four candidates the single reference technology to be used to set the CONE/Net CONE values. As noted earlier in Section IV.C of this filing letter, the candidate reference technologies were selected because it is likely that they could be economic for merchant entry under long-term equilibrium conditions and there is reliable cost information available to estimate entry costs for each technology. From a market design perspective, the final CONE and Net CONE values generally should be based on the technology that is expected to be the most economically efficient and that is commercially available to new capacity suppliers.[24] Setting the CONE and

[22] The most recent study of expected short hour events can be found at: https://www.iso-ne.com/static-assets/documents/2016/10/PSPC10132016_A2_2020-21_Reserve_Deficiencies_Hours_Final.pdf.

[23] The rules for calculating Capacity Performance Payments are set out in the PFP-related market rules that will become effective on June 1, 2018 (Market Rule 1, Section III.13.7.2.).

[24] Initial CONE Order at P 32.

Net CONE values in accordance with this design principle ensures that the demand curves used in the auction are consistent with the region's reliability planning objectives and will procure capacity cost-effectively in the Forward Capacity Market.[25]

Based on the results of the cost estimates for the four commercially-available candidate reference technologies, as discussed in Section 3.G of the CEA Report, the most economically efficient resource type is the CT with a Net CONE value of $8.04/kW-month. The next most efficient resource type is the CC, but its Net CONE value is over 24% higher at $10.00/kW-month. Accordingly, the CEA Report recommends, and the ISO proposes, to use the CT value to set the new, updated CONE and Net CONE values.[26] From a market design perspective, the selection of the CT reference technology to establish the updated CONE and Net CONE values is straightforward. As noted earlier, in order for the demand curves that are used in the auction to function efficiently, the CONE and Net CONE values generally should be based on the most efficient resource type that is commercially available. The CT satisfies this condition.

The selection of the CT reference technology for the updated CONE/Net CONE values reflects a change from the selection of a CC reference technology during the last CONE/Net CONE updates in 2014. The CT reference technology could have been an appropriate choice in 2014 based solely on estimated costs. However, the CC reference technology was selected, in large part, based on the observation that as of that time, no new CT facilities had cleared the Forward Capacity Market.[27] There was also some concern that environmental considerations could make it difficult for a CT resource to be permitted in New England.[28] Finally, there were concerns in 2014 that the then-existing capacity market design, including the then-present administrative pricing rules, could result in under-procurement of capacity if the CONE/Net CONE values were set too low. Considering all of these factors, the ISO proposed and the Commission accepted setting the 2014 CONE/Net CONE values based on a CC reference technology.

The considerations that led to the selection of the CC reference technology in 2014 are no longer applicable to the Forward Capacity Market. As noted in the CEA Report, CT resources

[25] This principle, as applied to the new sloped system and zonal demand curves accepted by the Commission earlier this year in Docket No. ER16-1434, was discussed at pp. 46-47 of the Geissler/White Testimony submitted by the ISO in that proceeding.

[26] It is notable that the proposed Net CONE value of $8.04/kW-month is significantly less than the $11.08/kW-month value that was established in 2014. The difference is primarily explained by the switch to use a CT instead of a CC as the reference technology. In addition, and as discussed further below, there have been improvements to the ancillary service markets since the last CONE/Net CONE updates and these market improvements tend to disproportionately benefit more flexible technologies such as the CT, relative to the CC.

[27] *See* pp. 63-65 of the Newell/Ungate Testimony submitted by the ISO in Docket No. ER14-1639. The testimony noted that as of 2014 there had been no merchant development of CT resources in regions with capacity markets since 2009. *Id*. at pp. 16-18.

[28] Newell/Ungate Testimony at pp. 16-18.

have participated in and cleared recent Forward Capacity Auctions.[29] In addition, the concern that deficiencies in the capacity market rules could result in systemic under-procurement have been addressed with the implementation of the MRI-based system and zonal demand curves, and with the concurrent elimination of the administrative pricing rules.[30] More specifically, the design principles used to establish the new MRI-based demand curves accurately reflect the incremental reliability value of capacity whereas the previous linear demand curve design did not. Under the new design, the demand curves have a convex shape because capacity's reliability value increases dramatically in a short system as capacity becomes tighter, and capacity's reliability value only decreases gradually when the system is long. The convex shape works to ensure that the system is highly likely to meet its reliability objective even in cases in which capacity market clearing prices are not equal to Net CONE every year.[31] With the new convex, MRI-based demand curves in place, it is appropriate that the updated CONE/Net CONE values be based on the most economically efficient, commercially available technology, which is the CT reference technology.

Not only are some of the factors that led to the selection of a CC reference technology in 2014 no longer present, but there also have been significant changes to the market design that favor the selection of the CT reference technology at this time.[32] Specifically, in the past several years there have been several important capacity, energy, and reserve market changes that are likely to favor the development of more flexible resources such as those represented by the CT reference technology. One notable change is the implementation, beginning with the Capacity Commitment Period that begins on June 1, 2018, of the two-settlement capacity market design (*i.e.*, Pay for Performance) that links capacity revenues to resource performance during reserve deficiencies. In addition, at the Commission's direction, reserve constraint penalty factors were increased substantially at the end of 2014, which produces higher reserve market prices during scarcity conditions. In addition, in 2012 and in 2013, the ISO increased overall reserve requirements (in the real-time and forward reserve markets, respectively) to account for historical reserve non-performance rates; these changes increase overall reserve revenues and

[29] CEA Report at Table 1.

[30] These changes are effective beginning with FCA 11. *See ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Filing*, 155 FERC ¶ 61,319 (2016). The interactions between the MRI-based demand curves and Net CONE were discussed extensively in the answer that the ISO submitted in the zonal demand curve proceeding in mid-2016. *See* Section B of Motion for Leave to Answer and Answer of ISO New England Inc. at pp. 7-14, Docket No. ER16-1434, submitted May 27, 2016.

[31] Section VIII of the Geissler/White Testimony submitted by the ISO in Docket No. ER16-1434 explains that the MRI-based demand curves used in the capacity market are expected to perform well under a range of conditions, including instances in which clearing prices deviate from Net CONE.

[32] In the 2014 CONE Order at P 34, the Commission recognized that periodic reevaluation of the reference technology is important "since market activity and technology change over time."

primarily benefit flexible, fast-start resources, such as the CT.[33] Finally, in early 2017 new energy market rules will take effect that improve real-time price formation when fast-start resources are deployed. Taken together, these market changes make CT resources considerably more attractive financially to potential project developers now than at the time of the 2014 Net CONE study, as the recent entry and clearing of CT technologies in the Forward Capacity Market attests. Accordingly, these changes further support the selection of the CT reference technology for the CONE/Net CONE values going forward.

While not determinative, it is important to note that the proposed use in New England of the CT reference technology to set CONE/Net CONE values is consistent with the way that those values are set in other nearby regions with organized capacity markets. For example, PJM's tariff specifies that the "Reference Resource" used for entry cost purposes is a combustion turbine.[34] The PJM entry cost values were last subject to a full cost evaluation and reset in 2014 in Docket No. ER14-2940 and are subject to quadrennial review.[35]

In New York, the reference technology is specified by NYISO's tariff as a peaking plant "with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."[36] In its recent Commission filing reflecting the results of its latest review of new entry costs, NYISO proposed to continue to use an F-class CT as the reference technology in New York's capacity market.[37] The use of the newer H-class CT as the reference technology in New England is consistent with the more forward-looking nature of New England's capacity market, compared to the New York market, and the fact that project developers are using the H-class CT technology for resources that would enter service in New England in 2021 and later. Notably, NYISO, using different financial and engineering consultants than the ISO, also independently evaluated the net entry costs of an H-class CT and reached nearly identical results as Concentric and Mott MacDonald.[38]

[33] These reserve market changes were not fully accounted for when the CONE/Net CONE values were last updated in 2014. The overall impact of the changes is to increase the overall reserve market revenues for a CT resource and, in particular, the expected forward reserve market revenues.

[34] *See* PJM Open Access Transmission Tariff, Common Service Provisions, Definitions, which states: "'Reference Resource' shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh."

[35] *PJM Interconnection, L.L.C., Order Conditionally Accepting Tariff Revisions, Subject to Compliance Filing*, 149 FERC ¶ 61,183 (2014), *Order on Rehearing and Compliance*, 153 FERC ¶ 61,035 (2015).

[36] *See* New York Independent System Operator, Inc., Market Administration and Control Area Services Tariff, Section 5.14.1.2.2.

[37] *See* New York Independent System Operator, Inc., Proposed ICAP Demand Curves for the 2017/2018 Capability Year and Parameters for Annual Updates for Capability Years 2018/2019, 2019/2020 and 2020/2021, filed November 18, 2016 in Docket No. ER17-386-000.

[38] Proposed NYISO Installed Capacity Demand Curves For Capability Year 2017/2018 and Annual Update Methodology and Inputs For Capability Years 2018/2019, 2019/2020, and 2020/2021, NYISO

(continued...)

G. ORTP Values

The ISO and the IMM administer a range of market power mitigation mechanisms to ensure the integrity of the Forward Capacity Market. The ORTPs are part of the buyer-side market power mitigation structure that seeks to ensure that capacity prices are not inefficiently suppressed by the uneconomic entry of subsidized new resources. The rules concerning the IMM's review of capacity supply offers for new resources are specified in Market Rule 1, Appendix A, Section III.A.21. At a high level, the rules are structured to provide that the IMM need only review those capacity supply offers "that plainly appear commercially implausible absent out-of-market revenues."[39] The ORTP benchmark values reflect the estimated net cost of entry for different resource technologies that may participate in the Forward Capacity Market.[40] In other words, the ORTPs act as a screen. Offers at or above the relevant trigger price are assumed to be competitively priced and are used in the Forward Capacity Market without further review. Offers below the relevant trigger price are subject to additional review through the process specified in Section III.A.21. Establishing the trigger prices at the low end of the spectrum of estimated costs is intended to strike a reasonable balance by not subjecting offers that are "clearly competitive" to IMM evaluation.[41]

For those resource types for which it is not possible to establish a reliable ORTP value, a default ORTP is set equal to the Forward Capacity Auction Starting Price plus $0.01/kW-month.[42] This means that the IMM automatically will review offers for that resource type in order "to protect against the exercise of buyer-side market power that could inappropriately suppress capacity prices."[43] A resource type for which an ORTP cannot be reliably calculated is likely to be based on an emerging technology about which there is insufficient cost data. Importantly, having offers subject to review by the IMM does not prevent any resource type from participating in the Forward Capacity Market. It only means that a capacity supplier

(...continued)
Staff Final Recommendations (09/15/2016) at p. 36, Table 18, Docket No. ER17-386-000 (November 18, 2016). The H-class CT net entry cost value for New York's "Central" region is $97.23/kW-year (or $8.10/kW-month), compared to the $8.04/kW-month value for New England. For further information, see, Study to Establish New York Electricity Market ICAP Demand Curve Parameters at p. 108 *et seq.*, Analysis Group, Inc. and Lummus Consultants International, Inc., Docket No. ER17-386-000 (November 18, 2016).

[39] February 12, 2013 Order at P 38.

[40] The use of resource-specific benchmarks was mandated by the Commission in an order issued on April 13, 2011 in Docket Nos. ER10-787-000 *et al*. *ISO New England Inc. and New England Power Pool Participants Committee*, *Order on Paper Hearing and Order on Rehearing*, 135 FERC ¶ 61,029 (2011).

[41] February 12, 2013 Order at P 38.

[42] Market Rule 1, Section III.A.21.1.1.

[43] February 11, 2014 Order at P 3.

submitting an offer below the ORTP level must substantiate its costs and show that the offer will not inappropriately suppress capacity prices.[44]

The ORTP review process begins with the application of screening criteria to identify the resource types for which ORTPs will be calculated. The screening process considers whether a technology has been installed in the New England region and participated in recent auctions, whether there is reliable cost information available to calculate an ORTP using a full "bottom-up" analytical approach, and whether a resource's first year revenue requirement would be below the expected Forward Capacity Auction Starting Price. After applying these criteria, ORTPs were calculated for CT, CC, onshore wind generation, energy efficiency, and Real-Time Demand Response Resources (sometimes referred to as active demand response resources). Resource-specific ORTP values were not calculated for solar photovoltaic technologies, offshore wind generation, biomass generation, or battery-storage technologies and, accordingly, offers for any of these resource types are subject to further review by the IMM.[45]

The process of calculating the ORTP values for each of the resource types that passed the screening criteria is very similar to the process used to calculate the new CONE and Net CONE values. Based on assumptions about the operating characteristics of each resource type, the gross entry costs and expected net revenues for each resource type were estimated. The ORTP was then set to the resulting net entry cost calculated for each resource type. Section 4 of the CEA Report provides a full description of the ORTP calculation process and the resulting benchmark net entry cost values for each technology examined. It is important to note that, consistent with past practice, the ORTP values reflect the low end of the competitive range of expected offers so that further review is required only for offers that do not appear to be commercially plausible absent out-of-market revenues.[46] This approach means that certain assumptions are different for ORTPs than for the CONE/Net CONE values. For example, as discussed in Section 4.D of the CEA Report, certain financial assumptions included in the ORTP calculations are more favorable (that is, result in lower net entry costs) than the assumptions that would be used for CONE/Net CONE purposes.

H. Tariff Changes Concerning the Energy and Ancillary Services Offsets

In addition to proposing the updated CONE, Net CONE and ORTP values, the ISO also is proposing relatively minor changes to the method used to calculate annual adjustments to

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[44] *See* February 12, 2013 Order at P 39, in which the Commission addressed challenges to certain assumptions reflected in the ORTPs by starting that if a resource developer "believes that its costs are lower than the applicable trigger price, it can seek a lower offer floor by submitting its unit-specific costs to the IMM."

[45] Section 4.C of the CEA Report discusses the application of the screening criteria.

[46] The Commission recognized this practice in the February 12, 2013 Order at P 38, stating: "use of trigger prices at the low end of the spectrum strikes a reasonable balance by not subjecting clearly competitive offers to IMM evaluation, but only addressing those offers that plainly appear commercially implausible absent out-of-market revenues."

those values in the years between triennial updates. The changes are discussed in Section 3.H (CONE/Net CONE) and Section 4.I (ORTP) of the CEA Report.

The general purpose of the changes is to apply a consistent adjustment method for both the ORTP and the CONE/Net CONE values, particularly for gas-fired resources (CT and CCs). Consistency is achieved by changes to the rules concerning the indices used to perform the annual adjustments. The revised provisions are in Section III.13.2.4 (CONE/Net CONE) and Section III.A.21.2(e)(4).

The revised provisions generally work as follows. For the gas-fired resources, a ratio of power prices to delivered regional natural gas prices will be calculated for the 2021/2022 settlement period using three price indices: the Mass Hub DA On-Peak futures contract price, the Henry Hub futures contract price, and the Algonquin Citygates-to-Henry Hub "basis" (or difference) futures contract price (*NB.,* the sum of the latter two contracts' prices is a conventional measure of the future annual cost of delivered natural gas in New England, and is used as such in the proposed new adjustment process). During the adjustment process, the same ratio will again be calculated using updated data for the applicable settlement period, and the percentage change in this ratio will be applied to the energy and ancillary services revenue offset for both the CONE/Net CONE and ORTP calculations.

For wind resources, which do not have a fuel component, the initial ratio and updated ratios used to adjust the ORTP value for each settlement period will be based only on the Mass Hub Day-Ahead On-Peak futures contract price. In that way, the adjustment process for wind resources will be based on that contract market's change in expected future annual wholesale energy prices in New England.

I. Use of CONE/Net CONE for Purposes of Determining Capacity Zones

In a prior order addressing the modeling of capacity zones, the Commission encouraged the ISO and its stakeholders to consider whether potential entry cost differences between zones should be a factor in determining whether a capacity zone should be modeled in the Forward Capacity Market.[47] The ISO is taking this opportunity to advise the Commission that this zonal modeling/entry cost issue has been formally discussed with stakeholders in the region, and that no further action is recommended at this time.

The ISO first discussed this issue with stakeholders at the October 2014 NEPOOL Markets Committee meeting as part of an early effort to develop zonal demand curves. The ISO again discussed the issue with stakeholders at the September and October 2016 NEPOOL Markets Committee meetings during the consideration of the CONE and ORTP Updates. At all of the meetings, the ISO recommended that entry costs not be used to model capacity zones and

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[47] *ISO New England Inc., Order Accepting Compliance Filing*, 147 FERC ¶ 61,071 at P 43 (2014) (Docket No. ER12-953-004).

explained the economic basis for the ISO's recommendation. Stakeholders did not raise substantive concerns with the ISO's explanation, nor objections to the ISO's recommendation.

At the September and October 2016 meetings, the ISO explained that the current process of modeling capacity zones uses Commission-approved, objective criteria to identify areas within New England with a potential need for additional zonal supply;[48] if there are any such areas, they are then modeled as Capacity Zones in the Forward Capacity Auction. Beginning with FCA 11, any modeled Capacity Zone will have a MRI-based zonal demand curve in the applicable FCA.

The structure of the MRI-based zonal demand curves makes it unnecessary to consider zonal Net CONE differences as a supplemental consideration in these objective criteria tests. As context, we note that if the existing capacity supply quantity in any potential import-constrained zone of the system would result in the zone's MRI-based demand curve producing price separation from the Rest-of-Pool Capacity Zone, then the objective criteria test already would result in the import-constrained zone being modeled in the Forward Capacity Auction. That is, the objective criteria tests are more stringent than the MRI-based demand curves, and can trigger modeling of import-constrained zones that will not price separate (with no change in total zonal supply).

A second element of the ISO's discussion with stakeholders is how estimated new entry cost differences would affect (or not, as it turns out) existing zonal modeling outcomes. Under the MRI-based demand curves, the (lowest) capacity quantity in a potential import-constrained zone at which there is no price separation from the Rest-of-Pool Capacity Zone is: (a) unaffected by an import-constrained zone's possible higher net cost of new entry, and; (b) less than the (highest) existing capacity quantity that would trigger the zone to be modeled under the current objective criteria tests. Thus, consideration of a potential import-constrained zone's higher net cost of new entry as a supplemental consideration in the existing objective criteria tests is unnecessary: it can be expected to change the tests' outcome (*viz.*, to model an otherwise un-modeled zone) only when no price separation should arise. An analogous set of considerations apply to export-constrained capacity zones, based on substantively similar properties (excepting the direction of the constraint).

Stated in simpler terms, adding net cost of entry differences as a supplemental consideration for whether to model a zone, in addition to the existing objective criteria tests, would not change Forward Capacity Auction outcomes. For these reasons, the ISO recommended that the existing objective criteria tests would not benefit from adding zonal net cost of entry differences as a supplemental consideration. As noted, stakeholders did not register any concerns with the ISO's recommendation on this issue.

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[48] *ISO New England Inc., Order Accepting Compliance Filing*, 147 FERC ¶ 61,071 (2014).

V. DESCRIPTION OF TARIFF REVISIONS

This section provides a guide to the Tariff revisions associated with the CONE and ORTP Updates.

The tariff changes concerning the CONE and Net CONE values are made in Section III.13.2.4. The changes replace the current stated values for CONE and Net CONE with the new updated values starting with FCA 12. In addition, the change to provide for a more consistent method of calculating the annual updates for the CONE/Net CONE and ORTP values (discussed in Section IV.H of this filing letter) requires a change to remove a clause in Section III.13.2.4 that reflects the different treatment provided under the current rules.

The Tariff changes concerning the ORTP values are made in Appendix A of Market Rule 1. In Section III.A.21.1.1, the current ORTP values are replaced with the new updated values starting with FCA 12. Section III.A.21.1.2(e)(4) contains the changes to the annual update methodology for both the CONE/Net CONE and ORTP values, as discussed in Section IV.H of this filing letter.

VI. STAKEHOLDER PROCESS

The CONE and ORTP Updates were considered through the complete NEPOOL Participant Processes. The ISO initially presented information on the CONE and ORTP Updates to stakeholders in July 2016 and continued to review the proposed updates over the next six months. On January 6, 2017, the NEPOOL Participants Committee failed to support the CONE and ORTP Updates by a vote of 49.66% in favor.[49] At a high level, there were two issues that resulted in some stakeholders not supporting the package of CONE and ORTP Updates. First, as discussed earlier, some stakeholders did not support the choice of a CT as the reference technology used as the basis for determining the CONE and Net CONE values. Second, some stakeholders did not support the capacity factor assumption and the resulting ORTP value for onshore wind resources.

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. However, the CONE and ORTP Updates do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations.[50] Notwithstanding the request for waiver, the

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[49] Pursuant to the Participants Agreement, a vote of at least 60% is required for support of any proposed Market Rule changes and a vote of at least 66-2/3% is required for support of any other proposed change. Market Rules are included in Section III of the Tariff.

[50] 18 C.F.R. § 35.13 (2014).

ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- This transmittal letter;
- Attachment 1 - Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis (the "CEA Report");
- Attachment 2 - Affidavit of Danielle S. Powers, Concentric Energy Advisors, Inc.;
- Attachment 3 - Affidavit of Keith Paul, Mott MacDonald, Inc.;
- Blacklined Tariff sections reflecting the revision submitted in this filing;
- Clean Tariff sections reflecting the revision submitted in this filing;
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Section I above, the ISO requests that the changes become effective on March 15, 2017.

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 available on the ISO's website at: https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. 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 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 Section VII of this transmittal letter.

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 changes is evidenced by this filing.

35.13(b)(7) – The ISO 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.

35.13(c)(1) – The changes submitted 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) – 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 revision filed herein.

VIII. CONCLUSION

For the reasons discussed in this transmittal letter, the ISO requests that the Commission accept the CONE and ORTP Updates, without modification, to become effective on March 15, 2017.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachment 1

ISO-NE CONE and ORTP Analysis

An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 (“FCA-12”) and forward

January 13, 2017

CONCENTRIC ENERGY ADVISORS

www.ceadvisors.com

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SECTION 1:
EXECUTIVE SUMMARY

This report contains the results of the estimates of both: i) the Cost of New Entry ("CONE") and the CONE net of expected revenues ("Net CONE"), and ii) the technology specific Offer Review Trigger Prices ("ORTP") for use in New England's Forward Capacity Market ("FCM"). As more fully explained in this report, the CONE and Net CONE values are parameters used in the Forward Capacity Auctions ("FCA") that are intended to reflect the compensation a cost effective new entrant would need from the capacity market (net of expected revenues) in the first year of operation to recover its capital and fixed costs under long-term equilibrium conditions, given reasonable expectations about future market conditions and cost recovery assumptions. Estimating Net CONE is done from the perspective of a hypothetical unit of a particular technology type in a particular location in New England, which is referred to as the "reference" unit. The ORTP values are used as a "screen" for potentially new uncompetitive resource offers in an FCA to protect against the exercise of buyer-side market power that could inappropriately suppress capacity prices. It is a benchmark price down to which a new capacity supply resource can offer freely without justification to ISO New England Inc.'s ("ISO-NE") Internal Market Monitor ("IMM").

ISO-NE contracted with Concentric Energy Advisors, Inc. ("Concentric") to conduct an independent analysis of the CONE/Net CONE and ORTP values for the FCM 2021/2022 Commitment Period (June 1, 2021 through May 31, 2022). Concentric and its subcontractor, Mott MacDonald ("MM"), worked together to develop the recommendations presented in this report. To arrive at these results, we considered relevant market and technology issues, screened several technologies, and closely evaluated those that met specified CONE and ORTP screening criteria. This evaluation included a detailed analysis of technical specifications, capital and operating costs, and future market conditions to calculate expected revenues and arrive at recommended CONE/Net CONE and ORTP values.

Based on our analysis, we recommend that the simple cycle frame combustion turbine be used as the reference technology for FCA-12, which is the relevant auction for the 2021/2022 Commitment Period. The choice of reference unit has a large impact on the Net CONE value and is critical to ensuring that the capacity market will procure capacity sufficient to meet the region's resource adequacy requirement cost effectively. The simple cycle frame combustion turbine is substantially less expensive than the combined cycle combustion turbine and the aeroderivative machines, and is an established technology in New England. The simple cycle frame combustion turbine machine has participated and cleared in the most recent FCAs, as shown in Table 1.

Table 1: Proposed Simple Cycle and Combined Cycle Projects in New England

Power Plant	Generation Technology	Estimated In-Service Date	Turbine Manufacturer	Turbine Type	State	Approx. Nameplate Capacity (MW)	Current Operating Status
Salem Harbor	Combined Cycle	6-2017	General Electric	7F 5-Series	MA	674	Under Construction
West Medway II	Gas Turbine	4-2018	General Electric	LMS100PA+	MA	200	Advanced Development
Towantic Energy Center	Combined Cycle	5-2018	General Electric	7HA.01	CT	785	Under Construction
Wallingford Energy (LS Power)	Gas Turbine	6-2018	General Electric	LM6000	CT	90	Early Development
Bridgeport Harbor Station	Combined Cycle	6-2019	General Electric	TBD	CT	485	Early Development
Canal 3	Gas Turbine	6-2019	General Electric	7HA.02	MA	333	Early Development
Clear River Energy Center	Combined Cycle	6-2019	Not announced	TBD - G, H, or J Class	RI	1000	Early Development

The active participation of simple cycle frame combustion turbines in recent FCAs differs from the situation that existed when the CONE/Net CONE study was conducted in 2014, where the combined cycle combustion turbine was the recommended reference technology because there were no simple cycle combustion turbines proposed or participating in the FCM at that time. Stakeholders expressed concern regarding the use of the simple cycle combustion turbines as the reference technology and the non-linear reliability risk between understating and overstating Net CONE under the current demand curve design. Setting aside the fact that the new zonal demand curves mitigate these concerns, our mandate for this CONE/Net CONE study was to evaluate the compensation a hypothetical new entrant would need under long-term equilibrium conditions to enter the market, and recommend the new entrant reference technology.

Given that the market has revealed that the simple cycle technology is a cost-effective technology that has gained commercial acceptance and is economically viable in New England, we believe that the simple cycle frame combustion turbine appropriately balances relevant considerations – it is the most economic and proven technology that was evaluated, and is actively being developed in the region. The results of our CONE/Net CONE analysis is shown in Table 2.

Table 2: Net CONE Summary for Candidate Reference Technologies (2021$)

Reference Technology	Installed Capacity (MW)	Installed Cost (000$)	Installed Cost ($/kW)	ATWACC (%)	Fixed O&M ($/kW-mo)	Gross CONE ($/kW-mo)	Revenue Offsets ($/kW-mo)	Net CONE ($/kW-mo)
1x1 7HA.02 (CC)	533	$598,958	$1,124	8.1	$5.01	$15.62	$5.62	$ 10.00
1x0 7HA.02 (CT)	338	$304,179	$900	8.1	$3.21	$11.35	$3.31	$ 8.04
2x0 LM6000 PF+ (Aero)	94	$198,363	$2,110	8.1	$6.96	$25.98	$3.63	$ 22.35
1x0 LMS100PA (Advanced Aero)	103	$174,644	$1,696	8.1	$5.75	$21.03	$3.67	$ 17.36

Similarly, we have conducted an evaluation of resources that have or are expected to participate in the FCM and have an ORTP above the expected auction starting price. Based on the CONE/Net CONE analysis for the simple cycle frame combustion turbine and combined cycle combustion turbine with appropriate modifications to assumptions to reflect the low end of the competitive range, and a detailed analysis of other resources meeting the stated screening criteria, we recommend the resource specific ORTPs shown in Table 3 below.

Table 3: ORTP Summary for Specific Resources (2021$)

Reference Technology	Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost (000$)	Installed Cost ($/kW)	ATWACC (%)	Fixed O&M ($/kW-mo)	Gross CONE ($/kW-mo)	Revenue Offets ($/kW-mo)	ORTP ($/kW-mo)
Combined Cycle	533	533	$591,266	$1,109	7.3	$3.87	$13.48	$5.62	$ 7.856
Combustion Turbine	338	338	$299,123	$885	7.3	$ 2.47	$9.81	$ 3.31	$ 6.503
Onshore Wind	52	15.6	$146,246	$ 2,812	7.3	$5.30	$30.55	$19.52	$11.025
Energy Efficiency	1	1	N/A	N/A	7.3	$ -	$35.97	$38.13	$ -
Large DR	0.5	0.5	N/A	N/A	7.3	N/A	$1.01	N/A	$ 1.008
Mass-Market DR	0.001	0.001	N/A	N/A	7.3	N/A	$7.56	N/A	$ 7.559

SECTION 2:
INTRODUCTION

A. BACKGROUND

ISO-NE ensures that sufficient resources are available to meet future demand for electricity through a capacity market mechanism. The FCM is a long-term market that assures resource adequacy, locally and system-wide, and is designed to promote economic investment in new and existing supply and demand resources where and when they are needed. Under this market design, auctions are held annually, three years ahead of the Capacity Commitment Period (June 1, XX through May 31, XX+1), which is intended to provide for a planning period for new entry to allow potential new capacity to compete in the auctions. The Capacity Commitment Period is a year-long period that corresponds to the ISO-NE power year. Thus, sellers commit to provide capacity for one year—for example, June 1, 2021 through May 31, 2022—three-plus years in advance of the Capacity Commitment Period.

The FCA utilizes a downward-sloping demand curve designed to procure sufficient capacity to maintain resource adequacy and reduce price volatility over time, yielding smaller swings in capacity prices when the market moves from conditions of excess supply to periods when new capacity resources are needed. The demand curve is expressly dependent on: (1) the estimated gross entry cost, or CONE for a new capacity resource; and (2) the estimated gross entry cost net of revenues from energy, reserve, and other markets or Net CONE. Net CONE is the levelized capacity revenue that a new resource would need in its first year of operating to be economic, given reasonable assumptions about net revenues. Estimating the CONE/Net CONE values accurately in order to represent the true value that new entrants would need to enter the market is an important design criterion for the sloped demand curve to achieve desired reliability objectives.

In addition, the FCM design includes a mechanism to protect against the price suppressing effects of uncompetitive new resource offers. This mechanism subjects all new entrants in the FCA to a benchmark known as the ORTP. The ORTP acts as a screen for potentially uncompetitive offers from new resources in an FCA. It does so by setting benchmark prices which approximate the Net CONE for each resource, but represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. New supply offers above the ORTP level are presumed to be competitive and not an attempt to suppress the auction clearing price, while offers below the ORTP level must be reviewed by the IMM pursuant to a unit-specific review process. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

B. SCOPE AND OBJECTIVES

Concentric and MM were retained by ISO-NE to conduct both a CONE/Net CONE study as well as an ORTP study to determine appropriate CONE, Net CONE, and ORTP values for FCA-12, as well as a review of the indices to be used for escalating costs and revenues so that ISO-NE can update the CONE, Net CONE and ORTP values for FCA-13 and FCA-14.

For the calculation of CONE and Net CONE, ISO-NE's Tariff requires the following:

> *"CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply."*
>
> *"Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e)…."*[1]

For the calculation of ORTP values, ISO-NE's Tariff requires the following:

> *"The Offer Review Trigger Price for each of the technology types… shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply".*[2]

Concentric and MM have conducted both studies simultaneously in an open and transparent process with stakeholders and ISO-NE. Key assumptions and issues were brought to stakeholders for input and feedback in five separate meetings in front of the NEPOOL Markets Committee. These meetings provided important feedback and direction on concepts and metrics relevant to the study process, and provided guidance for consideration of, and recommendations on, key study issues and outcomes.

C. APPROACH

The objective of the CONE/Net CONE and ORTP studies is to calculate values for FCA-12 for the 2021/2022 Capacity Commitment Period. The CONE/Net CONE values must reflect the price needed to attract sufficient new capacity under long-term equilibrium conditions. Consistent with guidance from ISO-NE and the Federal Energy Regulatory Commission ("FERC"), the recommended ORTPs are set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues.

The study process consisted of the four basic tasks outlined below and further described in this report:

- **Resource Screening and Selection.** The first step in the process was the development of screening criteria for the selection of resource types for which to calculate a CONE/Net CONE value and ORTP benchmark values. Those resources that passed the screens were subject to a full evaluation of costs and revenues over the expected life of the facilities.
- **Calculation of CONE.** For each of the selected technologies for the CONE/Net CONE and ORTP analysis, we developed technical specifications, installed capital costs and operating costs over the 20-year expected life of each facility (11 years for Energy Efficiency and

[1] Market Rule 1 Section III.13.2.4.
[2] Market Rule 1 Section III.A.21.1.2.

Demand Response Resources). Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we calculated a first-year revenue requirement that ensured the recovery on and of investment costs. We adjusted selected operating costs, as well as our financial assumptions, for the ORTP calculation to reflect a resource with output under contract consistent with Tariff requirements and to achieve the "low end of the competitive range" objective.

- **Calculation of Expected Revenues.** We estimated expected revenues for each of the selected technologies, including energy revenues (net of variable costs), ancillary service revenues, renewable energy credit ("REC") revenues and pay for performance ("PFP") revenues. The calculation of expected revenues included a review of historic data, an analysis of expected future market conditions, the development of an energy price forecast using a production cost simulation model, a review of current and future expected REC prices, and data provided by ISO-NE on expected future shortage events under long-term equilibrium conditions.
- **Calculation of Net CONE and ORTP.** Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market in the first year of operation (2021) to determine Net CONE and ORTP values for each resource. For generation resources, capital costs, operating costs, expected non-capacity revenues, and assumptions regarding depreciation, taxes and discount rate were input into a capital budgeting model which was used to calculate the break-even contribution required from the FCM to yield a discounted cash flow with a net present value ("NPV") of zero for the resources. The Net CONE value and ORTP value were set equal to the year-one capacity price output from the model over the life of the facility. The difference between the Net CONE values and the ORTP values is the assumption of costs and revenues reflecting a low end of the competitive range for the ORTP values.

For Energy Efficiency, the methodology used to calculate the ORTP value was the same as that used for generation resources, except that the methodology discounted cash flows over the 11-year contract life. However, the model took into account all costs incurred by the utility and end-use customer to deploy the efficiency measure. In addition, the model reflected the end-use customer energy savings associated with the energy efficiency programs, and discounted the cash flows over the 11-year life of the energy efficiency measure.

For Demand Resources, the methodology used to calculate the ORTP value was the same as that used for new generation resources, except that the methodology discounted cash flows over the 11-year contract life. For Demand Resources composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs included new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources primarily composed of mass market measures that do not use pre-existing equipment or strategies, incremental costs included equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

Each of these tasks involved a detailed review of historical data, forecast of future prices, and professional judgement in order to calculate estimated values for each technology. These parameters were informed through consultation with ISO-NE and stakeholders in order to ensure the effectiveness and appropriateness of the methods and data used.

D. REPORT CONTENTS

The balance of the report begins with a detailed description of our CONE/Net CONE study and results, including the screening process, development of technical specifications, calculation of capital costs and operating costs, approach to and calculation of financial assumptions, development of net revenue forecasts and final CONE/Net CONE values for candidate reference technologies and the recommended reference technology.

Following the CONE/Net CONE study description and results, the ORTP study is presented. The ORTP study was largely based on the CONE/Net CONE study for gas-fired resources, with some cost and financial assumptions modified to reflect the low end of the competitive range objective. The ORTP study also included a screening of other resource types expected to enter the FCM, and an analysis and recommended values for those resources that passed the screening criteria.

SECTION 3: CONE/NET CONE STUDY

A. RESOURCE SCREENING CRITERIA, PROCESS AND SELECTION

We began the CONE/Net CONE study by recognizing the variety of resources that currently participate in the FCM, and the establishment of technology screening criteria to focus the analysis on those resources that are appropriate as candidate reference technologies for determining Net CONE. Based on guidelines approved by the FERC in the last calculation process, we used the following criteria for selecting the appropriate candidate reference technologies for the evaluation of Net CONE values:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions; and
2. Must have reliable cost information available to calculate a CONE value using a full "bottom up" analytical approach.

The first principle, that the reference technology must be economic for merchant entry under long-term equilibrium conditions, recognizes that uneconomic technologies will have a higher Net CONE than other alternatives and would set Net CONE higher than required to meet established reliability objectives. In order to determine whether the reference technology is likely to be economic as part of the long-term equilibrium, the resource must meet the following criteria: i) the resource must be of a size that can be used to meet resource adequacy requirements; ii) the resource must have demonstrated commercial interest by merchant developers based on the information available for projects recently completed, under construction, or in the interconnection queue in New England; and iii) the resource must have an estimated Net CONE that is not so high that the technology is unlikely to be part of the long-term equilibrium. As different resource types provide different services other than capacity (e.g., baseload versus peaking operations), several technologies could be economic with the same Net CONE in a long-term equilibrium. However, market conditions will change over the forecast period, such that different technologies can have the lowest Net CONE value over time. For this reason, reference technologies that are clearly expected to be a part of the long-term mix of additions should not be excluded as a candidate reference technology, even if their Net CONE value may be temporarily slightly higher than other technologies.

The second principle is that the reference technology must have reliable cost information available to calculate a CONE/Net CONE value using a full "bottom up" analytical approach. Estimating CONE/Net CONE values requires the development of assumptions about resource specifications, the analysis of potential costs and revenues, the estimation of financial parameters and risks, and the execution of subjective decisions in developing the Net CONE values. Therefore, it is critical that enough data is available to determine a technology's Net CONE with a reasonably low level of uncertainty.

Several different resources were considered for an evaluation, including gas-fired resources, coal-fired resources, nuclear resources and various renewable resources. Gas-fired resources passed the screening criteria, as they have been proven to be economic for new entry and have numerous sources of historical operating data. As a result, we focused on gas-fired resources in both simple cycle and combined cycle configurations as the appropriate technologies for the CONE/Net CONE analysis.

In terms of the simple cycle technologies, we considered both frame machines and aeroderivative machines. For frame machines, we considered the following key features:

- Can provide reliable generation to the grid for a low capital cost;
- Can be installed with fast start capability;
- Technology being continuously developed and improved by the manufacturers;
- Usually installed for peak power production;
- Industrial design intended for long term operation at high efficiencies; and
- Currently being installed in New England.

The simple cycle frame machines that were considered as candidate simple cycle technologies are shown in Table 4 below.

Table 4: Simple Cycle Frame Machines

Frame Technology	Justification
GE7HA.02	• GE's newest large frame machine • Currently scheduled to be next in GE test rig • Highest output available for a Frame GT • GE guaranteed performance
Siemens 8000H	• Largest installed experience base for large frame gas turbines • Smaller and less efficient than GE 's or MHI's newest machines • Currently working on a new larger more efficient machine
MHI M501GAC	• Air cooled large frame gas turbine from previous generation technology
MHI 501JAC1	• New entry into simple cycle market • Not yet installed in simple cycle configuration • Best heat rate available for a frame machine • Smaller, more expensive from an installed $/kW perspective, small installed base in United States
Other Frame Machines	• MHI/Hitachi HH100 targets 7EA retrofits as a "drop-in" replacement • Alstom/GE GT-24 not being marketed aggressively by GE

As a result of the review of the above simple cycle frame combustion turbine options, we chose the GE7HA.02 as the frame combustion turbine model on which to conduct a full CONE/Net CONE evaluation. Although not yet in commercial operation, a project using this technology is currently being developed at a generating facility in New England and is the most current frame technology commercially available for simple cycle operation.

For aeroderivative machines, we considered the following key features:

- Fastest to market and fastest to engineer;
- Size makes them more expensive in $/kW installed;
- Multiple LM6000 plants are operating in New England with the LM6000 PF+ being the latest version; and
- Can be converted to combined cycle if originally arranged properly.

The aeroderivative combustion turbine machines that were considered as candidate simple cycle technologies are shown in Table 5 below.

Table 5: Simple Cycle Aeroderivative Machines

Aeroderivative Technology	Justification
GE LM6000	• One of the most widely installed machines in New England • LM6000PF+ is the latest dry-cooled version
LM2500	• High $/kW installed cost • Often utilized in combined heat and power or industrial process applications
Rolls Royce Trent	• Viable option to LM6000 family
MHI Pratt & Whitney FT8 Swiftpac	• Less efficient machine with small New England installed base
Siemens SGT 800	• Efficient competitor to LM6000 and Trent with small installed base in NE
Solar Titan 250	• Small machine with high heat rate and small installed base in NE
GE LMS100PA	• Wet Cooled machine that is designed with some aeroderivative turbine sections and some frame machine sections • Only advanced aeroderivative machine available • Most efficient simple cycle machine available

As a result of the review of the above aeroderivative machines, we chose the GE LM6000PF+ and the GE LMS100 PA on which to conduct a full CONE/Net CONE evaluation. These machines are currently installed in New England and represent a commercially acceptable and cost effective technology.

Finally, for the combined cycle technologies, we considered the following key features:

- Can provide reliable generation to the grid;
- Can provide the best thermal efficiency available;
- Utilizes the largest and most efficient gas turbine technology available for combined cycle applications;

- Current frame designs are undergoing a step-change improvement in output and efficiency, and
- Currently being installed in New England.

The combined cycle combustion turbines that were considered as candidate peaking technologies are shown in Table **6** below.

Table 6: Combined Cycle Combustion Turbines

Frame Technology	Justification
GE7HA.02	• Latest air cooled large frame gas turbine • Highest output available for a Frame GT as of June 2016 • Currently scheduled to be next in GE test rig • Performance guaranteed by GE
GE 7HA.01	• Currently offered for sale, but expected to be replaced by the 7HA.02 due to improvements in capacity and efficiency • Currently in operation
GE 7FA - .04 thru.06	• Will continue to be offered for sale, but are smaller and less efficient than the 7HA.02 technologies
Siemens 8000H	• Largest installed experience for large frame gas turbines • Smaller and less efficient than GE's or MHI's latest technology machines
Siemens 8000J? – New name to be determined	• Siemens is working on their next generation machine, but it is not yet available
Siemens F Class Machines	• Not expected to be available in the 2019-2020 time- frame
MHI M501J and JAC1	• M501JAC1 o Best heat rate available for a large frame machine, comparable output to a GE7HA.02 o Utilizes an external compressor to provide additional cooling o Currently in operation in MHI Tea Point facility in Takasago, Japan o Performance guaranteed by MHI • M501J is a steam cooled large frame gas turbine o Slightly lower capacity than the M501JAC1, but with equal heat rate • M501JAC o Original air cooled J technology design o Better performance than F or G class technology o Slightly more expensive from an installed \$/kW perspective, small installed base in United States, and New England in particular. o Heat rate significantly worse than larger frame machines, driving installed \$/kW costs higher
Other frame machines	• MHI/Hitachi HH100 and Alstom/GE GT-24 not being marketed by GE in the U.S. • Siemens SGT Family – Not a large installed base in New England, not being aggressively marketed by Siemens

As a result of the review of the above combined cycle combustion turbine options, we chose the GE 7HA.02 as the combined cycle turbine model on which to conduct a full CONE/Net CONE evaluation. This machine is currently being installed in New England in a combined cycle configuration and therefore represents a commercially acceptable and cost effective technology.

We have noted that all of the generating resources that underwent full evaluation utilize turbines developed by GE. This is because GE clearly has most or all of the market share for new turbines being developed in New England at this time. Other gas-fired resources that use turbines from other manufacturers were also considered, but were not fully evaluated since they did not reflect the level of activity in New England demonstrated by GE.

We applied the same screening criteria for consideration as a candidate reference technology to other resources that are currently participating in the FCM. These resources did not pass our screening criteria, as shown in Table 7 below.

Table 7: Resource Screening Results

	Economic For Merchant Entry	Reliable Cost Information for a Full Bottoms Up Approach
On-Shore Wind	• Higher cost than other CONE alternatives without a contract for output	• Inconsistencies in project size and arrangement that differentiate projects • A "Standard Design" more than likely would not fit multiple projects
Off-Shore Wind	• Since only one project is in commercial operation in the US, the economics for merchant entry are unknown	• Since only one project is in commercial operation in the US, there is insufficient data to perform a full analysis
Coal	• Unlikely to be developed in New England	
Nuclear	• Unlikely to be developed in New England	
Solar	• Higher cost than other alternatives due to low solar irradiance and high land cost	• Current significant differences in costs and incentives result in inconsistent data
Large-Scale Battery	• Since no projects are in commercial operation in the US, the economics for merchant entry are unknown	• Since no projects are in commercial operation in the US, there is insufficient data to perform a full analysis

B. KEY ASSUMPTIONS

General assumptions utilized in the CONE technology screening that are applicable to all technologies include assumptions regarding location, plant configuration, interconnections to the gas and electric distribution systems, dual fuel capability, and environmental control capabilities. Each assumption is described below.

1. Location

Locations were screened based on two primary criteria: i) locations where energy infrastructure already exists to allow ready access to the electric and gas distribution networks; and ii) locations in which retirements were likely to occur. Preference was given to locations meeting the first and second criteria that were located in close proximity to high-demand areas.

Applying these criteria resulted in the identification of Southeastern Connecticut and Bristol County, Massachusetts as likely candidates. Because Bristol County has fewer projects in development than Southeastern Connecticut, and because significant amounts of capacity are expected to retire in and around Bristol County, the Bristol County location was chosen for the CONE analysis.[3]

2. Greenfield versus Brownfield

Both greenfield and brownfield sites were considered since both types of sites are currently being developed in New England. Due to the fact that brownfield sites are highly variable in terms of characteristics and the extent of the re-use of existing equipment, the ability to reasonably estimate development costs for brownfield sites was challenging and uncertain. Because of their potentially unique re-development costs, brownfield sites tend to be an unreliable predictor of future entry costs under long-run equilibrium conditions, as the screening criteria require (see Section 3.A). Therefore, we assumed that a new entrant would be located on a greenfield site.

3. Plant Configuration

Projects being currently developed in New England provide important data points on plant configurations viewed as most viable by the market. A sampling of recent gas-fired projects developed in New England is shown in Table 8 below. Note that these projects represent a mix of combined cycle and simple cycle frame technologies, and all use turbines manufactured by GE. Additionally, all projects are located in Southern New England.

[3] Brayton Point and Pilgrim Nuclear Generating Station are each expected to retire prior to 2020. Brayton Point is located in Bristol County and Pilgrim is located in neighboring Plymouth County. The combined capacity of the two plants is in excess of 2,200 MW.

Table 8: Recent Projects Developed in New England[4]

Plant Name	Type	Estimated In-Service Date	Turbine Manufacturer	Turbine Type	Location	Nameplate Capacity (MW)
Salem Harbor	CC	2017	General Electric	7F 5-Series	MA	674
West Medway II	GT	2018	General Electric	LMS100PA+	MA	200
Towantic Energy Center	CC	2018	General Electric	7HA.01	CT	785
Wallingford Energy	GT	2018	General Electric	LM6000	CT	90
Bridgeport Harbor	CC	2019	General Electric	TBD	CT	485
Canal 3	GT	2019	General Electric	7HA.02	MA	333
Clear River Energy Center	CC	2019	Not announced	TBD - G, H, or J Class	RI	1,000

4. Interconnection Assumptions

Based on a review of generating plants currently in development and also the availability of gas and electric infrastructure in Bristol County, a 2-mile interconnection to both the gas and electric grids was assumed. The electrical interconnection was assumed to connect to the 345kV system. Required network upgrades were also evaluated based on data provided by ISO-NE on technical upgrade specifications associated with recently developed projects in New England. Based on this information, network upgrade costs were calculated for each reference technology.

5. Dual Fuel Assumptions

The candidate reference units were assumed to have backup fuel in the form of No. 2 oil. No. 2 oil is the most commonly installed backup fuel in New England, and publicly available data on the cost to install backup capability and to operate the plant on oil are available. Fuel security consistent with the existence of backup fuel is a prerequisite of this assumption.

6. Environmental Assumptions

All plants are designed to be in compliance with federal requirements and regional requirements. This includes Carbon Monoxide ("CO") Catalysts and Selective Catalytic Reduction ("SCR") equipment for all simple cycle and combined cycle designs. Dry cooling is also utilized for ease of environmental permitting.

7. Cooling System

The plants are designed with dry cooling for primary heat sinks. This was done to maximize potential installation sites and to ease permitting. The simple cycle plants utilize dry fin fan coolers. The

[4] SNL Financial.

LMS100PA machine utilizes a wet cooled intercooler. The combined cycle plant is designed with an air-cooled condenser. While there are more thermally efficient designs available, air cooled condensers are the easiest to permit, do not require significant makeup water, and can be utilized on most sites where reasonable space is available.

8. Supplemental Firing

Supplementary firing was provided for the combined cycle design. The duct burners can be fired to a 1250° F burner exit gas temperature. This firing rate provides additional peaking capacity while not increasing the cost of the heat recovery steam generator and the steam turbine, or negatively impacting the base combined cycle heat rate significantly.

9. Evaporative Cooling

Evaporative coolers were included to provide improved performance on warm low humidity days. Evaporative cooler effectiveness was set at 85%, which is considered reasonable for standard evaporative cooler technology.

10. Operating and Maintenance Costs

LAND LEASE

Land was assumed to be leased and recorded as a fixed operation and maintenance ("O&M") expense. Based on a review of industrial leasing costs, we assumed $25,000/acre based on the need to be close to gas and transmission interconnection. This lease rate was multiplied by the estimated land size.

PROPERTY TAXES

Property taxes were assumed to be 3% as more fully described in Section 3.C.

INSURANCE

Insurance costs were assumed to be 0.6% of the overnight capital costs per year, consistent with the assumption in the 2013 CONE study, which we continue to believe is reasonable.

A summary of assumptions applicable to all reference technologies is shown in Table 9.

Table 9: Key Assumptions

Key Assumptions	
Location	Bristol County, MA
Electric Interconnection	2-mile electrical interconnection (to 345 kV system) plus network upgrades
Gas Interconnection	2-mile gas lateral plus metering station
Dual Fuel	No. 2 oil for backup
Environmental Controls	Selective Catalytic Reduction CO catalyst
Cooling	Dry Cooling for the frame units and aeroderivative Wet Cooling for the advanced aeroderivative

C. APPROACH TO DETERMINATION OF CAPITAL COSTS

MM, in partnership with Concentric, prepared capital cost estimates for the four candidate reference technologies based on modern construction techniques and materials for electricity generating stations and related facilities. MM developed the major equipment costs, field construction labor hours and quantities to be used for the creation of the cost estimates from the comprehensive MM power plant cost estimating database along with information contained in the GT PRO cost system for power plants of the size and configuration selected for this project. The MM cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle frame, combined cycle, and aeroderivative projects.

The MM cost estimating database was utilized for contractors submitting quotes "at-risk," either for the proposal itself or to crosscheck the bid the contractor had developed itself, and for developers and owners to check bids they receive. Many of the projects also include as-built cost details. The database also includes work specific information which generally addresses the civil work associated with a generation project, such as crew and construction equipment required for concrete work. The database is maintained and updated on a regular basis as new project cost estimates are prepared and information and data is received from our clients indicating the results of our work.

As a result of the selected geographic location for all of these projects just South of Boston in Bristol County, and possible competition from other projects for labor, the cost estimates include scheduled overtime in order to attract the most productive craft labor staff. All four cost estimates were based on a fifty-hour per week schedule for the journeymen. This is also based on past-experience throughout the country, where many projects start as a forty-hour work week and eventually become sixty-hour week work schedules with the construction crews working six ten-hour days per week. It is common practice to always include overtime costs on major projects in order to avoid issues during construction. In addition to the fifty-hour work week, some casual overtime was also included in each of the estimates to cover such items as unloading deliveries late in the day to avoid extra charges for the delivery vehicle, pulling electrical cable at night and the potential need to make some installations or modifications on a fast turnaround basis so that other crews can get into an area to complete their work.

1. DIRECT COSTS

MAJOR EQUIPMENT

Major equipment was priced based on the MM cost database documentation along with information obtained from our clients that have constructed a large number of electric generating plants. The MM database is kept current and is checked against market conditions for the time frame basis of the cost estimates. For any specialized major equipment that is not contained in the cost estimate database, MM clients and/or the specialty manufacturers involved in that type of major equipment supply were consulted. The MM cost estimates contain detailed information where each piece of major equipment is identified and priced accordingly.

Freight costs for the major equipment are generally included within the unit major equipment costs in the direct cost section of the cost estimates. We included freight costs in the indirect cost section of the cost estimates for a small amount of major equipment and bulk materials where we were unable to obtain shipping costs from a supplier. In those instances, freight costs were based on MM estimating experience. Vendor representative costs were included either with the value of the major equipment or listed separately in the indirect cost portion of the cost estimates.

BALANCE OF PLANT MATERIALS

Balance of plant bulk material quantities were developed from the MM selected cost estimate model[5] for this project as well as information from other MM power projects. Bulk quantities and sizes were adjusted to suit the assumed major equipment locations. Sizes of the various components were also adjusted to suit the varying sizes of the plant capacities as necessary, based on our experience and as indicated on the information developed for this analysis.

The Balance of plant materials were priced based on market conditions and prices in effect in the U.S. with adjustments to suit any special conditions that may apply in the Bristol County, Massachusetts area. Concrete supply is the one item that is particularly influenced by local costs.

Freight costs for the balance of plant materials were included within the unit material costs for the material in the direct cost section of the cost estimates. Where the pricing developed excluded freight costs, these costs were included in the indirect cost section of the estimates.

CONSTRUCTION LABOR

Labor rates were based on union labor rates for the Bristol County, Massachusetts area. The construction labor rates used in the cost estimate were composite craft labor rates for approximately 35 various crafts and included all fringe benefits, worker's compensation costs and all other required insurances and taxes. Working foreman costs were built into the labor rates while non- working general foreman costs were included separately in the construction management indirect cost

[5] An estimate for a previously estimated Power Plant was used to layout the framework for the estimate. That framework is referred to here as the "model."

section of the cost estimates. The construction labor rates used for the various crafts were included in a separate section as part of this estimate.

Field labor productivity was calculated based on field construction labor conditions for the Bristol County, Massachusetts area. These productivity values are supported by previously completed projects in the general area in which the plant would be located and for which MM has experience, as well as from previously prepared construction site surveys in the Northeast.

2. ESTIMATE DETAILS BY MAJOR CATEGORY

MAJOR EQUIPMENT FIELD INSTALLATION LABOR

Field construction installation labor hours for major equipment installation were developed from MM's experience in estimating other projects. MM's cost estimate model information and discussions with major equipment manufacturers as to installation conditions and component pieces associated with their equipment were also considered. All labor hours were adjusted to suit anticipated productivity levels associated with working in the Bristol County, Massachusetts area. As noted above, productivity values used in the study are consistent with MM's experience with similar types of construction projects in the general area.

SITE WORK

The Bristol County site location is anticipated to require only a minimal amount of additional fill since a specific location within the county was not identified and cut and fill measurements, therefore, could not be quantified. As noted above, pilings for foundations were not considered for the same reason as explained for minimal cut and fill operations.

The cost estimates include site drainage, a firewater loop system, the installation of new underground piping, new electrical duct banks and manholes, sanitary sewer piping, miscellaneous light site demolition, erosion control, excavation and backfill for the new foundations, site fencing, roadwork, site restoration and landscaping.

The cost estimates include utility tie-ins at the fence. The final paving of roads was assumed to be accomplished at the conclusion of construction activities.

CONCRETE

Concrete quantities were developed from information contained in the MM cost estimate model adjusted to expected conditions considering the major equipment required. Construction labor hours for concrete installation were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

Major concrete work in this section of the cost estimate includes the gas turbine foundation, the SCR foundation, a firewall for the main transformers, a stack foundation, building foundations, pump foundations and the switchyard area.

MASONRY

Masonry quantities were developed from information available from the MM cost estimate model and assumed building sizes. The major elements of work contained in this section include both interior and exterior concrete masonry unit walls where needed, scaffolding, and all grouting costs for major equipment, and structural steel base plates.

Field construction labor hours for masonry work were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

STRUCTURAL STEEL/METALS

Structural steel quantities were developed from information available from other MM projects of similar size, as well as the MM cost estimate model used for this project. Field construction labor hours for steel installation were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

Major structural steel work in this section of the cost estimate includes structural and supplementary steel. Platforms, grating, handrails, ladders, anchor bolts, and prime coat painting of the steel are also included unless any of these items are supplied by the manufacturer of the major equipment.

BUILDINGS

Material quantities for buildings were developed from building information developed by MM as well as the MM cost estimate model used for this project. As noted, structural steel for buildings is included in the structural steel/metals section of the cost estimate unless the building is a pre-engineered structure. This section consists of the siding, roofing, doors, carpentry, wallboard, acoustical treatment, resilient flooring, fire protection, plumbing and HVAC requirements for the buildings on the project.

The buildings required on this project that are included in this section are the administration/control/machine shop/warehouse building and a guard house.

Field construction labor hours for the building work were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

PIPING

Piping quantities contained in the MM cost estimate model were adjusted from the assumed locations of buildings and major equipment components.

Piping systems included in this section of the cost estimate include auxiliary cooling water, feedwater, fuel gas, lube oil, fuel oil, wastewater, service water, raw water, demineralized water, sampling, process and instrument air and mixed chemicals.

Field construction labor hours for the piping systems were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

ELECTRICAL

Electrical quantities were developed from the assumed locations of buildings and major equipment components. In addition, the MM cost estimate model was utilized to determine cable, conduit and cable tray sizes and lengths of a number of required electrical services.

Electrical categories included in this section are site electrical work, power/control and instrumentation for cable and conduit requirements, controls needed for interconnection to the system, area lighting and service requirements, building area lighting and services, public address system, building fire alarms, and a grounding system.

The site electrical section includes site lighting, surveillance equipment, lightning protection, cathodic protection, heat tracing and aviation lighting for the stack.

Field construction labor hours for the electrical systems were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

INSTRUMENTATION

Instrumentation quantities were developed from reviewing MM's experience with other projects and the MM cost estimate model utilized for this cost estimating effort.

The categories contained within this section include the installation and supply of contractor furnished instruments, loop checks and functional check out, instrument stands and material handling and calibration. All instrumentation and control cable, conduit and cable tray associated with the instruments are included in the electrical section of the cost estimate.

Field construction labor hours for the instrumentation systems were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

INSULATION

Estimates for insulation include allowances for both piping and major equipment insulation. MM relied on experience with other projects to develop expected quantities for this project. Information contained in the MM cost estimate model was also utilized in arriving at the allowances selected for use in the cost estimates. Insulation and electrical heat trace required for a cold climate condition were included from the cost estimate model utilized for this project.

PAINTING

This section contains all of the painting, sealer and epoxy requirements for the project. Included in this estimate is painting of the masonry walls, painting of wallboard, floor sealer, epoxy coating, finish painting of all steel with two coats over shop-applied primer coat, touch up painting of major equipment, and painting of all uninsulated steel piping.

3. INDIRECT COSTS

CONSTRUCTION MANAGEMENT

This section of the cost estimate includes the planned construction management team for the Engineering, Procurement and Construction ("EPC") Contractor. All owner construction management costs as well as other categories of owner's costs are included in this cost estimate. Costs that are included consist of a construction manager; an assistant construction manager; civil, mechanical, structural, electrical and instrument and controls ("I&C") superintendents; a field office manager; engineering support; cost engineering; planning and scheduling; safety; quality assurance and control; field purchasing and general foremen. The costs are calculated based on an estimated project schedule. The construction manager's duration on the project includes one month in advance of beginning field operations and one month to close out the project, for a total of two additional months beyond the normal construction duration.

TEMPORARY FACILITIES AND UTILITIES

This section of the cost estimate includes the elements needed in order to support the construction management staff and construction of the project. Items that are normally included in this section are site trailers, clean-up of trailer area, water, sanitary facilities, field office supplies, site security, fire protection, medical supplies, temporary electrical power distribution system, telephones, copy machines and computer hardware and software.

CONSTRUCTION EQUIPMENT AND OPERATORS

This section of the cost estimate includes the construction equipment and operating engineers required in order to construct the mechanical and electrical portion of the project. Civil construction equipment and operating engineer costs are included in this section. In addition to the construction equipment and operating engineer cost, this section includes the cost of a master mechanic, teamsters, maintenance engineers, fuel, oil and grease, small tools, consumables, and scaffolding.

INDIRECT CONSTRUCTION SERVICES AND SUPPORT

This section of the cost estimate includes a detailed listing of the services needed in order to support the construction management staff and field forces. Items contained in this section of the cost estimate include continuous and final site clean-up, rubbish removal, safety equipment and supplies, various testing including soils and concrete, survey costs, weather protection, dust control, snow removal, piping radiography and other testing, testing of the grounding system and mechanical, electrical and I&C journeymen support during start-up.

INSURANCE/ TAXES/PERMITS/OTHER

This section of the cost estimate includes a detailed listing of a variety of components required in the cost estimate that are not appropriate for inclusion in other sections of the estimate. Items normally included here are freight costs for major equipment and bulk materials that are not included in the cost of the major equipment as supplied by the manufacturer or in the bulk material unit cost, travel costs, off-loading of major equipment and materials, heavy hauling of major equipment components not delivered directly to the site, general liability and umbrella insurance costs, start-up spare parts, permits, and payment and performance bonds. Payment and performance bonds for the EPC Contractor as well as any subcontractors are part of the EPC cost estimate.

A/E ENGINEERING

A/E Engineering costs were calculated based on current information contained in the EPC cost estimate model used for this project and modified as required to support each of the four candidate technologies.

START-UP AND TESTING

The costs associated with the start-up and testing of the facility are included in the EPC cost estimates developed for this program. Journeyman stand-by time for mechanical, electrical and instrumentation and control support is included in the EPC cost estimate.

EPC CONTRACTOR CONTINGENCY

The MM EPC cost estimates include the anticipated contingency that will be applied by the EPC contractor based on the conceptual level of the information that is normally available at the time a request for proposal is issued for an EPC contractor's proposal. The contingency percentages used in the cost estimates by MM were based on our past experience of proposing on firm lump sum projects at the conceptual stage where detailed engineering is not available.

EPC CONTRACTOR PROFIT

MM evaluated current profit margins of constructors of a suitable size that could adequately perform on a project of this size. MM used 10% for profit and 5% for contractor overhead for the civil, mechanical and electrical and I&C subcontractors for a total of 15% to cover these costs. MM also used a 7% mark-up on the total value of the project for the EPC contractor. It was assumed that, as is typically the case today, the EPC contractor would subcontract all civil, mechanical and electrical and I&C work and function as the general contractor. Therefore, in addition to the 15% mark-up for all of the subcontractors, the EPC contractor includes a 7% mark-up on top of the all the subcontractors as his fee for monitoring their work under the total EPC contract.

4. OWNER'S COSTS

OWNER'S PROJECT COSTS

These costs typically include the owner's cost for all the services required in order to obtain all approvals to construct the project including, but not limited to, legal costs, insurance costs, front-end engineering costs, the cost of land, project development and permitting costs. Also, included in this section would be the owner's construction management costs as well as the costs associated with the support of an owner's engineer. Since the cost estimates are based on the scope of an EPC contract only, these costs were excluded from the cost estimates

INTEREST DURING CONSTRUCTION

This section of the cost estimates would normally include costs for interest charges for money borrowed by the owner. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

PLANT SPARE PARTS

This section of the cost estimates would normally include costs for operating plant spare parts that an owner would stock to minimize plant downtime should a problem arise. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

FURNISHINGS

This section of the cost estimates would normally include costs for plant furnishings that the owner would need for the staff that would be operating the plant. Items normally included in this section would be desks, chairs, tables, lunch room equipment, window shades, computers, etc. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

OWNER'S ESCALATION

Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

OWNER'S CONTINGENCY

An owner's contingency of approximately 5% was included in the cost estimate.

ANY OTHER OWNER'S RELATED COSTS

Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

D. CONE TECHNICAL SPECIFICATIONS AND COSTS

1. 7HA.02 Simple Cycle Frame Combustion Turbine

The GE 7HA.02 is a large frame machine representing the current state-of-the-art regarding materials and combustion technology, giving it the highest efficiency available in the simple cycle technology market. In addition to a low minimum load point and high ramp rates that provide for flexible operation, the plant has relatively low capital costs. The 7HA.02 is in the process of entering commercial operation in a variety of locations throughout the country, including the Canal 3 facility in Southeastern Massachusetts ("SEMA"), which is scheduled to come online in 2019.

The capacity of the 7HA.02 in the simple cycle configuration is assumed to be 338 MW.[6] Based on current market trends, it is assumed to be equipped with evaporative coolers for power

[6] All capacity values are stated on a net basis.

augmentation as well as a fin fan cooling system. The plant utilizes SCR to control emissions and a carbon monoxide ("CO") catalyst. The heat rate of the facility is 9,220 Btu/kWh. Based on a typical configuration, the facility is assumed to be installed on a plot of 8.1 acres.

A summary of the technical specifications is shown in Table 10 below.

Table 10: GE 7HA.02 Simple Cycle Technical Specifications

Turbine Model	7HA.02
Configuration	Simple cycle frame machine
Net plant capacity (MW)	338
Location	Bristol County, Massachusetts
Cooling system	Fin fan coolers
Power augmentation	Evaporative coolers
Net heat rate (Btu/kWh)	9,220
Environmental controls	Selective Catalytic Reduction
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection
Plot size (acres)	8.1

CAPITAL COSTS

The capital costs for the simple cycle frame combustion turbine were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 11 below.

Table 11: GE 7HA.02 Simple Cycle Capital Costs

COST COMPONENT	7HA.02 SIMPLE CYCLE
EPC Costs	
Total Civil/Structural and Architectural Costs	$ 16,899,000
Total Mechanical Costs	132,754,000
Total Electrical Instrumentation and Controls Costs	27,482,000
Total Major Equipment and Construction Costs	*177,135,000*
Total Construction Management	3,866,000
Total Other Project Costs: Freight, Start-up Spares, A/E Support Start-up Testing	10,930,000
Subtotal Project Cost	**191,931,000**
Project Contingency – 5% on Major Equipment and 7% on Balance	10,899,000
Subtotal Project Cost with Contingency	**202,830,000**
EPC Contractor Fee	14,198,000
Owner Project Cost	**217,028,000**
Owner's Contingency	10,851,000
TOTAL EPC COST	**227,879,000**
Non-EPC Costs	
Electrical Interconnection Costs	27,000,000
Gas Interconnection Costs	2,000,000
Fuel Inventories	4,200,000
Working Capital	2,320,000
TOTAL NON-EPC COST	**35,520,000**
TOTAL OVERNIGHT CAPITAL COST	**$ 263,399,000**
Installed Capacity	338
$/kW	$ 779

OPERATING AND MAINTENANCE COSTS

Fixed costs for the facility consist of fixed O&M costs inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section 3.E. A long-term service agreement ("LTSA") was assumed that was inclusive of parts, labor, and materials for work done up to and including the first major outage. This was assumed to be a fixed price payment structure with monthly installments. Outage frequency and durations would be agreed to, but degradation generally is not guaranteed. Planned outages would be included under the agreement, but unplanned outages would not be covered.

Fixed costs for the GE 7HA.02 simple cycle frame combustion turbine are shown in Table 12.

Table 12: 7HA.02 Simple Cycle Operating Costs

Fixed Expense	Estimated cost (2021$)
Fixed O&M	$38.52/kW-year
Site leasing	$25,000/acre/year
Property taxes	3.0%
Insurance	0.6% of installed costs per year

In addition, variable O&M ("VOM") is assumed to be $4.50/MWh based on consultation with MM.

2. LM6000PF+ Aeroderivative Gas Turbine

The LM6000PF+ is one of the most widely installed plants in New England and is in widespread commercial use around the world. The unit, which is based on GE jet engine technology, is highly modular and can be engineered, procured, constructed, and entered into operation more quickly than any alternative technology operating above 20 MW. While the LM6000PF+ can be utilized in a combined cycle configuration, the simple cycle configuration is more common and was thus selected for review and analysis.

The capacity of the LM6000PF+ was assumed to be 94 MW. Based on current market trends, this unit was assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system. In addition, it was assumed that the plant would utilize SCR to control emissions. The heat rate of the facility was assumed to be 9,774 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 4.5 acres.

A summary of the technical specifications is shown in Table 13 below.

Table 13: LM6000PF+ Technical Specifications

Turbine Model	LM6000PF+
Configuration	Two SC Aeroderivative GTs
Net plant capacity (MW)	94
Location	Bristol County, Massachusetts
Cooling system	Fin fan coolers
Power augmentation	Evaporative coolers
Net heat rate (Btu/kWh)	9,774
Environmental controls	Selective Catalytic Reduction
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection
Plot size (acres)	4.5

CAPITAL COSTS

The capital costs for the LM6000PF+ were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 14.

Table 14: LM6000PF+ Capital Costs

COST COMPONENT	LM6000 PF+
EPC Costs	
Total Civil/Structural and Architectural Costs	$ 11,696,000
Total Mechanical Costs	78,377,000
Total Electrical Instrumentation and Controls Costs	17,132,000
Total Major Equipment and Construction Costs	*107, 205,000*
Total Construction Management	3,392,000
Total Other Project Costs: Freight, Start-up Spares, A/E Support Start-up Testing	8,230,000
Subtotal Project Cost	**118,827,000**
Project Contingency – 5% on Major Equipment and 7% on Balance	6,988,000
Subtotal Project Cost with Contingency	**125,815,000**
EPC Contractor Fee	8,807,000
Grand Total Project Cost	134,622,000
Owner's Contingency	6,731,000
Owner Project Cost	**141,353,000**
Non-EPC Costs	
Electrical Interconnection Costs	27,000,000
Gas Interconnection Costs	2,000,000
Fuel Inventories	900,000
Working Capital	1.400,000
TOTAL NON-EPC COST	**31,300,000**
TOTAL OVERNIGHT CAPITAL COST	**$ 172,653,000**
Installed Capacity	94
$/kW	$ 1837

OPERATING AND MAINTENANCE COSTS

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section 3.E. An LTSA was assumed, including parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service. The removed rotor would then be serviced and used in the shared rotor program with other plant owners. This minimizes down time for the aeroderivative plants. The duration of the LTSA would be up to and including the first major outage. Planned outages would be included under the agreement, but unplanned outages would not be covered. Fixed costs for the LM6000 are shown in Table 15 below.

Table 15: LM6000PF+ Fixed Operating Costs

Fixed Expense	Estimated cost (2021$)
Fixed O&M	$83.52/kW-year
Site leasing	$25,000/acre/year
Property taxes	3.0%
Insurance	0.6% of installed costs per year

VOM is assumed to be $5.00/MWh based on consultation with MM.

3. LMS100PA Advanced Aeroderivative

The LMS100PA is a relatively new design from GE. While not in widespread use, the unit's efficiency and relatively low capital cost make it an attractive option for developers and a candidate for selection as the reference unit. The LMS100PA is a "hybrid" design in that it incorporates both frame and aeroderivative turbine technologies to create a unit that is highly efficient and highly flexible.

The LMS100PA is assumed to be installed in a simple cycle configuration. Because of the high efficiency of the turbine, exhaust gases are relatively cold, making the addition of a heat-recovery steam generator uneconomical. As a result, there is no expectation of commercialization of an LMS100 in a combined cycle configuration in New England for the foreseeable future.

The capacity of the LMS100PA was assumed to be 103 MW. Based on current market trends, it was assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system and an SCR to control emissions. The heat rate of the facility was assumed to be 9,021 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 5.7 acres.

A summary of the technical specifications is shown in Table 16 below.

Table 16: LMS100PA Technical Specifications

Turbine Model	LMS100PA
Configuration	SC Advanced Aeroderivative
Net plant capacity (MW)	103
Location	Bristol County, Massachusetts
Cooling system	Evaporative coolers
Power augmentation	Evaporative coolers
Net heat rate (Btu/kWh)	9,021
Environmental controls	Selective Catalytic Reduction
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection
Plot size (acres)	5.7

CAPITAL COSTS

The capital costs for the LMS100PA were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 17 below.

Table 17: LMS100PA Capital Costs

COST COMPONENT	LMS100PA
EPC Costs	
Total Civil/Structural and Architectural Costs	$ 10,792,000
Total Mechanical Costs	64,857,000
Total Electrical Instrumentation and Controls Costs	14,929,000
Total Major Equipment and Construction Costs	*90,578,000*
Total Construction Management	3,392,000
Total Other Project Costs: Freight, Start-up Spares, A/E Support Start-up Testing	7,645,000
Subtotal Project Cost	**101,615,000**
Project Contingency – 5% on Major Equipment and 7% on Balance	6,006,000
Subtotal Project Cost with Contingency	**107,621,000**
EPC Contractor Fee	7,533,000
Grand Total Project Cost	115,154,000
Owner's Contingency	5,758,000
Owner Project Cost	**120,912,000**
Non-EPC Costs	
Electrical Interconnection Costs	27,000,000
Gas Interconnection Costs	2,000,000
Fuel Inventories	900,000
Working Capital	1,270,000
TOTAL NON-EPC COST	**31,170,000**
TOTAL OVERNIGHT CAPITAL COST	**$ 152,082,000**
Installed Capacity	103
$/kW	$ 1,477

OPERATING AND MAINTENANCE COSTS

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section 3.E. An LTSA was assumed, inclusive of parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service. The removed rotor would then be serviced and used in the shared rotor program with other plant owners, which minimizes down time for the aeroderivative plants. The duration of the LTSA would be up to and including the first major outage. Planned outages would be included under the agreement, but unplanned outages would not be covered.

Fixed costs for the LMS100PA are shown in Table 18 below.

Table 18: LMS100PA Fixed Operating Costs

Fixed Expense	Estimated Cost (2021$)
Fixed O&M	$69.00/kW-year
Site leasing	$25,000/acre/year
Property taxes	3.0%
Insurance	0.6% of installed costs per year

VOM is assumed to be $5.00/MWh based on consultation with MM.

4. 7HA.02 Combined Cycle Combustion Turbine

The combined cycle combustion turbine utilizes the same machine as the simple cycle machine. However, with the combined cycle combustion turbine, a HRSG is added to allow for additional generation using exhaust gases. Adding the HRSG increases capital costs significantly; however, doing so also increases plant size and plant efficiency.

The combined cycle combustion turbine was assumed to have duct firing capability. Duct firing is an option many plant developers choose to provide a highly flexible source of short-notice capacity that can be used to capture revenues during periods of high prices. Because inclusion of duct firing capability appears to be the current prevailing trend among developers, it has been included for purposes of this analysis.

The combined cycle combustion turbine is assumed to have a baseload capacity of 491 MW and a total capacity of 533 MW when duct firing is engaged. It is assumed to be equipped with both fin fan cooling and evaporative coolers for power augmentation. To control emissions, the plan utilizes both SCR and a CO catalyst. The baseload heat rate of the CC was assumed to be 6,381 Btu/kWh; when duct firing is engaged, the net heat rate increases to 6,546 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 15 acres.

A summary of the technical specifications is shown in Table 19 below.

Table 19: GE7HA.02 Combined Cycle Technical Specifications

Turbine model	7HA.02 Combined Cycle
Configuration	Combined Cycle w/ Frame GT
Net baseload capacity (MW)	491
Net capacity w/ duct firing (MW)	533
Location	Bristol County, Massachusetts
Cooling system	Fin fan coolers
Power augmentation	Evaporative coolers
Baseload net heat rate (Btu/kWh)	6,381
Duct firing net heat rate (Btu/kWh)	6,546
Environmental controls	SCR and CO catalyst
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection
Plot size (acres)	15

CAPITAL COSTS

The capital costs for the GE 7HA.02 combined cycle combustion turbine were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 20 below.

Table 20: GE7HA.02 Combined Cycle Capital Costs

COST COMPONENT		7HA.02 COMBINED CYCLE
EPC Costs		
Total Civil/Structural and Architectural Costs	$	49,885,000
Total Mechanical Costs		253,998,000
Total Electrical Instrumentation and Controls Costs		58,309,000
Total Major Equipment and Construction Costs		*362,192,000*
Total Construction Management		12.531,000
Total Other Project Costs: Freight, Start-up Spares, A/E Support Start-up Testing		26,507,000
Subtotal Project Cost		**401,230,000**
Project Contingency – 5% on Major Equipment and 7% on Balance		23,780,000
Subtotal Project Cost with Contingency		**425,010,000**
EPC Contractor Fee		29,751,000
Grand Total Project Cost		454,761,000
Owner's Contingency		22,738,000
Owner Project Cost		**477,499,000**
Non-EPC Costs		
Electrical Interconnection Costs		27,000,000
Gas Interconnection Costs		2,000,000
Fuel Inventories		4,200,000
Working Capital		7,000,000
TOTAL NON-EPC COST		**40,200,000**
TOTAL OVERNIGHT CAPITAL COST	**$**	**517,699,000**
Installed Capacity		533
$/kW	$	971

OPERATING AND MAINTENANCE COSTS

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section 3.E.

Fixed costs are shown in Table 21 below.

Table 21: GE7HA.02 Combined Cycle Fixed Operating Costs

Fixed Expense	Estimated Cost (2021$)
Fixed O&M	$60.12/kW-year
Site leasing	$25,000/acre/year
Property taxes	3.0%
Insurance	0.6% of installed costs per year

VOM is assumed to be $3.50/MWh based on consultation with MM.

5. Escalation to 2021 Costs

We escalated capital costs from 2016$ to the beginning of each unit's construction period using estimates from the Bureau of Labor Statistics' ("BLS") Producer Price Indices ("PPI"). We used a 10-year average annual percent change from two BLS PPI indices for different capital cost components.[7]

We escalated fuel costs for the gas turbines using NY Harbor ultra-low-sulfur-diesel ("ULSD") futures settlements.[8] Our estimate is based on a three-year forward average annual percent change of ULSD futures prices at NY Harbor.

E. FINANCIAL ASSUMPTIONS

1. Financial Inputs

The estimate of CONE/Net CONE is based on the revenue required, net of cash flows from market revenues, by a new entrant to recover its capital and operating costs over a 20-year period. This estimate is inclusive of the cost of providing a return to equity investors and debt holders and is based on the reasonable assumption that significant amounts of capital will only be invested if investors anticipate that their investment will generate returns in excess of their cost of capital. Consistent with previous estimates, the CONE/Net CONE value is expressed on a real, levelized basis. That is, the calculation produces a first year payment such that if the capacity payment increases by inflation every year over the twenty-year period, the NPV of a unit's costs are equal to the NPV of its revenues over the 20-year period.

It is customary to discount uncertain future cash flows at an after-tax weighted average cost of capital. The appropriate discount rate should reflect systemic financial market risks and project-specific risks of a merchant developer participating in the New England wholesale markets and the return required by investors to compensate for those risks. We recognize that generation projects can be financed under a project financing or balance sheet financing approach. Project financing uses project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a power plant. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual power plant. Balance sheet financing employs debt backed by the project owner itself, which may have significant, diverse resources and assets beyond the individual power plant. While some plants in New England are financed on a "stand-alone" or project-specific basis, the specifics of these financing structures are not publicly available, and are diverse and difficult to represent. Because publicly available data about project-specific financing is not available, we chose a peer group of publicly traded independent power producers ("IPPs") and used their financial parameters to inform our calculation of the recommended cost of capital. We then made reasonable adjustments to this proxy group data to calculate an after-tax weighted average cost of capital to reflect how a generic new entrant would likely view the risk of merchant development in New England.

[7] BLS PPI WPU1197; BLS PPI WPUID612: not seasonally adjusted, annual average percent change 2006-2015.
[8] ULSD Forward Curve as of September 7, 2016; CME Group.

Our financing paradigm assumes a reasonable balance between project-specific financing and large corporate balance sheet financing. This paradigm also assumes a parent company will find value in any operating income losses experienced over the life of the facility. Since there is no universally agreed upon convention for modeling tax effects for the purposes of a Net CONE calculation, we believe this assumption is reasonable.

The cost of capital is calculated as the weighted average of the required return for equity holders and cost of debt. In addition to the cost of capital, the key financial inputs to the calculation of CONE/Net CONE include inflation, depreciation, and property taxes. Derivation of each input is described below.

INFLATION

CONE/Net CONE, and the inputs to calculate CONE/Net CONE are expressed in real (constant) dollars. Inflation is a key factor used to translate projected nominal cost and revenue streams to constant, or real, terms. It is also used in the calculation of a real discount rate, the levelization factor for CONE/Net CONE.

Two estimates of inflation were reviewed to develop the annual inflation outlook of 2%. The Blue Chip Long Term Consensus Forecast provides the most forward looking forecast of inflation.[9] The ten-year average consensus forecast of CPI for all urban consumers is estimated at 2.3% (2018-2027).

Second, we reviewed spreads between yields on Treasury Inflation-Protected Securities ("TIPS") and conventional U.S. Treasuries. TIPS provide holders a return on their investment that is indexed to CPI to protect holders from inflation risk. Conventional Treasuries do not. As such, the difference in the yields between bonds of each type with the same maturity date, calculated as the conventional yield minus the TIPS yield, reflects the market's expectation of inflation for the period leading up to the maturity date. A 30-day average of daily yield curves published by the U.S. Treasury at the time of our analysis indicated that the spread in the yields for bonds of each type with 20-year maturities averaged 1.37% over that period.[10]

Based on these inputs, we assumed an average long-term annual inflation rate of 2.0% for all CONE and ORTP calculations.

DEPRECIATION

We used a 15 or 20-year tax life according to IRS guidelines using the Modified Accelerated Cost Recovery System ("MACRS") to depreciate the eligible portion of total installed costs over the forecast period.[11] The federal tax code allows recovery over 15 years for a combustion turbine and over 20 years for a combined cycle resource.

To calculate the annual value of depreciation, the "depreciable costs" for a new resource are the sum of the depreciable capital costs and the accumulated interest during construction ("IDC"). Several capital cost line items are considered non-depreciable, including fuel inventories and working capital, and are not included in total depreciable costs. IDC is calculated based on the assumption that

9 Blue Chip Economic Indicators, Vol. 41, No. 3, March 2016.
10 June 10, 2016 – July 22, 2016.
11 Table B-2, IRS Publication 946. Half-Year Convention.

capital structure during the construction period is the same as the overall project, i.e., 60% debt and 7.75% COD.

PROPERTY TAXES

Property taxes are based on municipal tax rates, which are generally differentiated by business type. A review of Commercial and Industrial ("C&I") rates in Massachusetts over the last three years indicated an average rate of 0.2%-4.0% by municipality.

The assumed property tax rate is based on a review of C&I rates in the reference county's four major cities (Bristol County, Massachusetts) over the period 2013-2015. Based on the data shown in Table 22, a property tax rate of 3.0% was assumed.

Table 22: Municipal Tax Rates for Selected Cities in SEMA[12]

	Attleboro	Fall River	Taunton	New Bedford
2013	2.05%	2.54%	3.06%	2.95%
2014	2.16%	2.67%	3.12%	3.11%
2015	2.13%	2.81%	3.32%	3.36%

This 3% rate was applied to an average of net plant values (gross plant less accumulated depreciation) on an annual basis. This assumption was based on the fact that resources subject to property taxes will have property tax expenses in each year of operation that will not vary significantly.

INCOME TAX RATES

We calculated income tax rates based on current federal and state tax rates. The marginal federal income tax rate is 35%.[13] The state income tax rate for Massachusetts is 8.0%.[14] The effective income tax rate is calculated to be 40.2%.[15]

COST OF CAPITAL

The Weighted Average Cost of Capital ("WACC") for an investment represents the blend of rates paid on equity and debt specific to that investment's capital structure and can be expressed by the following equation:

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12 Massachusetts Department of Revenue, 2016, https://dlsgateway.dor.state.ma.us/gateway/Public/WebForms/TaxRate/ReportTRApprovalPublic.aspx.

13 Internal Revenue Service, 2015 Instructions for Form 1120, U.S. Corporation Income Tax Return. January 21, 2016. Available at http://www.irs.gov/pub/irs-pdf/i1120.pdf.

14 Massachusetts Department of Revenue, 2016. Available at: http://www.mass.gov/dor/businesses/current-tax-info/guide-to-employer-tax-obligations/business-income-taxes/corporations/corporate-excise-tax.html.

15 Massachusetts assumed as the reference location for all technologies except onshore wind. Therefore, a state income tax rate of 8% is assumed for all CONE and ORTP calculations except that of onshore wind, for which a state tax rate of 8.5% is assumed (New Hampshire).

WACC = ROE * Weight of Equity + COD * Weight of Debt

Where:

ROE = Return on Equity, and
COD = Cost of Debt

Derivation of each input to the WACC calculation is described below and is based on a peer group of merchant generation companies who may be likely to develop projects in New England. Our initial peer group consisted of the following public traded companies:

- AES Corporation
- Calpine Corporation
- Dynegy Inc.
- NRG Energy, Inc.
- Talen Energy Inc.

We received feedback from stakeholders that the full group of peers does not appropriately represent merchant entry in New England because many hold diverse portfolios with some portion of regulated assets. Specifically, stakeholders expressed concerns about AES' portfolio, and that Talen's merger-related activity may skew the results of our analysis. We considered these comments in evaluating the components of cost of capital, as well as the overall cost of capital chosen for the evaluation of CONE and Net CONE; each component is discussed in more detail below.

RETURN ON EQUITY

Return on equity ("ROE") is the amount of return that would be required by investors to compensate for the risk of making an equity investment in a merchant generation plant. The risk environment determines the hurdle rates for investment. Equity raised for uncontracted, merchant projects requires a higher return to investors than equity raised for contracted projects. For energy and capacity that is fully contracted, the cost of equity reflects a lower level of risk, assuming a significant degree of leverage. For uncontracted merchant capacity, developers target a higher after-tax return on equity based on the perceived high risks of cost recovery in the market. A return on equity of 13.4% represents an appropriate return under equilibrium market risk conditions.

To calculate the appropriate return on equity for this analysis, the Capital Asset Pricing Model ("CAPM") was used. CAPM is a common analytical approach in financial modeling, and assumes that equity investors base their required returns on a risk-free rate of return, the rate at which they would be compensated for an available investment that carried no risk, plus compensation for the relative risk of a specific security in relation to the broader market. CAPM is expressed by the following equation:

$$R_e = R_f + \beta\,(R_m - R_f)$$

Where:

R_e= Required return on equity

R_f = The risk-free rate

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific security, and

R_m = The return required of the market as a whole

We reviewed several estimates of a risk-free rate, including the 30-day average of the 30-year Treasury yield curve, as well as estimates from Blue Chip. In addition, we reviewed beta estimates from several sources including Yahoo Finance, Bloomberg, and Value Line. Based on our assumed capital structure of 60/40 (D/E), we re-levered our estimates of beta for inclusion in our CAPM calculation.

Table 23 shows beta estimates that reflect each individual IPP's historical capital structure ("levered beta"). Using the historical average capital structure, or debt to equity ratio ("D/E Ratio"), we calculate an unlevered beta which reflects the beta of each IPP without any debt. We then re-lever the beta ("Re-levered Beta") using our assumed capital structure of 40/60 equity to debt.

Table 23: Peer Group Beta Estimates

Beta Estimates				
Bloomberg[16]	**(2-year Beta)**			
	Levered Beta	**D/E ratio**	**Unlevered Beta**	**Re-levered beta**
AES	1.07	2.28	0.45	0.86
CPN	1.17	1.65	0.59	1.12
DYN	1.28	1.60	0.65	1.24
NRG	1.17	2.61	0.46	0.87
TLN[17]	1.32	2.30	0.55	1.05
Value Line[18]	**(5-year Beta)**			
	Levered Beta	**D/E ratio**	**Unlevered Beta**	**Re-levered beta**
AES	1.15	2.28	0.49	0.92
CPN	1.00	1.65	0.50	0.95
DYN	1.45	1.60	0.74	1.41
NRG	1.10	2.61	0.43	0.81
TLN	NA	2.30	NA	NA

We reviewed two estimates of the overall market return: a historical estimate from Ibbotson; and a forward-looking estimate of the S&P 500 Index. The following table shows the calculations for a number of historic and forward looking estimates of ROE.

16 Bloomberg as of September 2016.

17 We received feedback from stakeholders that the CAPM analysis for Talen should use a pre-merger beta estimate. Talen's beta as of June 1, 2016, or pre-merger announcement, was 1.39 according to Bloomberg. This beta estimate for Talen does not change our ROE recommendation of 13.4%.

18 Value Line as of June, September 2016.

Table 24: CAPM Analysis

CAPM	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	
		Beta- Relevered			Market Return			Market Risk Premium		ROE based on…		
	Risk-Free Rate	Value Line				Income return				Historical	Projected	
			Bloomberg	Average	Historical	Gov. Bonds	Projected	Historical	Projected	MRP	MRP	
	Treasury 30-year											
AES	2.24%	0.92	0.86	0.89	12.10%	5.10%	12.85%	7.00%	10.61%	8.46%	11.67%	
CPN	2.24%	0.95	1.12	1.03	12.10%	5.10%	12.85%	7.00%	10.61%	9.48%	13.22%	
DYN	2.24%	1.41	1.24	1.32	12.10%	5.10%	12.85%	7.00%	10.61%	11.50%	16.28%	
NRG	2.24%	0.81	0.87	0.84	12.10%	5.10%	12.85%	7.00%	10.61%	8.13%	11.16%	
TLN	2.24%	NA	1.05	1.05	12.10%	5.10%	12.85%	7.00%	10.61%	9.62%	13.43%	
									All	9.44%	13.15	11.29%
	BCFF 10-year											
AES	3.80%	0.92	0.86	0.89	12.10%	5.10%	12.85%	7.00%	9.05%	10.02%	11.85%	
CPN	3.80%	0.95	1.12	1.03	12.10%	5.10%	12.85%	7.00%	9.05%	11.04%	13.17%	
DYN	3.80%	1.41	1.24	1.32	12.10%	5.10%	12.85%	7.00%	9.05%	13.06%	15.78%	
NRG	3.80%	0.81	0.87	0.84	12.10%	5.10%	12.85%	7.00%	9.05%	9.69%	11.41%	
TLN	3.80%	NA	1.05	1.05	12.10%	5.10%	12.85%	7.00%	9.05%	11.18%	13.34%	
									All	11.00%	13.11%	12.05%
	BCFF 30-year											
AES	4.30%	0.92	0.86	0.89	12.10%	5.10%	12.85%	7.00%	8.55%	10.52%	11.90%	
CPN	4.30%	0.95	1.12	1.03`	12.10%	5.10%	12.85%	7.00%	8.55%	11.54%	13.15%	
DYN	4.30%	1.41	1.24	1.32	12.10%	5.10%	12.85%	7.00%	8.55%	13.56%	15.61%	
NRG	4.30%	0.81	0.87	0.84	12.10%	5.10%	12.85%	7.00%	8.55%	10.19%	11.49%	
TLN	4.30%	NA	1.05	1.05	12.10%	5.10%	12.85%	7.00%	8.55%	11.68%	13.31%	
									All	11.50%	13.09%	12.30%
Notes:							**All**			**10.64%**	**13.12%**	**11.88%**
[1] Blue Chip Financial Forecast - Vol. 35, No. 6, June 1, 2016												
[2] Source: Value Line												
[3] Source: Bloomberg Professional												
[4] Equals average ([2], [3])												
[5] Source: 2015 Ibbotson SBBI Valuation Yearbook, Table 6-7, pg 91												
[6] Source: 2015 Ibbotson SBBI Valuation Yearbook, Table 6-7, pg 91												
[7] Source: Bloomberg Professional												
[8] Equals [5] [6]												
[9] Equals [7] [1]												
[10] Equals [1] + [4] x [8]												
[11] Equals [1] + [4] x [9]												

We also reviewed these results in light of stakeholder feedback about the appropriate peer group.

Table 25: Summary of CAPM Results by Alternative Peer Group

			ROE based on…		
			Historical	**Projected**	
Risk-free Rate			MRP	MRP	Average
Treasury 30-yr		All	9.44%	13.15%	11.29%
		CPN, DYN, NRG, TLN	9.68%	13.52%	**11.60%**
		CPN, DYN, NRG	9.70%	13.55%	**11.63%**
BCFF 10-yr		All	11.00%	13.11%	12.05%
		CPN, DYN, NRG, TLN	11.24%	13.42%	**12.33%**
		CPN, DYN, NRG	11.26%	13.45%	**12.36%**
BCFF 30-yr		All	11.50%	13.09%	12.30%
		CPN, DYN, NRG, TLN	11.74%	13.39%	**12.57%**
		CPN, DYN, NRG	11.76%	13.42%	**12.59%**
Average		All	10.64%	13.12%	11.88%
		CPN, DYN, NRG, TLN	10.89%	13.45%	**12.17%**
		CPN, DYN, NRG	10.91%	13.47%	**12.19%**

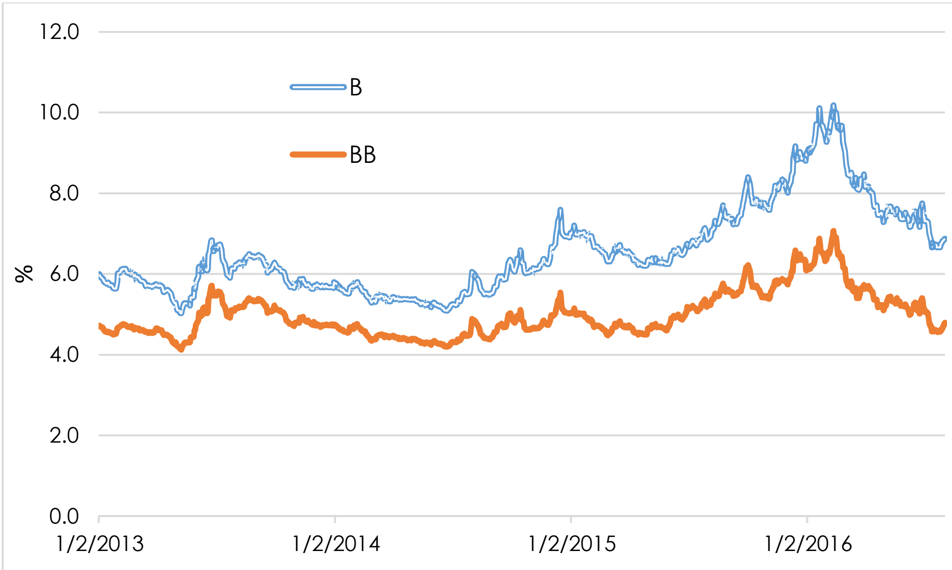
As shown in Table 25, forward looking estimates for different combinations of peer companies range from 13.09 to 13.55%. Given stakeholder concerns about appropriate peer comparators, we have determined that an ROE of 13.4% towards the upper end of the range of results is appropriate for the CONE/Net CONE calculation.

COST OF DEBT

To estimate Cost of Debt ("COD"), we reviewed credit ratings of companies active in the development and commercialization of merchant generation. Of the five original comparators, each has below investment-grade senior unsecured debt ratings ranging from "B" to "BB". Ratings are estimated by Standard & Poor's and reported by SNL.[19] We then reviewed historical generic corporate bond yields for B and BB rated companies. Over the period, January 1, 2016 through August 1, 2016, bond yields for companies with a B rating averaged 8.12%, while yields for companies with a BB rating averaged 5.59%.

[19] SNL Financial.

Figure 1: Generic Corporate Bond Yields[20]



A longer-term view of generic corporate debt reveals these averages have been steadily increasing in recent years, with levels peaking in early 2016, as shown in Figure 1. Longer term average costs of debt are lower than recent averages, at 6.57% for a B rating for the period 2013-2016. Given these trends, and that our peer group credit ratings lie between a BB and B rating, we have assumed a cost of debt of 7.75%. This assessment is at the upper end of the range, and is consistent with the increased risk associated with a merchant generating plant operating without a contract.

CAPITAL STRUCTURE

Capital structure is the ratio of debt to equity used to finance an investment. The appropriate capital structure for a merchant development project can take many forms depending on its financing.

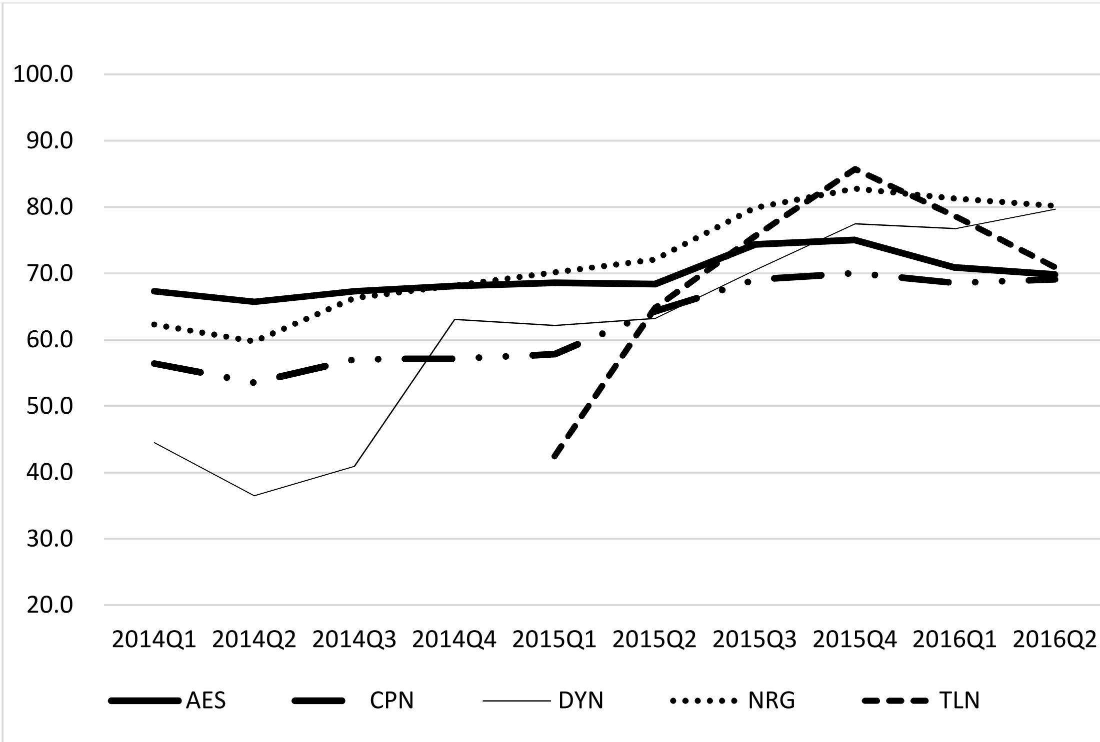
To derive an appropriate capital structure for the Net CONE calculation, we reviewed the capital structures of the aforementioned peer group of companies who would be likely to make such an investment. Since each company in the peer group is public, their debt weight, the total market value of the debt outstanding as a percentage of the market value of their total capital (debt plus equity) is available via their filings with the Securities Exchange Commission ("SEC"). We reviewed this data as reported by Bloomberg.

Debt weights for each member of the peer group are shown in Figure 2 below.[21]

[20] BofA Merrill Lynch, BofA Merrill Lynch US High Yield B and BB Effective Yield©, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/BAMLH0A2HYB[B]EY.

[21] Debt weights for Talen are unavailable prior to the company's founding in the first quarter of 2015.

Figure 2: Peer Group Debt Weights[22]



Over the 2015-2016 period, the average capital structure contained a mix of 67% debt and 33% equity.[23] More recently, for the first two quarters of 2016 this average amounts to 75% debt and 25% equity, as shown in Table 26.[24]

[22] Source: Bloomberg, LP.
[23] Bloomberg. Six quarters of data was evaluated for Talen.
[24] For the limited peer group (CPN, DYN, NRG) the 10 quarter average is 65% debt, and the two quarter average is 76% debt.

Table 26: Total Debt/Total Capitalization[25]

Total Debt/ Total Capitalization (%)												
Company	**2016Q2**	**2016Q1**	**2015Q4**	**2015Q3**	**2015Q2**	**2015Q1**	**2014Q4**	**2014Q3**	**2014Q2**	**2014Q1**		**Average**
AES	69.8	70.9	75.0	74.3	68.4	68.6	68.1	67.3	65.7	67.3		69.6
CPN	69.1	68.6	70.1	69.1	64.3	57.8	57.2	57.1	53.5	56.5		62.3
DYN	79.7	76.7	77.5	70.5	63.2	62.1	63.1	41.0	36.5	44.5		61.5
NRG	80.2	81.3	82.8	79.9	72.1	70.2	68.2	66.3	59.7	62.3		72.3
TLN	70.9	78.7	85.7	75.6	64.8	42.5	NA	NA	NA	NA		69.7
										Average		**67.1**

While the debt weight of the peer group has, on average, been higher over the last year, we assume this to be a short-duration trend driven by historically low market costs of debt which tend to encourage borrowing over the short term, and depressed equity values. As such, a capital structure more consistent with the longer historical period shown in Figure 2 was assumed. In order to reflect the increased risk of a merchant generator participating in the New England markets, we additionally adjusted the equity weighting upwards to 40% instead of today's average of 33%. Therefore, an overall capital structure of 60% debt and 40% equity assumes an increased level of return to equity holders.

2. WACC Calculation and ATWACC

By inputting the assumptions for ROE, COD, and capital structure described above into the WACC calculation yields a WACC of 10.0%, as shown below:

$$\text{WACC} = 13.4\% * 40\% + 7.75\% * 60\% = 10.0\%$$

We translated these components to a discount rate by reflecting the effect of taxes on the cost of debt to derive an after tax WACC of 8.1%. This rate was then adjusted for inflation to derive a "real ATWACC" of 6.0%.

3. Cost of Capital Comparison

The estimate of WACC described above, as well as each of the key inputs, is consistent with findings utilized in the 2013 Net CONE estimate, the most recent calculation of Net CONE conducted by PJM, and the Net CONE value recently recommended by NYISO Staff.[26,27,28] Those values are shown in Table 27.

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[25] Bloomberg Professional.
[26] FERC Docket ER14-1639-000, Testimony of Dr. Samuel A. Newell and Mr. Christopher Ungate of behalf of ISO-NE Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, April 1, 2014.
[27] Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, The Brattle Group and Sargent & Lundy, May 15, 2014.
[28] Study to Establish New York Electricity Market ICAP Demand Curve Parameters, Analysis Group Inc. and Lummus Consultants International, Inc. June 23, 2016.

Table 27: Cost of Capital Comparison

	ISO-NE (2013)	PJM (2013)	NYISO (2016)	ISO-NE (2015)
ROE	13.8%	13.8%	13.4%	13.4%
COD	7.00%	7.00%	7.75%	7.75%
Capital structure:				
Debt weight	60%	60%	55%	60%
Equity weight	40%	40%	45%	40%
WACC	9.7%	9.7%	10.3%	10.0%

F. REVENUE OFFSETS

1. Energy and Ancillary Services Revenues

OVERVIEW

The process to estimate the Energy and Ancillary Services ("E&AS") offset for each candidate reference technology consisted of three primary steps. First, in order to estimate energy revenues, a 20-year forecast of locational marginal prices ("LMPs") for the SEMA load zone was developed via simulation. Second, revenues earned from participation in wholesale markets were estimated based on a projection of Ancillary Service ("AS") payment rates, the LMP forecast, and the variable expenses and operating characteristics of each resource. Third, cash flows from the sale of energy and AS were levelized using the financial model described in Section E. Details regarding the calculation of the E&AS offset for the candidate reference units are provided below. Details of major assumptions are shown in Appendix A.

LMP FORECAST

LMPs were forecasted using AURORAxmp ("AURORA"), a chronological-dispatch simulation model widely used in the energy industry for price forecasting and market analysis. AURORA, which is licensed by EPIS, Inc., allows for the simulation of wholesale electric markets on an hourly basis on a highly granular level.[29] Using this tool, prices by load zone in New England were forecasted on an hourly basis for the period 2021-2040.

Key inputs to the LMP forecast included a forecast of delivered gas prices, a forecast of emission allowances for carbon dioxide ("CO_2"), a load forecast, a schedule of plant additions and retirements, and an outlook on the transmission grid serving New England and connecting New England to neighboring regions.

[29] See http://epis.com/aurora_xmp/ for more detail regarding AURORA.

GAS PRICE FORECAST

The gas price forecast was developed using GPCM, the industry-standard tool for long-term price forecasting and simulation of the natural gas markets. GPCM is licensed by RBAC, Inc. ("RBAC").[30] The forecast is based on RBAC's 2016Q2 Base Case, which was developed by RBAC and released in spring 2016. The only change made to the 2016Q2 Base Case was the exclusion of Spectra Energy Corporation's Access Northeast project. Access Northeast is a project supported by contracts with Massachusetts Electric Distribution Companies ("EDCs"), which were approved by the Massachusetts Department of Public Utilities ("MA DPU") in Docket 15-37. However, the Massachusetts Supreme Judicial Court found in an appellate decision in Docket SJC-12051 that such contracting by the EDCs was not allowable under Massachusetts law. As a result, it was determined that Access Northeast will likely not be completed, and the project was removed from the GPCM simulation.

Other project upgrades located in the Northeast U.S. and Canada that were included in the 2016Q2 Base Case and that were not adjusted are shown in Table 28.

Table 28: Selected Pipeline Expansion Projects Included in the 2016 Q2 RBAC Base Case

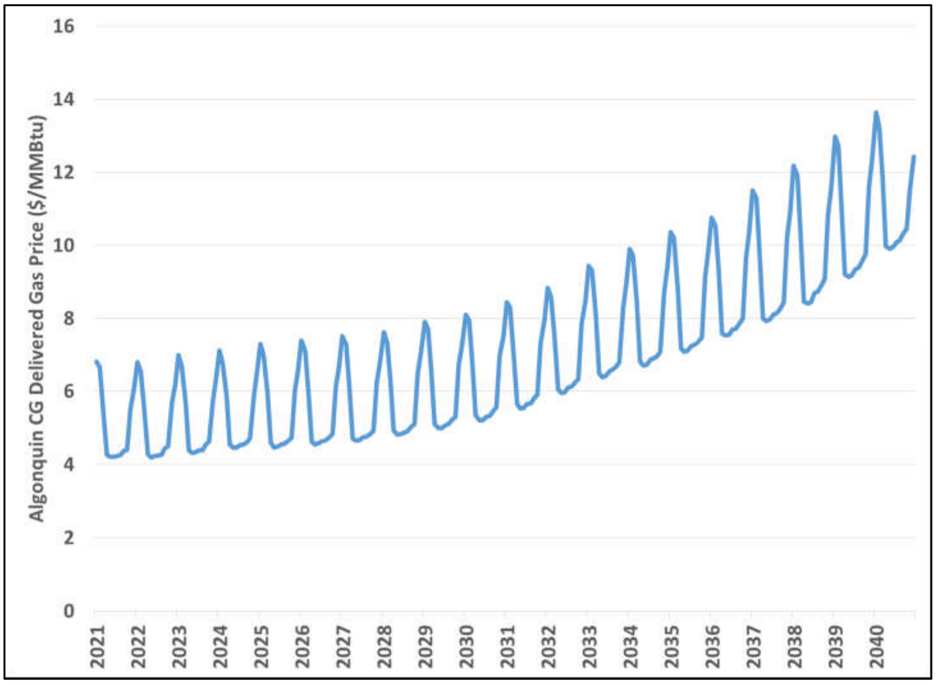
Pipeline	Project	Capacity (MMcf/d)
Algonquin Gas Transmission / Maritimes & Northeast	Atlantic Bridge	600
Algonquin Gas Transmission / Maritimes & Northeast	Salem Lateral	115
Algonquin Gas Transmission	Algonquin Incremental Markets	342
Constitution	New pipeline	650
Iroquois Gas Transmission System	South-to-North Project	650
Iroquois Gas Transmission System	Wright Interconnect Project	650
Portland Natural Gas Transmission System	Coast-to-coast	300
Tennessee Gas Pipeline	Connecticut Expansion	72
TransCanada	Eastern Mainline Expansion	1,203

All projects were assumed to enter service before the start of the forecast period in 2021.

The delivered price for the Algonquin Citygates ("Algonquin CG"), the pricing index most relevant to generators in SEMA, is shown in Figure 3 below.

30 See https://rbac.com/ for more detail regarding GPCM.

Figure 3: Algonquin CG Price Forecast



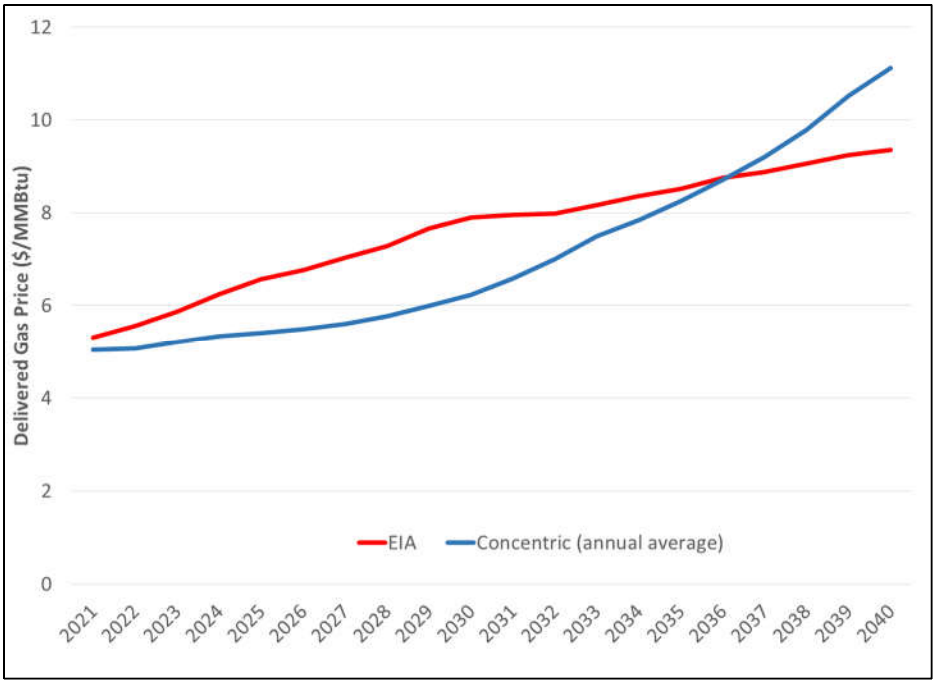
The forecast indicates gas prices growing at an average rate of approximately 4.3% per year on a nominal basis (approximately 2.2%, expressed on a real basis), with more rapid increases in prices observed in the second half of the forecast. Drivers behind rising prices beginning in the early 2030s include upward pressure on the cost of shale gas supply in the Appalachian producing regions, New England's primary source of gas supply since the late 2000's, and increasing levels of constraint on the pipelines serving the region as gas demand in New England continues to grow while no major new pipeline expansion projects are added during the forecast period.

Concentric has compared this forecast to other available indices in the public arena and has concluded that it is reasonable. One such comparison is shown in Figure 4, which compares the Algonquin CG forecast to the Energy Information Administration's ("EIA") forecast of delivered gas prices for electric power generators in New England, published in the 2016 Annual Energy Outlook.[31,32]

[31] See Table 3.1 of the 2016 AEO.

[32] For purposes of comparison, the EIA forecast, which is shown in real dollars, was escalated at an inflation rate of 2.0% consistent with the inflation input used elsewhere in this analysis, rather than by the escalation rate provided in the AEO.

Figure 4: Comparison of Gas Price Forecast to 2016 AEO[33]



Average prices in the two forecasts are within 10% of each other. The Concentric forecast averages \$5.20/MMBtu on a real (2016\$) basis for the forecast; the EIA outlook is approximately 8% higher, averaging \$5.65/MMBtu.

CO_2 ALLOWANCE PRICE FORECAST

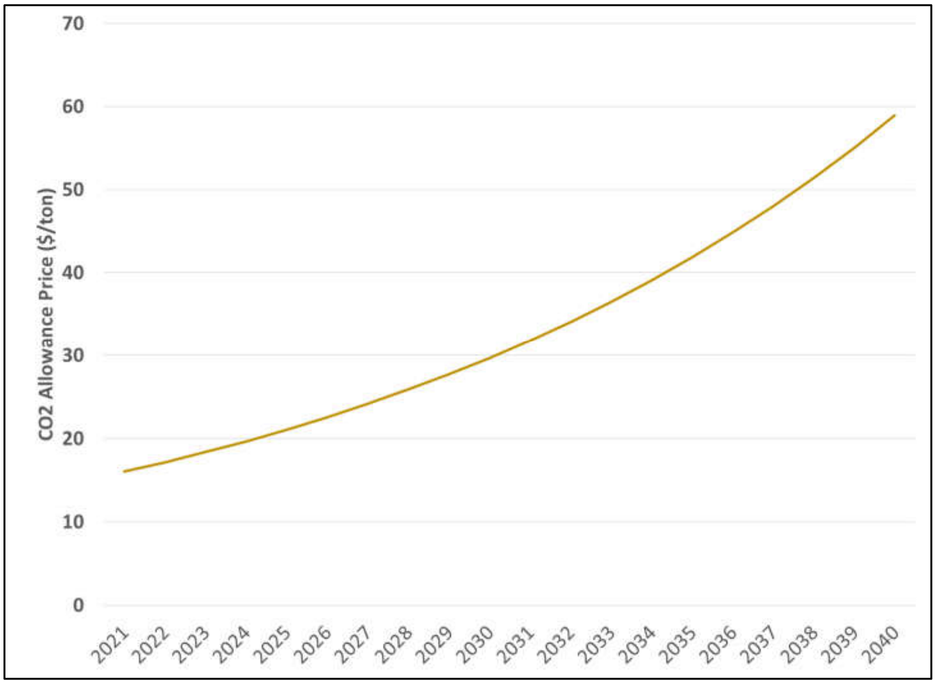
For the CO_2 allowance price forecast, Concentric relied on a projection prepared by the vendor of the AURORAxmp model, EPIS. For New England, EPIS modeled the Regional Greenhouse Gas Initiative ("RGGI") regional budget for the power sector to obtain a RGGI participating state projection of CO_2 allowance prices, as shown in Figure 5.[34,35]

[33] Prices in this section are expressed in nominal dollars unless otherwise indicated.

[34] Participating RGGI states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont.

[35] The Clean Power Plan, finalized in October of 2015, requires each state to hit a CO_2 target by 2030, with reductions to begin in 2022. States have the option to comply with CO_2 rate targets by way of a lb/MWh or a mass-based target, the latter being in part included to encourage inter-state emissions trading through initiatives such as RGGI.

Figure 5: Forecast of CO_2 Allowance Prices

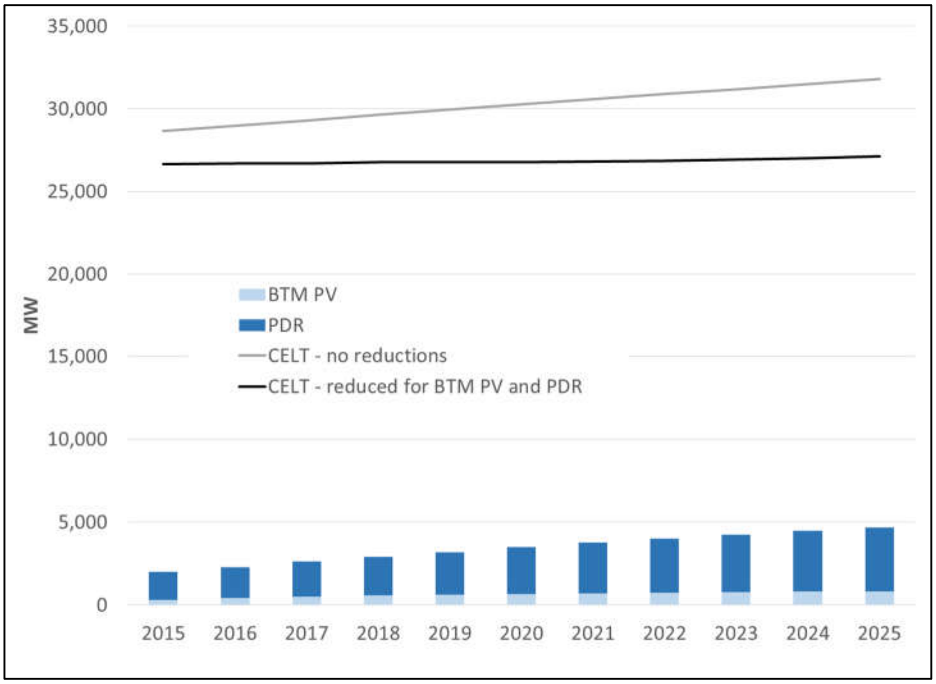


LOAD FORECAST

The forecast of peak loads was based on the 2016 Capacity, Energy, Load, and Transmission ("2016 CELT") report, published by ISO-NE. For that forecast, ISO-NE develops a forecast of total electric demand, which is then adjusted downward to account for Passive Demand Response ("PDR") as well as "behind the meter" photovoltaic ("BTM PV") capacity.[36] Those forecasts are shown in Figure 6.

[36] BTM PV is photovoltaic capacity installed at customer locations that generally serves to reduce customer demand from the grid rather than add generation to the system. Rooftop solar is an example of BTM PV.

Figure 6: CELT 2016 Load Forecast



For purposes of the market simulation, the load forecast that is adjusted for BTM PV and PDR was utilized. The 2016 CELT provides a forecast through 2025. Thereafter, the forecast was adjusted for by linear extrapolation. The extrapolation calls for annual load growth, net of BTM PV and PDR, of approximately -0.2% beginning in 2026.

Conversion of the CELT forecast is based on historical load shapes for multiple years which are averaged and normalized. For this analysis, hourly load data for the period 2011-2013 were utilized. The synthetic load shape that results is adjusted such that both the peak demand (in MW) and the energy demand (in GWh) contained in the CELT report are met in each year.

NEW GENERATION ADDITIONS

Plants were added to the Aurora simulation of future LMPs based on one of several criteria. *First*, plants that had already cleared a capacity auction and had a Capacity Supply Obligation ("CSO") were added to the generation supply. These plants include the Salem Harbor CC, the West Medway Peaker, the Canal 3 unit, and others. All such plants were added prior to the start of the forecast period.

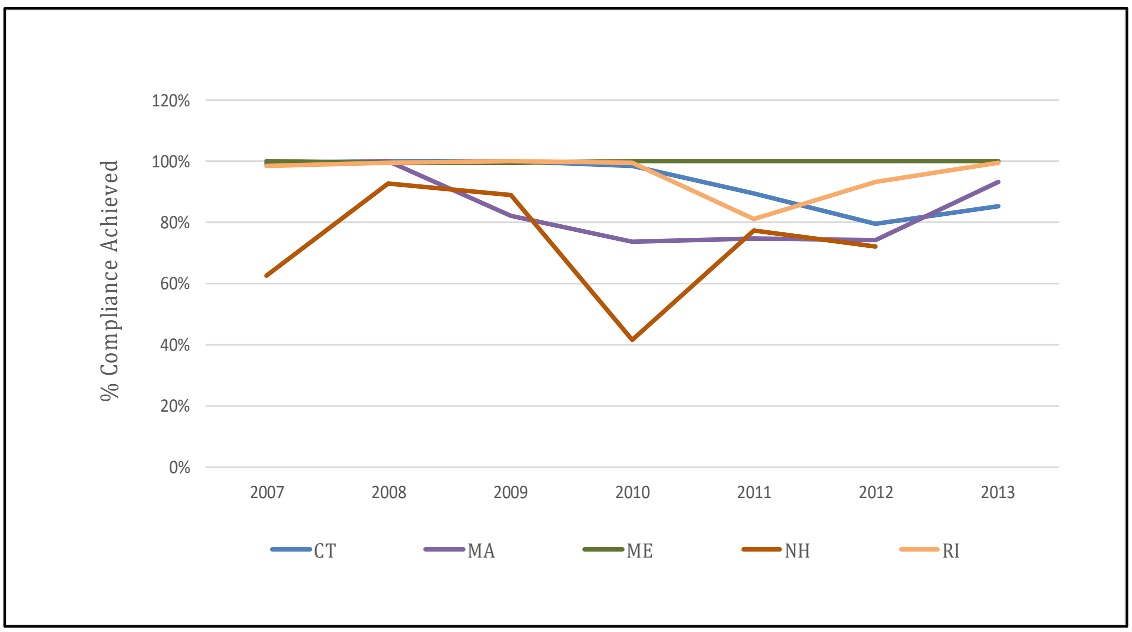
Second, renewable resources are added over the forecast period. For photovoltaic ("PV") resources, utility-scale plants that have CSOs were added to the generation mix. Following 2019/20, wind capacity was deemed to be more economical than PV for utility-side generation; thus, beginning in 2020/21, all incremental PV was assumed to be added on a BTM basis and was assumed to grow at the same rate as demand.

For wind resources, those plants that had CSOs were added to the generation mix. Additionally, Concentric sought to address the legislative mandate in Massachusetts for EDCs to solicit up to 1,600

MW of offshore wind, provided that such resources are "cost effective".[37] Based on previous experience in Massachusetts and experience in other states, we have determined that a successful solicitation of the full amount authorized is unlikely.[38] Instead, we have added an offshore wind facility to the generation mix based on an existing project currently in development whose size is approximately 25% of the total offshore capacity authorized in Massachusetts legislation. The offshore facility was added at the beginning of the 2027/28 delivery period, the date mandated by the legislation.

Other wind resources are added over the forecast period to meet load growth.[39] This assumption recognizes two important realities – i) the degree to which state Renewable Portfolio Standards ("RPS") targets are achieved is not simply a function of state mandates, but rather a combination of forces that can affect the ability of states to meet the mandated RPS requirement in any particular year, as shown in Figure 7 below; and ii) there are ways to meet the RPS mandates that don't necessarily involve building renewable facilities so assuming that mandates will be met with new renewable facilities will likely overstate the amount of renewable capacity coming into the market over the forecast period.

Figure 7: Total New England RPS Achievement



[37] Bill H.4568 was signed into law in August 2016. The new law inserts a new section, 83C, into the Green Communities Act, requiring that EDCs procure approximately 1,200 MW of renewable energy and additionally provides for separate authorization (not requirement) to procure up to 1,600MW of offshore wind, providing that such a procurement can be accomplished on a "reasonable" and "cost effective" basis. Because of the requirement for cost effectiveness, it has been assumed that procurement of the full 1,600 MW would not be achieved. Instead, we have chosen to add a resource to the generation mix of roughly 25%.

[38] The Deepwater Wind facility is expected to be commercialized later in 2016. When it is brought online, it will be the first offshore wind facility operating in New England. Since Deepwater received a CSO in FCA10, it is included in the simulation model.

[39] Wind resources are added in discrete increments of 50 MW; thus, wind resources are not necessarily added in every year of the forecast.

Third, in later years of the forecast, generic gas-fired generation was added to the capacity mix to maintain a reserve margin of 15% in each load zone for reliability purposes. Such resources were added in 2021, 2023, 2025, 2026, 2030, 2031, 2033, 2036, and 2037.

PLANT RETIREMENTS

The retirement of plants is also a multi-step process. *First*, those plants that have announced their intention to retire and do not have a CSO for a future commitment period were removed from the generation mix. These included Bridgeport Harbor, Brayton Point, and the Pilgrim Nuclear Generation Station, and others, all of which retire prior to the beginning of the forecast.

Second, older nuclear plants were retired at the end of the current operating licenses. These include Seabrook and Millstone 2.[40]

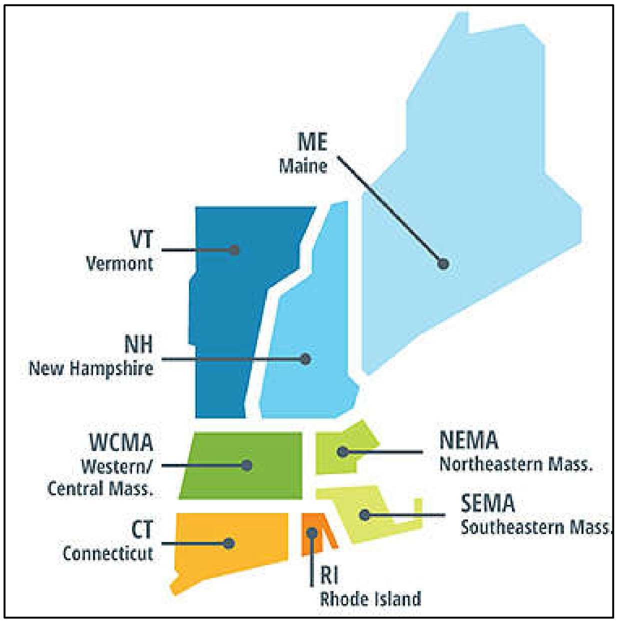
Third, later in the forecast, plants were retired for economic reasons. AURORA includes an iterative, endogenous retirement function that compares the avoidable, going-forward cost of owning and operating a facility to the net revenues (*e.g.* energy revenues minus costs) to be earned by the facility based on the market outlook contained in the forecast. If going-forward costs are expected to be greater than net revenues on a present value basis, the plant is retired. Typically, such retirements are applied to older, non-gas units. These included Canal 1 and Canal 2, Mystic 7, Yarmouth 1-4, and others.

TRANSMISSION TOPOLOGY

For purposes of the price forecast, the simulation model was run in a zonal configuration reflecting the New England load zones. A map of the zones is shown in Figure 8 below.

[40] There are two operational reactors at the Millstone facility, Millstone 2 and Millstone 3. The operating license for Millstone 2 expires in 2035 and was removed from the simulation in that year. Millstone 3 holds an Extended Operating License that runs through 2045 and was therefore not removed.

Figure 8: ISO-NE Load Zones[41]



Transfer limits between zones are based on data obtained from ISO-NE, which are shown in Table 29.

Table 29: Transfer Limits Between Load Zones

Interface	Limit (MW)		Interface	Limit (MW)
Boston_Import(I)	5700		**NH_VT(II)**	1025
SEMA_RI_Export	3400		**WCMA_CT(III)**	930
SEMA_RI_Import	1280		**RI_CT**	750
CT_Import	2950		**NEMA_SEMA(IV)**	1500
North_South(I)	2675		**WCMA_NEMA**	2500
ME_NH	2000		**WCMA_VT**	900
(I) After the Boston Upgrade Project completion				
(II) Not rated in the opposite direction				
(III) 1030 MW in the opposite direction				
(IV) 750 MW in the opposite direction				

The Greater Boston Upgrades project was assumed to be in place in 2019, with a net increase of 850 MW on the Boston Import interface (N-1), and 575 MW increase on the North-South Interface.[42]

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[41] ISO-NE.

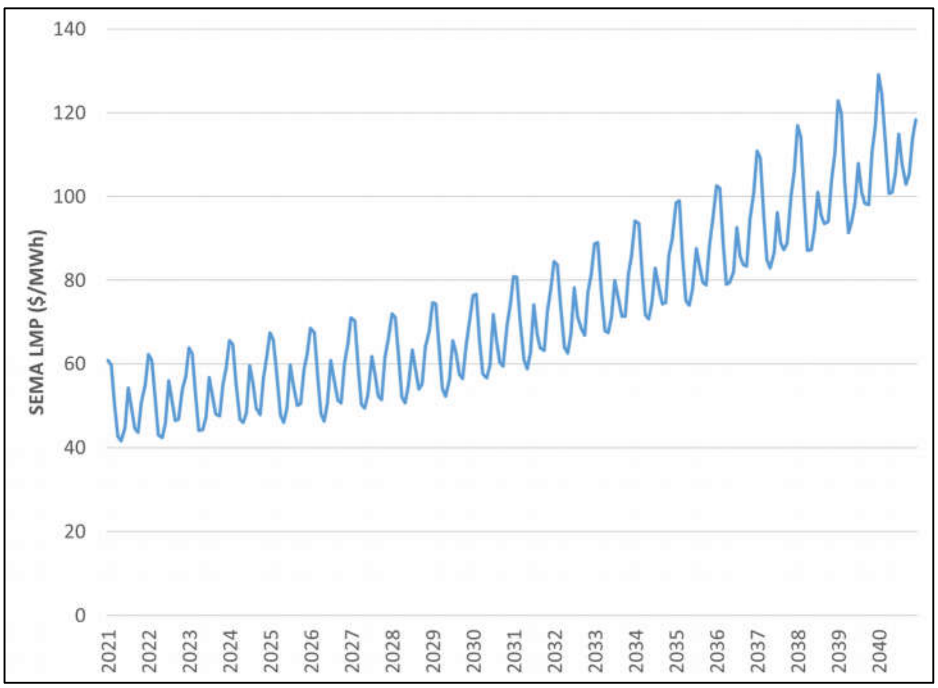
[42] ISO-NE Planning Advisor Committee, "Forward Capacity Auction 11, Transmission Transfer Capabilities & Capacity Zone Development", March 22, 2016.

In addition, transmission links with neighboring regions outside of New England were modeled. For the forecast, all external transmission links were held constant[43] with one exception, the addition of a 1,000 MW transmission line between New Hampshire and Quebec, consistent with Section 83C of the Massachusetts Green Communities Act, which *authorizes* the Massachusetts EDCs to contract for offshore wind provided that doing so is cost effective but *requires* contracting for 1,200 MW of land-based renewables. Based on an analysis of market options as well as a review of existing proposed transmission projects, it was determined that the most likely avenue of compliance for the EDCs was the development of a transmission asset to import renewable energy from Canada, where hydroelectric power is abundant and inexpensive. Additionally, significant commercial interest in such projects predates the enactment of Section 83C.

The 1,000 MW line is installed at the beginning of the forecast as an "energy-only" resource. That is to say that there is no capacity associated with the line that contributes to the region's ability to maintain reserve margins. There are no transmission upgrades associated with the project that would affect transfer limits between the zones within New England.[44]

Based on the above assumptions, a forecast of LMPs for SEMA was developed, as shown in Figure 9 below.

Figure 9: SEMA LMP Forecast



[43] Transfer limits used are consistent with those contained in the 2015 Regional System Plan.

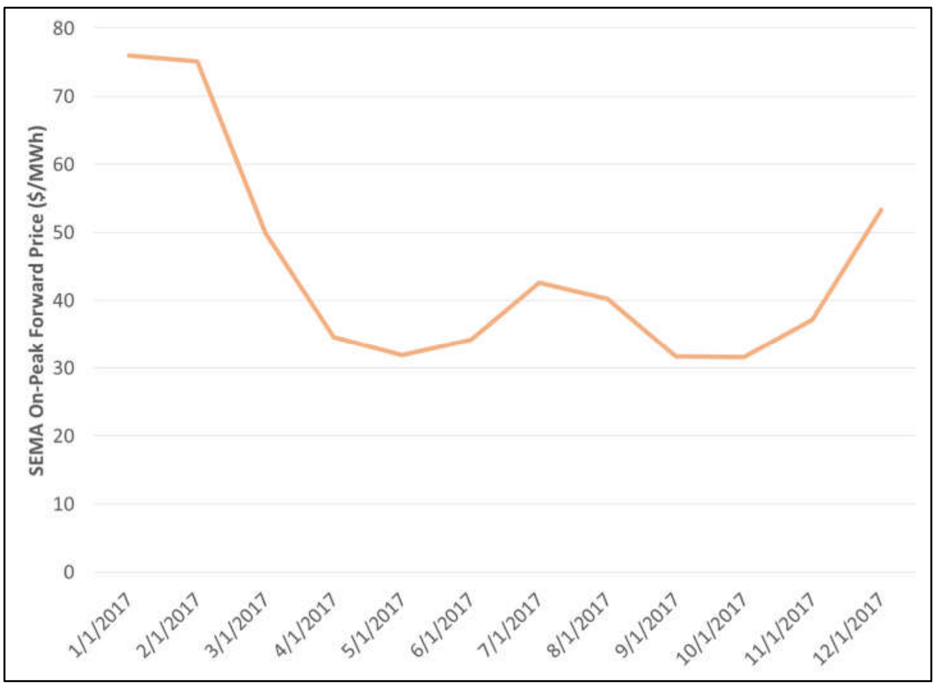
[44] The most current information available regarding transfer limits and the effect of new import projects on those limits is the analysis conducted by ISO-NE's Planning Advisory Committee (PAC), which were made public in March 2016. At that time, the PAC found that transfer limits for FCA 11 would be unaffected by the installation of a transmission project between Ontario and New Hampshire. The project being reviewed by the PAC is similar to the one being contemplated for purposes of this analysis. The PAC findings are available at https://www.iso-ne.com/static-assets/documents/2016/03/a2_fca11_zonal_boundary_determinations.pdf.

Generally, the forecast follows the contours of the gas price forecast shown in Figure 3. Prices rise moderately through approximately 2030, and more rapidly thereafter, following the same trend in the gas price forecast.

FORECAST VALIDATION

The forecast indicates an expectation of winter-peaking prices, with a smaller peak during the summer months. This is a departure from historical pricing patterns in New England, in which prices were generally higher in the summer, and are primarily due to higher levels of seasonal price differentials in the gas price. This finding has been validated by review of settlements for New England LMP indices in the forward market, which reflect the same expectation in the market. Figure 10 shows the curve for 2017 settlements for on-peak LMPs in SEMA traded on the Intercontinental Exchange ("ICE") on September 23, 2016.[45] Note the significant peak in the winter months and a smaller peak during July and August.

Figure 10: 2017 Settlements for On-Peak SEMA LMPs

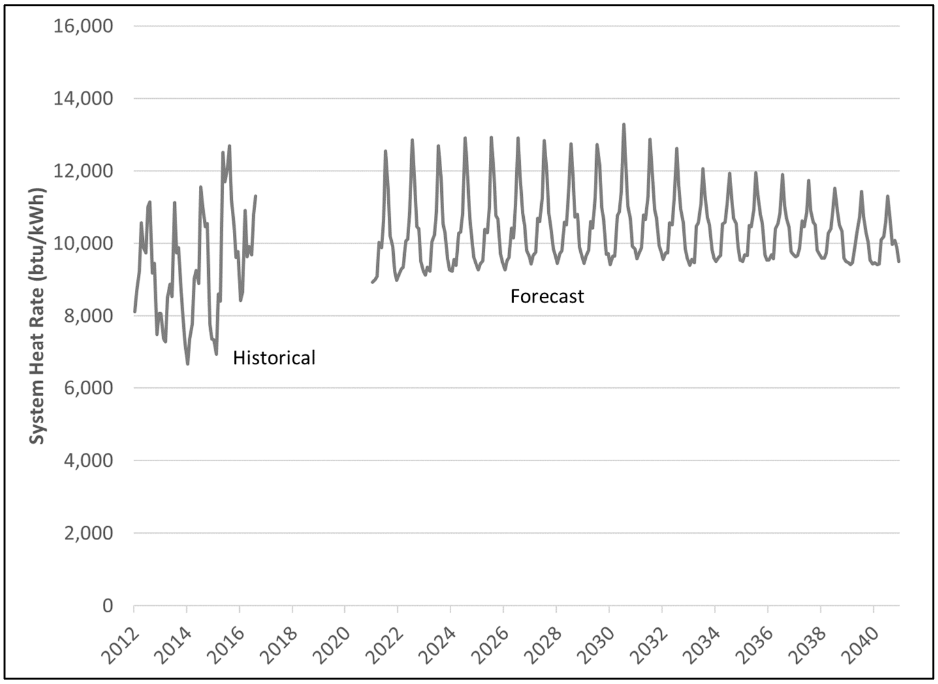


An analysis of System Heat Rates ("SHRs") was utilized to further validate the forecast. SHRs are the relationship between market gas and market power prices. For any hour, the SHR is equal to the ratio of the LMP, in $/MWh, and the gas price, in $/MMBtu.[46] Figure 11 shows the comparison of historical SHRs for SEMA, calculated using the ratio of the average monthly SEMA price to the average

[45] ICE contract code IMB.
[46] The result is then multiplied by 1,000, since SHRs are most typically expressed in btu/kWh.

monthly Algonquin CG price, to the forecast SHRs, calculated by the same ratio using the price curves shown in Figure 3 and Figure 9.[47]

Figure 11: Comparison of Historical to Forecast SHRs



The historical period shows a trend of rising SHRs, indicating a "tightening" market in which demand is growing more quickly than generation supply. SHRs in the beginning of the forecast are generally consistent with those observed at the end of the historical period, and remain so through the late 2020s. Thereafter, SHRs begin to fall due to three factors. First, renewables, primarily in the form of new wind entry and BTM PV are added over the course of the forecast, providing an inexpensive source of energy. Second, as older, inefficient plants retire, as described above, they are replaced with new, modern, gas-fired units, which are more economical and increase the efficiency of the market. Third, load growth, net of the adjustments described above is lower than historical rates throughout the forecast.

ANCILLARY SERVICES PAYMENT RATES

Generators in New England can receive payments for voltage regulation, Net Commitment Period Compensation ("NCPC"), Locations Forward Reserves ("LFR"), and Real-time Reserves ("RTR"). A simple cycle frame machine will not be expected to receive payments for regulation; therefore, this revenue stream is excluded from the estimate ancillary service ("AS") revenues. Simple cycle machines are likely to receive very little in NCPC payments; these "make whole" payments are designed to compensate less flexible generators that are dispatched out of economic merit to provide reliability services to the market, thus incurring losses. Since our LMP and revenue forecasts are

[47] Data used to calculate the historical SHRs provided by SNL.

developed on an hourly basis and do not dispatch facilities out of merit, no such losses are incurred. Therefore, NCPC payments are excluded from the estimate of AS revenues.

A new simple cycle machine will be expected to provide LFR and RTR and thus receive compensation from the market for these services. To estimate the rates at which this unit would be paid for the services, average payment rates were developed based on historical clearing prices in the reserve markets.

Locational Forward Reserve Market ("LFRM"): For each of the five commitment periods beginning with 2011/2012 through 2015/2016, a seasonal-weighted average clearing price was calculated for each product using the rest of system clearing prices (the location of the reference unit). The FCM clearing price was then subtracted from this result to obtain an annual average LFRM price, in units of $ per MW-month. This annual average LFRM price was then divided by the average on-peak hours each month to give the average annual LFRM price in units of $ per MWh. The results for each of the five commitment periods are shown below. We computed a final 'Mid-3' annual average by taking the average of the three annual values after excluding the highest and lowest outliers. The resulting values are shown in the table below.

Table 30: Forward Reserve Seasonal Average Clearing Prices

Period	LFRM TMNSR ($/MWh)	LFRM TMOR ($/MWh)
2011-12	2.38	2.38
2012-13	1.19	1.19
2013-14	13.88	9.60
2014-15	20.89	20.89
2015-16	6.35	6.35
Mid-3 Average	**7.54**	**6.11**

Prior to applying the rates above in the E&AS model, an adjustment was made to account for penalties in the LFRM. The E&AS model does adjust revenues to account for expected unit availability – for example, it is assumed that the unit will not be 100% available for dispatch over the life of the unit. However, this does not fully account for failure to reserve penalties due to other conditions. Actual LFRM penalties assessed to participants with gas-fired resources that regularly participate in the LFRM were analyzed over the five-year study period (corresponding to the total period covered in the tables above). The failure to reserve MWh averaged 2.1% of the total LFRM obligation MWh for the LFRM participants using (only) gas turbine resources to meet their LFRM Obligations. The average penalty charges (in dollars) were 3.5% of revenues earned by generators providing LFR.[48] Accordingly, the LFRM average revenue values described in the tables immediately above were

[48] The failure-to-reserve penalty rate is the maximum value of 1.5 multiplied by the LFRM payment rate, or the RTR Rate minus the LFRM payment rate. The Failure-to-Activate penalty rate is the maximum of 2.25 multiplied by the FRM Payment Rate, or the applicable nodal LMP.

adjusted by 3.5% to account for the penalties that could be reasonably expected in the LFRM for a simple cycle machine.

Real-Time Reserve Market: For each of the five commitment periods beginning with 2011/2012 through 2015/2016, an average RTR clearing price was calculated for each RTR product for all off-peak hours.[49] Consistent with the LFRM calculations, a 'Mid-3' annual average was calculated using the three annual values that exclude the highest and lowest outliers. The resulting values are shown in the table below, and were applied in the E&AS model.

Table 31: Real-Time Reserve Average Clearing Prices in $/MWh

Average Off-Peak Clearing Price	RTR TMNSR ($/MWh)	RTR TMOR ($/MWh)
2011/12	0.05	0.05
2012/13	0.67	0.66
2013/14	1.97	1.70
2014/15	0.96	0.96
2015/16	0.39	0.39
Mid-3 Average	**0.67**	**0.67**

REVENUE FORECAST - SIMPLE CYCLE FRAME COMBUSTION TURBINE

Revenues for the simple cycle frame combustion turbine were estimated using a calculation that approximates a simplified dispatch regime for the facility. In any hour, the unit can receive payments for the sale of one of more of FR, energy, and/or RTR. Derivation of expected sales and net revenues for each payment stream are described below:

Locational Forward Reserves

Simple cycle frame combustion turbines are paid for LFR during weekday, on-peak hours, excluding NERC holidays (hereinafter "LFR hours"). On-peak hours are defined as the 16 hours beginning with the eighth hour of the day and ending with the twenty-third hour of the day. In consultation with experts at the General Electric Company (the vendor of the reference technology), it was determined that 30% of the unit's 338 MW unit capability can be delivered from a cold start in 10 minutes and the remaining capability can be delivered in 30 minutes. Therefore, in each eligible LFR hour, a simple cycle frame combustion turbine is expected to receive a payment of $7.54/MWh for 100 MW of 10-minute non-spinning reserve and $6.11 for 238 MW of 30-minute operating reserve, adjusted for inflation, multiplied by its annual expected availability rate, which is assumed to be 97%.

Energy

During LFRM hours, a simple cycle frame combustion turbine is required to offer its energy into the market at a price equal to or greater than a defined threshold daily Price. The threshold daily price

[49] Off-peak hours are hours ending 1 through 7 and 23, on non-NERC holiday weekdays.

is a function of the natural gas price and the LFRM heat rate, which is calculated and published by ISO-NE.

For the revenue estimate, the latest available LFRM heat rates were held constant for the forecast period. Those heat rates are shown in Table 32:

Table 32: Locational Forward Reserve Heat Rates

SEASON[50]	LOCATIONAL FORWARD RESERVE HEAT RATE (BTU/KWH)
Summer	17,539
Winter	19,935

Thus, for each day of the forecast, the threshold daily price is calculated as the product of the applicable LFRM heat rate and the gas price in SEMA.

The unit is assumed to sell energy and receive revenues during LFRM hours if the LMP is higher than the threshold daily price *and* if the LMP is high enough to cover the unit's operating costs, which include the gas cost, its cost of CO_2, and its VOM. Each unit's gas cost is calculated as the gas price multiplied by its operating heat rate (rather than the LFRM heat rate).

During non-LFRM hours, the unit will sell energy and receive revenues in any hour in which its operating costs are lower than the LMP. During non-LFRM hours, there is no requirement that the unit offer energy at the threshold daily price.

In any hour in which the plant sells energy, its revenues are equal to the difference of the LMP less its operating costs (natural gas, VOM, and CO_2), multiplied by its capacity multiplied by its availability. Revenues are based on the unit's actual operating heat rate rather than the LFRM heat rate.

Real-time Reserves

For any non-LFRM hour, the plant will be paid for RT reserves if it is not operating in the energy market. Payments for such hours is equal to the applicable RT payment rate multiplied by its capacity for each product (10-minute or 30-minute) multiplied by its availability.

REVENUE FORECAST – COMBINED CYCLE, AERO, & HYBRID

The process by which the E&AS offset is calculated for other candidate reference technologies is similar to the calculation for the simple cycle frame combustion turbine. The same LMP and gas forecasts are used, the gas-turbines are dispatched in the same manner, and the process by which the cash flows are levelized to calculate the offset remains the same. Variations in the procedure for each technology are described below.

Combined Cycle – The combined cycle combustion turbine has different operating characteristics than the simple cycle units, which are input into the energy revenues algorithm. Additionally, analysis of historical data indicates that combined cycle units earn the wide majority of their revenues from the

[50] For FR, the Summer Reserve Period runs June through September and the Winter Reserve Period is all remaining months.

sale of energy, rather than from the sale of AS, and that AS revenues are reasonably predictable if energy revenues are known. Based on this analysis, the AS adder for a combined cycle machine is assumed to be equal to 0.9% of its energy revenues.

LM6000 and LMS100 – Both the LM6000 and LMS100 have different operating characteristics than the simple cycle frame unit, which are input into the energy revenues algorithm. The AS assumption for each is the same as for the simple cycle frame unit.

2. Pay for Performance

ISO-NE's pay for performance ("PFP") mechanism is designed to encourage resource performance consistent with its assumed capacity obligation. Under PFP, a resource that underperforms will forfeit some or all capacity payments awarded in a FCA. Resources that perform in its place will receive these capacity payments. Exposing resource owners to the risk of forfeiting capacity payments for underperformance, as well as providing them the opportunity to receive more compensation for over performance, is designed to incent resource owners to make investments that ensure their resource can perform.

In calculating expected compensation for CONE technologies, we consulted with ISO-NE and stakeholders, and reviewed and discussed ISO-NE's most recent study on expected system conditions and shortage hours over the life of the generating facilities. A review of historical data shows relatively few shortage hours since the PFP mechanism was implemented. However, it is important to note that the objective of the CONE/Net CONE analysis is to calculate what a merchant developer would need to enter the market given reasonable expectations of future system conditions. Historical data reflects a system that has enjoyed substantial excess capacity of approximately 3,000 MW, so that using this data to extrapolate future system conditions is not appropriate.

In fact, ISO-NE's recently released shortage hour event analysis shows relatively few shortage hours in the near term. However, it is expected that much of the existing capacity excess, which began to dissipate over the most recent three capacity auctions and now stands at 1,416 MW, will continue to decrease over time. Beyond year three, ISO-NE does not expect current excess capacity conditions to persist and is modeling a system at equilibrium after the three-year transition period to the new FCM demand curve system ends. This is consistent with our stated assumption of calculating CONE/Net CONE under long-term equilibrium conditions.

Based on ISO-NE's most recently published analysis, we have assumed six shortage hours for years one through three by extrapolating between the shortage hour values at a capacity surplus of 1,200 MW and 1,600 MW as shown in the ISO-NE analysis.[51] For years four and beyond, we have assumed a system at equilibrium with assumed shortage events at 11.3 hours per year. We have assumed penalty rates of $3,500/MWh for years one through three, and $5,455/MWh beginning in year four consistent with rates filed and accepted by the FERC in ISO-NE's PFP filing.[52] This penalty rate was not recalculated based on the new shortage hour analysis since it is not a formulaic rate but rather a

[51] ISO-NE Power Supply Planning Committee Presentation, https://www.iso-ne.com/static-assets/documents/2016/10/PSPC10132016_A2_2020-21_Reserve_Deficiencies_Hours_Final.pdf.
[52] ISO-NE Pay for Performance FERC Filing in Docket No. ER14-1050-000.

filed rate with the FERC. Therefore, a recalculation would be speculative at this time. A balancing ratio of 0.85 was used, consistent with previous ISO-NE analysis.

We have assumed a performance score of 0.92 for a combined-cycle machine based on ISO-NE analysis this technology.[53] For a simple cycle machine, we have assumed a performance score of 0.98 consistent with the expected forced outage rate for this technology based on consultation with MM and the assumption that a state-of-the-art fast-start unit would generally be expected to capture shortage hour revenues unless on a forced outage. Our shortage hour assumptions are shown in Table 33 below.

Table 33: Shortage Hour Assumptions

Technology	Scarcity Hours (hrs)	Performance Payment Rate ($/MWh)	Average Actual Performance (%)	Average Balancing Ratio (%)	Net Performance Payments ($/kW-mo)	
Combined Cycle	11.3	$5,455	0.92	0.85	0.36	years 4 - 20
Combustion Turbine			0.98		0.67	
Combined Cycle	6	$3,500	0.92	0.85	0.12	years 1-3
Combustion Turbine			0.98		0.23	

LEVELIZATION

Levelization of the E&AS revenues is conducted in the same manner as the other cash flows of relevance. The total levelized value of the E&AS offset for the simple cycle frame combustion turbine is $3.31/kW-month, as shown in Table 34 below. This is comprised of $0.25/kW-month for energy, $2.58/kW-month for ancillary services, and $0.48/kW-month for PFP.

Table 34: Levelized Offset by Technology

Levelized Offset (2021$/kW-mo)	Energy	Ancillary Services	PFP	Total
Combustion Turbine	0.25	2.58	0.48	3.31
Combined Cycle	5.31	0.05	0.26	5.62
Aero	0.22	2.93	0.48	3.63
Hybrid	0.26	2.93	0.48	3.67

[53] Testimony of Dr. Matthew White, Docket No. ER14-1050-000, January 17, 2014, pg 110.

G. CONE/NET CONE CALCULATION AND RESULTS

The CONE/Net CONE is calculated as the revenue required for entry in the first year of operation, or CONE, less the expected first year revenue offsets. A summary of the CONE/Net CONE values for the evaluated technologies are shown in Table 35 below.

Table 35: Net CONE Summary for Candidate Reference Technologies (2021$)

Reference Technology	Installed Capacity (MW)	Installed Cost (000$)	Installed Cost ($/kW)	ATWACC (%)	Fixed O&M ($/kW-mo)	Gross CONE ($/kW-mo)	Revenue Offsets ($/kW-mo)	Net CONE ($/kW-mo)
1x1 7HA.02 (CC)	533	$598,958	$1,124	8.1	$5.01	$15.62	$5.62	$ 10.00
1x0 7HA.02 (CT)	338	$304,179	$900	8.1	$3.21	$11.35	$3.31	$ 8.04
2x0 LM6000 PF+ (Aero)	94	$198,363	$2,110	8.1	$6.96	$25.98	$3.63	$ 22.35
1x0 LMS100PA (Advanced Aero)	103	$174,644	$1,696	8.1	$5.75	$21.03	$3.67	$ 17.36

Based on our analysis, we recommend that the simple cycle frame combustion turbine be used as the reference technology for FCA-12. The simple cycle frame machine is substantially less expensive than the combined cycle machine and the aeroderivative machines, and is an established technology in New England. While this represents a change from the selection of the combined cycle combustion turbine as the reference technology during the last CONE/Net CONE update in 2014, there have been significant changes to the market design that favor the selection of the simple cycle reference technology at this time.[54] First, the implementation of an MRI-based system and zonal demand curves, and the concurrent elimination of the administrative pricing rules has eliminated the concern that deficiencies in the capacity market rules could result in systemic under-procurement.[55] In addition, there have been other important capacity, energy, and reserve market changes that are likely to favor the development of more flexible resources such as those represented by the simple cycle reference technology. In addition to the implementation of PFP, at the Commission's direction, reserve constraint penalty factors were increased substantially at the end of 2014, which produces higher reserve market prices during scarcity conditions. In addition, in 2012 and in 2013, the ISO increased overall reserve requirements (in the real-time and forward reserve markets, respectively) to account for historical reserve non-performance rates; these changes increase overall reserve revenues and primarily benefit flexible, fast-start resources, such as the simple cycle combustion turbine.[56] Finally, in early 2017 new energy market rules will take effect that improve real-time price

[54] In the 2014 CONE Order at P 34, the Commission recognized that periodic reevaluation of the reference technology is important "since market activity and technology change over time."

[55] These changes are effective beginning with FCA 11. *See* ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Filing, 155 FERC ¶ 61,319 (2016). The interactions between the MRI-based demand curves and Net CONE were discussed extensively in the answer that the ISO submitted in the zonal demand curve proceeding in mid-2016. *See* Section B of Motion for Leave to Answer and Answer of ISO New England Inc. at pp. 7-14, Docket No. ER16-1434, submitted May 27, 2016.

[56] These reserve market changes were not fully accounted for when the CONE/Net CONE values were last updated in 2014. The overall impact of the changes is to increase the overall reserve market revenues for a CT resource and, in particular, the expected forward reserve market revenues.

formation when fast-start resources are deployed. Taken together, these market changes make simple cycle combustion resources considerably more attractive financially to potential project developers now than at the time of the 2014 Net CONE study, as the recent entry and clearing of these technologies in the FCM attests. Accordingly, these changes further support the selection of the simple cycle frame combustion turbine as the reference technology for the CONE/Net CONE values going forward.

H. CONE ANNUAL UPDATE PROCESS

1. E&AS Revenues

Periodically, the E&AS offset is updated to reflect changes in expectations regarding the profitability of merchant generators entering the market. The current procedure is described in Market Rule 1 Section III.13.2.4.[57]

Concentric is proposing a change to the update procedure that relies on publicly available forward prices to quantify the change in profitability expectations. For the reference unit, profitability is a function of the spread between electric prices and delivered gas prices. Therefore, the E&AS update will be based on changes to the relationship between electric forwards and gas forwards, both of which are publicly available from ICE. Calculations will be based on settlements for the 2021/2022, which is currently the farthest date forward in time for which power settlements are available.

Calculations will be based on three contracts on ICE, an Algonquin Citygate basis swap, the Henry Hub futures price, and the MassHub Day-Ahead On-Peak Future. The basis swap is added to the Henry Hub futures prices to create an index for a delivered Algonquin CG price. The ratio of the power price to the delivered gas price is then calculated for each month, after which the twelve-monthly ratios are averaged. Table 36 shows the calculation using settlements on ICE from September 23, 2016.

[57] The offset update is also described in Appendix A Section 21.1.2.e(4) of Market Rule 1 Appendix A Section 1.1.2.e(4).

Table 36: Calculation of Power: Gas Ratio for E&AS Offset Update

	a	*b*	*a+b = c*	*d*	*e = d/c*
	Henry Hub (H) *($/MMBtu)*	**Algonquin CG Basis (ALQ)** *($/MMBtu)*	**Algonquin CG Delivered** *($/MMBtu)*	**MassHub On-Peak (NEP)** *($/MWh)*	**Ratio**
Jun 2021	2.875	(0.425)	2.450	34.45	14.061
Jul 2021	2.912	0.105	3.017	40.80	13.523
Aug 2021	2.946	(0.033)	2.914	38.70	13.283
Sep 2021	2.951	(0.568)	2.384	30.40	12.754
Oct 2021	2.990	(0.448)	2.543	32.80	12.901
Nov 2021	3.072	0.310	3.382	40.85	12.079
Dec 2021	3.237	2.340	5.577	55.80	10.005
Jan 2022	3.398	4.628	8.026	80.00	9.968
Feb 2022	3.363	4.540	7.903	77.40	9.794
Mar 2022	3.298	1.775	5.073	47.25	9.314
Apr 2022	3.003	(0.175)	2.828	37.85	13.384
May 2022	2.998	(0.358)	2.641	30.75	11.646
			Average		**11.893**

In the future, these calculations will be performed again using the same indices and for the same settlement periods. The average ratio that results will be compared to the ratio shown above. The percentage difference (positive or negative) in the ratios will be applied to the E&AS offset.

2. Capital and Fixed Costs Updates

Pursuant to Tariff requirements, for years in which no full recalculation of CONE/Net CONE values is performed, the CONE/Net CONE values associated with the reference technology will be updated pursuant to the cost indices contained in Market Rule 1 Section III.A.21.2. for each relevant cost component. Indices covering the most recent 12 months at the time will be compared against the current values to calculate the appropriate escalation rates.

SECTION 4:
ORTP STUDY

A. INTRODUCTION

ISO-NE ensures that sufficient resources are available to meet future demand for electricity through the FCM. Under the FCM design, auctions are held annually, three years in advance of the period during which resources must deliver their capacity. Resources compete in the auctions to obtain a commitment to supply capacity in exchange for a market-priced capacity payment. These payments support the development of new resources and retain existing resources when and where they are needed.

The FCM design includes a mechanism to protect against the price suppressing effects of uncompetitive new resource offers. This mechanism subjects all new entrants in the FCA to a benchmark known as the ORTP. The ORTP acts as a "screen" for potentially new uncompetitive resources offers in an FCA. It does so by setting benchmark prices intended to represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. New supply offers above the ORTP level are presumed to be competitive and not an attempt to suppress the auction clearing price, while offers below the ORTP level must be reviewed by the IMM pursuant to a unit-specific review process. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

B. APPROACH

The objective of this ORTP study was to develop updated ORTP values for FCA-12 for a 2021/2022 Commitment Period. Consistent with guidance from ISO-NE and FERC, the recommended ORTPs presented in this report were set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues. In addition, consistent with Tariff requirements, all resources were assumed to have a contract for their output.[58]

The study process consisted of the four basic tasks outlined below and further described in the balance of this report:

1. **Resource Screening and Selection**. The first step in the process was the development of screening criteria for the selection of resource types for which to calculate an ORTP. Those resources that passed the screen were subject to a full evaluation of costs and revenues over the expected life of the facility
2. **Calculation of CONE.** Recognizing the low end of the competitive range requirement for the ORTP values, we developed technical specifications, installed capital costs and operating costs over the 20-year expected life of the facility (11 years for Energy Efficiency and Demand Response) for each of the selected technologies. Based on

[58] Market Rule 1 Appendix A Section III.A.21.1.2

reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we calculated a first-year revenue requirement that ensured the recovery on and of investment costs.

3. **Calculation of Expected Revenues.** We estimated expected revenues for each of the selected technologies, including energy revenues (net of variable costs), ancillary service revenues, REC revenues and pay for performance PFP revenues.
4. **Calculation of Net CONE.** Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market in the first year of operation (2021) at a net present value of zero over the forecast period. This Net CONE represents the recommended ORTP level.

Each of these tasks involved a detailed review of historical data, forecast of future prices, and professional judgement in order to calculate benchmark prices for each technology. These parameters were informed through consultation with ISO-NE and stakeholders in five separate meetings in order to ensure the effectiveness and appropriateness of the methods and data used.

C. RESOURCE SCREENING CRITERIA, PROCESS AND SELECTION

We began our ORTP study by establishing the criteria against which we would screen potential resources for the calculation of an ORTP value. The screening criteria used and reviewed with stakeholders are consistent with the criteria accepted by the FERC in the 2013 ORTP study, and are as follows:

- Must represent technologies that have been installed in the region and participated in recent FCAs;
- Must have reliable cost information available to calculate an ORTP using a full "bottom-up" analytical approach;
- Must have a first-year revenue requirement below the FCA starting price.

These criteria were applied consistently to potential resources identified in consultation with stakeholders. Ultimately, the criteria were used to select a subset of resources for which a full evaluation would be conducted and an ORTP would be established. Resources that were considered in the screening process, and the outcome of that process are shown in Table 37 below.

Table 37: Resource Screening Results

Technology Type	Installed in New England and Participated in Recent FCAs *	Reliable "Bottom Up" Cost Data	1st Year Revenue Requirements < FCA Starting Price
Simple Cycle Gas Turbine	Yes	Yes	Yes
Combined Cycle Gas Turbine	Yes	Yes	Yes
On-Shore Wind	Yes	Yes	Yes
Solar	Yes	Yes	Yes
Biomass	Yes	No	N/A
Off-Shore Wind	No	No	N/A
Batteries	No	No	N/A

We were asked by stakeholders to consider off-shore wind, biomass, solar, and batteries in the ORTP process. In terms of off-shore wind, there are no off-shore wind projects in operation in the U.S., although there is a demonstration project that has entered a test phase in Rhode Island. Stakeholders suggested a review and application of data from off-shore wind projects operating in Europe. However, in consultation with MM, we determined that data from off-shore wind resources in Europe cannot be reasonably applied to a hypothetical off-shore wind farm in New England.

In considering biomass resources, it was determined that the variability of fuel and fuel gathering costs, as well as high initial capital costs, does not justify the calculation of a resource-specific ORTP.

Regarding battery technology, we determined that this technology is still in the development stages and that no reliable data exists on which to base an ORTP calculation.

An ORTP for solar resources ultimately was not recommended, although the industry has seen dramatic cost reductions over the past three years. Based on a conservative estimate for installed costs of approximately $2,100/kW (in 2016$) (compared to an assumed value of $3,139//kW in the 2013 ORTP study), we determined that costs remain too high to justify an ORTP below the expected auction starting price based on our recommended Net CONE technology and the associated value presented in this report.[59] In order for the ORTP for a solar resource to fall below the assumed auction starting price, the capacity factor for the solar resource must be approximately 18%. A review of historical data provided by ISO-NE showed a system-wide weighted average capacity factor of approximately 14%, which does not support an 18% capacity factor assumption.

We received input from stakeholders on the lack of a calculated ORTP value for some resources and the recommended ORTP value for other resources. It is important to note that FERC has opined on the absence of a resource-specific ORTP value. In its February 2013 Order, the FERC confirmed that

[59] Our estimated installed cost reflects an assumed a 7% annual capital cost improvement from 2015 to 2021 and an O&M cost decrease of approximately 30% from 2015 to 2021.

the lack of a resource-specific ORTP value does not create undue uncertainty or impose an unduly discriminatory burden on a developer. The FERC went on to state:

> "To the extent that a resource owner, including a consumer-owned utility, believes that its costs are lower than the applicable trigger price, it can seek a lower offer floor by submitting its unit-specific costs to the IMM."[60]

Based on the screening process as described above, we selected the following resources for which to calculate an ORTP value:

- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Onshore Wind
- Energy Efficiency
- Large Demand Response ("Large DR")
- Mass Market Demand Response ("Mass Market DR")

D. FINANCIAL ASSUMPTIONS

Similar to the calculation of Net CONE, the calculation of ORTP requires a real discount rate to translate uncertain future cash-flows to a levelized first year revenue requirement. The approach to determining the appropriate discount rate for ORTP values is identical to the approach taken for the calculation of Net CONE, except that the ORTP tariff specifies a contract for non-capacity revenues. As such, the inputs for cost of capital have to be adjusted accordingly to reflect a lower risk than that of the CONE calculation. Ultimately, the ORTP values reflect the "low end of the competitive range," and therefore require lower returns to equity and debt holders.

We determined that 7.3% is an appropriate after-tax weighted average cost of capital at which to evaluate ORTP values. This nominal discount rate is consistent with previous ORTP studies in New England.

To derive this ATWACC, we adjusted inputs to the cost of capital to reflect the low end of the competitive range and to account for the lower risk associated with contract-backed energy revenues. First, we adjusted the cost of debt to more closely reflect the generic corporate debt of a higher rated company. Instead of a cost of debt of 7.75% which aligns closely with a B rated company, we assumed a lower cost of debt of 6.5%, which is more in line with the average costs of debt for a company with a B+ rating.

Second, we adjust the return on equity a full percentage point lower to reflect contracted revenues according to the Power Purchase Agreement ("PPA") assumption specific in the tariff. We estimated ROE using the CAPM, equal to a risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." As discussed in Section 3.D, we reviewed estimates from Blue Chip, Value Line, Ibbotson, and Bloomberg for the inputs to the CAPM. We maintained the same approach for the calculation of beta as that of CONE. Instead of basing our ROE on the high end

[60] FERC Order Docket No. ER12-953-001, pg 13.

of the competitive range using a forward-looking estimate, we relied on the average results from the historical and forward looking estimates, with a resulting return on equity of 12.4%.

We maintained the assumed capital structure of 60/40 (D/E), and assume an overall after tax cost of capital of 7.3%, consistent with findings in previous ORTP studies.[61]

E. GAS-FIRED GENERATION ORTP

1. Technical Specifications

The calculation of both simple cycle and combined cycle ORTPs were based on the technical specifications developed in the CONE/Net CONE process described in this report and shown in Table 38 below. A stakeholder questioned the use of the combined cycle 7HA.02 as the reference unit for the combined cycle ORTP calculation since it is not clear that this model of generating resource has cleared in a recent FCA, thus violating one of our screening criteria. We believe this choice of technology is appropriate for the ORTP calculation and meets the screening criteria. Combined cycle resources have cleared in recent FCAs. While the specific choice of combined cycle machine has not been announced in all cases, the GE7HA.02 combined cycle machine is consistent with the assumption that the latest technology will be utilized at these sites.

Table 38: Gas-Fired Resource Technical Specifications

	Combined Cycle Machine	Simple Cycle Machine
Model	7HA.02	7HA.02
Capacity (MW)	533	338
Net Heat Rate (btu/kWh)	6,546	9,220
Qualified Capacity (%)	100	100
Duct firing	Yes	No
Primary fuel	Natural gas	Natural gas
Backup fuel	No. 2 oil	No. 2 oil
Location	Bristol County, MA	Bristol County, MA
Net Plant Capacity (MW)	533	338
Interconnection	• 2-mile electrical interconnection (to 345 kV system) plus network upgrades • 2-mile gas lateral plus metering station	• 2-mile electrical interconnection (to 345 kV system) plus network upgrades • 2-mile gas lateral plus metering station
Environmental controls	SCR and CO catalyst	SCR and CO catalyst
Plot size *(acres)*	15.0	8.1

[61] Brattle, 2013.

2. Capital/Operating Costs

The capital costs for both simple cycle and combined cycle combustion turbines were based on the capital costs calculated as part of the CONE/Net CONE analysis. Costs for insurance, electrical interconnection, property taxes, and contingency were reduced consistent with calculating a "low-end of the competitive range" value. Specifically, insurance was adjusted from 0.6% of overnight costs used in the CONE study to 0.3% for the ORTP study; electrical interconnection costs were reduced by 10% from the CONE values, property taxes were reduced from 3% to 1% to represent the negotiation of a *Payment In-Lieu-of Taxes* ("PILOT") agreement, and contingency was reduced by 5% from the CONE values. The resulting overnight costs and fixed O&M costs are shown below.

Table 39: Comparison of Costs – CONE/ORTP

Technology	Combined Cycle CONE	Combined Cycle ORTP	Simple Cycle CONE	Simple Cycle ORTP
Total Overnight Costs (2016$)	$517,699,000	$512,417,050	$263,399,000	$259,411,500
Fixed O&M (2021$/kW-mo)	$5.01	$3.87	$3.21	$2.47

3. Revenue Offsets

The process by which the E&AS offset is calculated for ORTP gas-fired technologies is identical to the calculation for CONE/Net CONE. The same LMP and gas forecasts were used, the gas-turbines were dispatched in the same manner, and the process by which the cash flows were levelized to calculate the offset remains the same.

While the tariff requires that the ORTP calculation assume that the output from the generating resource is sold pursuant to a PPA, we have applied the same energy and ancillary service revenue stream developed in the CONE/Net CONE analysis to the ORTP calculation. Based on our experience, future price forecasts provide an unbiased expectation of market prices in both the short-term markets as well as under a PPA structure.

Similarly, expected PFP revenues for the simple cycle and combined cycle combustion turbines are consistent with those used in the CONE/Net CONE analysis.

4. ORTP Calculation

Based on the above cost estimates, financial assumptions, and projected revenues, the recommended ORTP value is $6.503/kW-mo for a simple cycle combustion turbine, and $7.856/kW-mo for a combined cycle combustion turbine. The components of the calculation of this value are shown in Table 40 below.

Table 40: Gas Turbine ORTP Calculation

Reference Technology	Installed Capacity *(MW)*	Qualified Capacity *(MW)*	Installed Cost *(000$)*	Installed Cost *($/kW)*	ATWACC *(%)*	Fixed O&M *($/kW-mo)*	Gross CONE *($/kW-mo)*	Revenue Offets *($/kW-mo)*	ORTP *($/kW-mo)*
Combined Cycle	533	533	$591,266	$1,109	7.3	$3.87	$13.48	$5.62	$ 7.856
Combustion Turbine	338	338	$299,123	$885	7.3	$ 2.47	$9.81	$ 3.31	$ 6.503

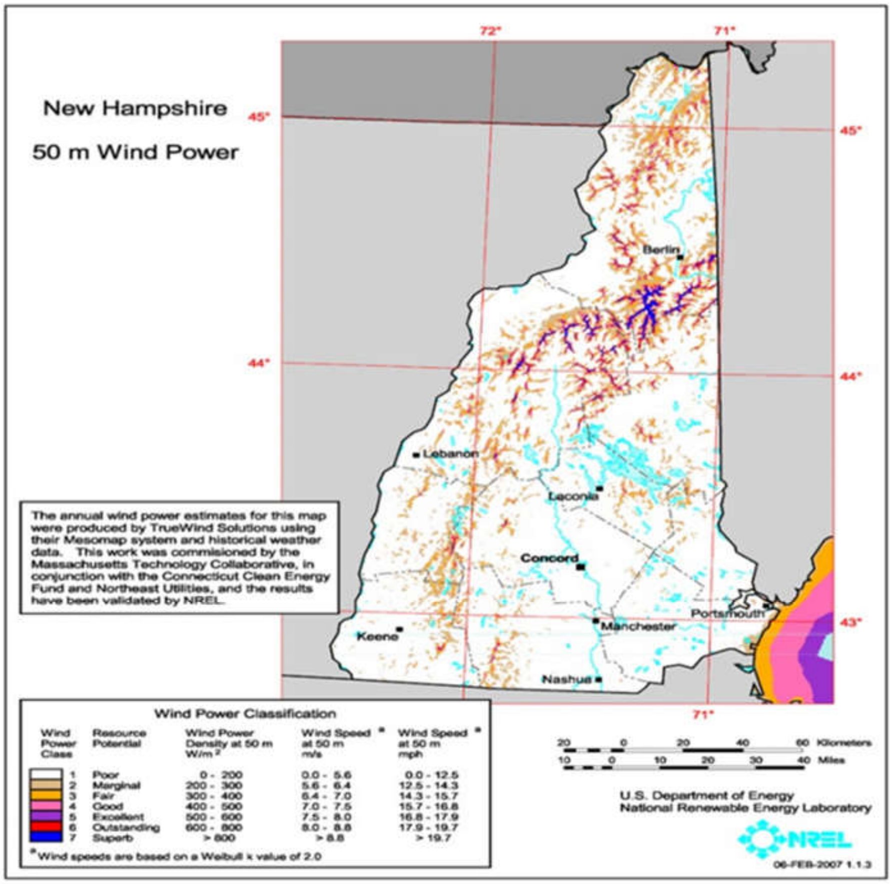
F. ON-SHORE WIND

1. Technical specifications

Our calculation of an ORTP value for an onshore wind farm began with developing assumptions about the appropriate size and location of a representative onshore wind farm in New England. A review of wind farms that participated in the most recent FCA, as well as wind farms currently in the interconnection queue, showed a large range of proposed sizes, ranging from 5 MW to 600 MW. In addition, a review of wind farms participating in the past two FCAs revealed sizes ranging from 20 MW to 80 MW of nameplate capacity. In determining an appropriate size for the reference wind unit, we weighted the range of wind resource participating in the most recent FCAs more heavily than the size of the wind resources in the interconnection queue since our criteria for screening wind resources was focused on resources that have recently participated in an FCA. Based on this information, the 60 MW reference wind farm size chosen for the 2013 ORTP study, and a discussion with stakeholders, we believe an onshore wind farm size of 52 MW, comprised of seventeen General Electric machines is an appropriate size on which to base our ORTP analysis.

In terms of location, wind resources are most appropriately located in areas with elevation differential and accessible transmission. Altitude improves wind resources in general, giving Northern New England a locational advantage. Available transmission to deliver the output from wind farms to load centers is an equally important consideration. We reviewed potential locations including New Hampshire, portions of Vermont, Maine, Western Massachusetts, and North Western Connecticut with these factors in mind. In light of these considerations and in consultation with MM, we determined central New Hampshire to be an appropriate location, as shown in Figure 12. This location is consistent with current operating and proposed wind farms, which are primarily located in Vermont, Maine and New Hampshire.

Figure 12: Wind Potential in New Hampshire



To estimate an appropriate capacity factor, we considered wind farms currently being offered into the FCA, as well as wind farms that have entered commercial operation in the past five years. A review of data provided by ISO-NE on wind farms that participated in the most recent FCA showed that estimated capacity factors had a large range, from 16% to 43%. Based on operating data provided by ISO-NE on five wind farms with a nameplate capacity over 20 MW that have been in operation since 2012, we calculated a weighted average capacity factor of approximately 29%. The efficiency of wind farms is expected to increase by 10% by 2020, therefore we believe that an upward adjustment to the capacity factor to approximately 32% for the reference onshore wind farm is appropriate.

To determine a reasonable qualified capacity, we reviewed the tariff requirements and the process by which wind farms are assigned a qualified capacity in the New England capacity market. According to the tariff, an intermittent resource's qualified capacity value for the summer and winter periods is set equal to the median of the net output during the summer and winter reliability hours for the previous five years.[62] [63] Since the qualified capacity of the wind resource is based on capacity

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[62] ISO-NE Market Rule 1 Section III.13.1.2.2.1.

[63] If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net

factor during reliability hours as calculated above, we assumed a qualified capacity of 30% consistent with the results of this calculation and a low end of the range approach to calculating an ORTP.

The specifications for the reference onshore wind resource is shown in Table 41.

Table 41: Reference Onshore Wind Farm Specifications

Specifications	Onshore Wind
Turbine Model	General Electric
Turbine Size	3 MWe
Net Plant Capacity	52 MW
Qualified Capacity	30%
Capacity Factor	32%
Location	Central New Hampshire
Plot Size	3,600 acres
Electrical Interconnection	115kV along existing transmission corridor

2. Capital Costs

Capital costs for onshore wind farms vary significantly from project to project due to site specific conditions and costs. In calculating an appropriate capital cost for the reference wind farm, we consulted MM, reviewed recent FCA submissions by wind developers for the latest available technologies, and reviewed publicly available data on the capital costs of wind farms. A review of the most recent FCA submissions showed that capital costs for similarly sized wind farms varied by over 25%. The installed costs submitted by participants is not provided in enough granularity to determine the specific sources of variation. Our assumed overnight costs for the reference wind farm are shown in Table 42. The overnight costs represent a decrease in the assumed cost for the reference wind farm from the 2013 ORTP study of $3,063/kW, reflecting the declining cost trajectory for wind farm installations.

output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period.

Table 42: Reference Onshore Wind Farm Overnight Costs (2016$)

Cost Component	Wind
Owner Project Cost	**110,000,000**
Owner's Costs (Services)	6,000,000
Electrical interconnection	14,000,000
Owners Contingency	1,750,000
Financing Fees	2,300,000
Working Capital	930,000
TOTAL NON-EPC COST	**24,980,000**
TOTAL OVERNIGHT CAPITAL COST	**$ 134,980,000**
Installed Capacity	52
$/kW	$ 2,596

Tax credits are currently available for eligible renewable resources in the form of a Production Tax Credit ("PTC") and the Investment Tax Credit ("ITC"). In our ORTP calculations, we have included the value of the PTC for wind. We assumed that the tax credits will continue to be available at their current respective rates through 2021. For the onshore wind ORTP calculation, the PTC is estimated to be $0.15/kWh in 2021 dollars, based on current rules and our assumed inflation rate.

3. Fixed O&M Costs

We estimated fixed O&M costs for onshore wind farms through consultation with MM and a review of the most recent FCA qualification materials provided by ISO-NE.

Land lease costs are typically negotiated and are therefore difficult to calculate. We assumed that 3,600 acres of land would be leased at a cost of approximately $860,000 or $240/acre, which is consistent with our review of ISO-NE data.

A property tax rate of 1% was assumed based on a review of independent power projects in New England that have entered into agreements for PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. This assumption was based on the fact that resources subject to PILOT agreements will have property tax expenses in each year of operation that will not vary significantly so that an average payment better reflects actual PILOT agreement structures. Based on this assumed rate, the property taxes for the onshore wind farm were estimated at approximately $130,000 per year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the assumption contained in the 2013 ORTP study, which continues to be reasonable. Annual insurance costs were estimated to be approximately $440,000 in 2021 dollars.

Ongoing maintenance costs were assumed to be approximately $1,800,000 per year based on a review of recent FCA submissions by onshore wind farms and consultation with MM.

Each of the above assumptions are an estimation of costs, since information on each of these cost categories is very limited and extremely site specific. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference onshore wind farm of $5.30/kw-month. A comparison of this all-in fixed O&M cost to recent FCA submissions shows this cost to be appropriately conservative, and less than the $6.88/kW-month assumed in the 2013 ORTP study.

4. Revenue offsets

Revenue offsets for the reference onshore wind farm include energy market revenues as well as revenues from renewable energy certificates ("REC's) and the PFP mechanism in the FCM.

To calculate energy margins, we assumed no variable costs so that the energy margins are equal to energy revenues. To calculate energy revenues, a projection of production, differentiated by month and time of day, was applied to the LMP forecast. Production assumptions were based on actual production data provided by ISO-NE. Wind resources do not receive AS revenues.

To calculate estimated REC revenues, we considered existing Renewable Portfolio Standards ("RPS") in New England, the expected entry of increasing renewable resources, and a third-party REC price projection. We have assumed a REC price over the forecast period of $26.50/MWh, which we believe appropriately reflects an expected future value of RECs in New England.

To calculate estimated PFP revenues, we reviewed the most recent ISO-NE projections of scarcity hours in New England, as more fully described in Section 3.E. We extrapolated a value of 6 hours of scarcity conditions per year over the next 3 years based on current excess capacity levels, and 11.3 hours over the balance of the forecast period. In addition, we obtained information from ISO-NE on the actual performance of onshore wind resources during Reserve Constraint Penalty Factor ("RCPF") hours over the last three years. This data showed that wind resources had a 93% performance rate. Assuming an 85% balancing ratio, wind resources are expected to receive PFP revenues of $0.04/kW-month for years 1-3 of the forecast period and $0.23/kW-month over the balance of the forecast period, as shown in Table 43 below.

Table 43: Expected Onshore Wind Farm PFP Revenues

Technology	Scarcity Hours (hrs)	Performance Payment Rate ($/MWh)	Average Actual Performance (%)	Average Balancing Ratio (%)	Net Performance Payments ($/kW-mo)	
Wind	11.3	$5,455	0.93	0.85	0.23	years 4 - 20
Wind	6	$3,500	0.93	0.85	0.04	years 1-3

5. ORTP Calculation

Based on the cost and revenue estimates, as well as our financial assumptions for the ORTP analysis, the first-year revenue requirement from the capacity market for the reference onshore wind farm is

$11.025/kW-mo, as shown in in Table 44. Therefore, we recommend an ORTP value for onshore wind of $11.025/kW-month.

Table 44: Wind Resource ORTP Calculation

Installed Capacity (MW)	52
Qualified Capacity (MW)	15.6
Capital Costs (Overnight) (2016$/kW)	2,596
ATWACC	7.30%
Fixed O&M ($/kW-mo)	$5.30
Gross CONE ($/kW-mo)	$30.55
Revenue Offsets ($/kW-mo)	$19.52
ORTP ($/kW-mo)	$11.025

G. ENERGY EFFICIENCY ORTP

1. Technical Specifications

Energy efficiency ("EE") resources participate in the FCM consistent with the manner in which supply-side resources participate. Companies that operate EE programs are permitted to enter peak-load reductions into the FCM.

Many of the existing EE programs are established through state-sponsored mandates and implemented by each state's investor-owned utilities. As defined in Section I of the ISO's tariff, EE includes installed measures (e.g., any combination of products, equipment, systems, services, practices, and strategies) on end-use customer facilities that reduce the total amount of electrical energy needed while delivering a comparable or improved level of end-use service. These measures can include the installation of more energy-efficient lighting, motors, refrigeration, HVAC (heating, ventilation, and air conditioning) equipment and control systems, and alternative operations and maintenance procedures. The programs generally cover the residential, commercial, and industrial sectors.

In calculating an appropriate ORTP for EE programs, we reviewed all investor -owned utility energy efficiency programs in New England. There are currently forty-six EE programs, excluding programs targeted towards low-income customers.[64] Table 45 shows the EE programs that have been included in our ORTP calculation.

[64] Low income programs were excluded to remain consistent with the previous *2013 Offer Review Trigger Prices Study* conducted by The Brattle Group. These programs include: Home Energy Solutions Income Eligible (CT), Single Family Income Based (MA), Multi Family Income Based (MA), Low-Income Direct Install Initiatives (ME), and Income Eligible (RI).

Table 45: Energy Efficiency Programs Included in ORTP Analysis[65]

Connecticut	Massachusetts	Maine	New Hampshire	Rhode Island	Vermont
Residential Retail Products	Residential Whole House	Business Incentive Program	ENERGY STAR Lighting	Residential New Construction	Business New Construction
Residential New Construction	Residential Products	Large Customer Program Electric Measures	ENERGY STAR Appliances	Energy Star HVAC	Business Existing Facilities
Home Energy Solutions	C&I New Construction	Small Business Initiative	ENERGY STAR Homes	EnergyWise	Residential New Construction
HVAC and Domestic Water Heating	C&I Retrofit	Consumer Products Program	Large C&I Retrofit	EnergyWise Multifamily	Efficient Products
Residential Behavior		Home Energy Savings Program	New Equipment and Construction	Energy Star Lighting	Existing Homes
C&I New Construction and Major Renovations (Energy Conscious Blueprint)			Municipal Energy Efficiency Program	Residential Consumer Products	
Energy Opportunities			Small Business Energy Solutions Program	Home Energy Reports	
Business and Energy Sustainability				Energy Efficiency Education Programs	
Small Business Energy Program				Residential Demonstration and R&D	
				Community Based Initiatives - Residential	
				Comprehensive Marketing - Residential	
				Large Commercial New Construction	
				Large Commercial Retrofit	
				Small Business Direct Install	
				Community Based Initiatives - C&I	
				Commercial Demonstration and R&D	

[65] Connecticut: Eversource Energy, et al., 2015.
Massachusetts: National Grid, et al., 2015.
Maine: Efficiency Maine, 2015.
New Hampshire: Granite State Electric Company, et al., 2015.
Rhode Island: National Grid, et al., 2015.
Vermont: Efficiency Vermont, 2016.

The investor-owned utility filings for the above programs contain information on forecasted program costs and savings. A review of these filings showed a potential annualized savings of 1,994,937 MWh and approximately 285 MW of summer peak-load savings at the customer meter over an estimated measure life of 11 years consistent with the average of existing programs. In order to present the information contained in the filings on a consistent basis, we adjusted the program size to 1 MW of capacity by the ratio of the annual energy savings to the peak load reduction. Based on this calculation, we assumed that a 1 MW EE measure would be expected to provide 7,009 MWh of annual energy savings.

2. Capital Costs

We calculated the total capital costs of the EE programs using data from the investor-owned utility annual EE program annual reports.[66] The total costs of the programs are shown below in Table 46.

Table 46: Energy Efficiency Programs Costs

		2015 Operating Costs (2016 $$)	2015 Operating Costs (2016 $kW)	2021 Operating Costs (2021 $/kW)
Peak Load Reduction				
At Meter	MW	264	264	264
At Generator Bus Bar		285	285	285
Total Operating Costs				
Labor & Services	$	135,348,148	476	525
Materials & Supplies	$	209,519	1	1
Incentives	$	536,724,551	1,886	2,082
Marketing, A&G, Other	$	96,355,155	339	374
Customer Costs	$	172,278,572	605	668
M&V	$	21,375,359	75	83
Total Utility Costs	2016$	962,291,304	3,381	3,733

3. Revenue Offsets

The calculation of revenue offsets includes both the value of the energy saved at the wholesale level, as well as avoided transmission and distribution costs. For the energy-related savings, we used the average forecasted on-peak locational marginal price produced by the Aurora simulation model for 2021 through 2031. For transmission and distribution cost savings, we used the Connecticut Light & Power avoided transmission and distribution costs that are used in their analyses of efficiency measure cost-effectiveness. The CL&P avoided T&D cost in 2015 was $33.44/kW-yr in 2015 dollars. Our analysis assumes the equivalent value in 2021 dollars of $37.66/kW-yr.

[66] Please note: the reports are provided as fiscal years and therefore time periods likely vary.

4. ORTP Calculation

Based on the estimated program savings and costs contained in the investor-owned utility filings, the Net CONE calculation is $-2.16/kW-month. Therefore, we recommend an ORTP value for EE programs of $0.00/kW-month.

Table 47: Energy Efficiency Program ORTP Calculation

Installed Capacity	MW	1
Qualified Capacity	MW	1
Capital Costs (Installed)	$/kW	3,733
Inlfation	%	2.0%
ATWACC	%	7.3%
ATWACC Real	%	5.2%
Annual Energy Savings	MWh	7,009
Energy Benefit	$/MWh	59.91
Avoided T&D Costs	$/kW-yr	37.66
Gross CONE	*$/kW-mo*	*35.97*
Levelized Capital Costs	$/kW-mo	35.97
Fixed O&M	$/kW-mo	0.00
Revenue Offsets	*$/kW-mo*	*38.13*
Energy Savings	$/kW-mo	34.99
T&D Savings	$/kW-mo	3.14
Net CONE	*$/kW-mo*	*-2.16*
ORTP	**$/kW-mo**	**0.00**

H. DEMAND RESPONSE RESOURCE ORTP

1. Technical Specifications

Demand response resources, like other supply resources, are competitive assets that help meet New England's electricity needs. By reducing consumption, demand resources can help ensure enough electricity is available to maintain grid reliability. Demand resources can take many forms. They can be a capacity product, type of equipment, system, service, practice, or strategy—almost anything that verifiably reduces end-use demand for electricity from the power system. (Reductions must be verified using an ISO-accepted measurement and verification protocol.) Demand response resources vary in size and type. As a result, capital costs span a large range.

Consistent with the categories established in the 2013 ORTP study, we assumed two classes of demand response with the following characteristics:

- Large DR – medium-sized commercial facility with a 2 MW peak load and the ability to reduce load by 25% assumed to be 500 kW. We assumed that the control technologies and systems required to implement the assumed peak load reduction are already in place, consistent with conservative cost assumptions to determine an ORTP at the low end of competitive range.

- Mass Market DR – a measure implemented by an investor-owned utility or state program focused on residential or small commercial customers that control specific end-use processes and can provide 1 kW of demand reduction.

2. Capital Costs

To determine the ORTP for Demand Response, Concentric reviewed the methodology, data, and analysis from the 2013 Offer Review Trigger Price Study ("2013 ORTP Study"). The 2013 ORTP Study identified challenges to obtaining detailed cost information due to (1) the variation in demand response resources, including in cost and type; and (2) limited available detailed data required to determine the ORTP. These challenges still apply.

As the 2013 ORTP study approach and resulting ORTP recommendations were based largely on interviews with DR aggregators, Concentric reached out to six DR aggregators to assess whether the information and methodology used in the 2013 ORTP study was still applicable. Several Interviewees offered general support for the ORTP methodology, values, assumptions, and ORTP recommendation from the 2013 study (i.e., that these continue to be applicable/ appropriate). Interviewees suggested variations to some of the values used in 2013. However, the majority of interviewees believed that the equipment costs, customer incentives and sales representative commission costs used in the 2013 study continued to be appropriate and fall within a reasonable range.

Based on this information, we used the capital costs contained in the 2013 ORTP study to estimate the equivalent costs in 2021, and assumed a total cost of $3,700. For the customer incentive payments, we assumed that these payments are 70% of the auction clearing price, consistent with the 2013 ORTP study, or approximately $4.92/kW-month. We assumed a 1% sales commission. This information is shown in Table 48 below.

For Mass Market DR, we used the information contained in the 2013 ORTP study, as well as information gained from our interviews. Interviewees generally agreed that it is appropriate to maintain the methodology from the 2013 ORTP study of keeping the two tiers of demand response in case such resources were to materialize going forward. Given a lack of additional cost information, we have adjusted the capital cost information contained in the 2013 ORTP Study for inflation. These values are shown in Tables 48 and 49 below.

Table 48: Large DR, Capital and Annual Cost Estimates

Cost Components	Cost (2021$)
Equipment Costs	3,714
Customer Incentives	4,326
Sales Commission	422

Table 49: Mass Market DR, Capital and Annual Cost Estimates

Cost Components	Cost (2021$)
Marketing, Sales and Recruitment	42
Equipment Costs	133
Customer Incentives	42
Total Installation Costs	***218***
Annual Customer Incentives	42
O&M Costs	11
Software/Communication	11

3. ORTP Calculation

Based on the cost estimates detailed above and the financial assumptions shown in Section 4.D, we recommend an ORTP value for Large DR of $1.01 as shown in Table 50 below.

Table 50: Large DR ORTP Calculation

Large Commercial and Industrial (Load Management C&I)		
	Assumptions	**Value ($/kW-mo)**
Demand Reduction (kW)	500	
Contract Life (years)	3	
ATWACC (%)	7.3%	
Capacity Clearing Price	$7.03	
Reconfiguration Auction Clearing Price	$1.03	
Customer Incentive	70% of Reconfiguration Clearing Price	$0.72
Sales Commission	1% of FCA Clearing Price	$0.07
Equipment Costs		$0.22
ORTP Value ($/kW-mo)		$1.01

Based on the cost estimates detailed above and the financial assumptions shown in Section 4.D, we recommend an ORTP value for Mass Market DR of $7.56 as shown in Table 51.

Table 51: Mass Market DR ORTP Calculation

Mass Market (Load Management Residential)	
	Assumptions / Value
Demand Reduction (kW)	1
Contract Life (years)	10
ATWACC (%)	7.3%
Installation Costs	$2.25
Annual Customer Incentives	$3.54
O&M Costs	$0.88
Software/Communication	$0.88
ORTP Value ($/kW-mo)	$7.56

I. ORTP ANNUAL UPDATE PROCESS

1. E&AS Revenues

E&AS revenues for gas-fired technologies will be updated consistent with the proposed update process contained in Section 4.K. For wind facilities, profitability is a function of the overall level of energy prices, not the spread between energy and gas prices. Therefore, the calculation supporting the adjustment of the energy portion of the E&AS offset is based only on the NEP futures. As of September 23, 2016, the average NEP settlement for 2021/2022 is $45.86/MWh. In the future, that average will be calculated again. The percentage difference (positive or negative) in the averages will be applied to the energy portion of the E&AS offset.

2. Capital and Fixed costs updates

Pursuant to tariff requirements, for years in which no full recalculation of CONE/Net CONE values is performed, the CONE/Net CONE values associated with the reference technology will be updated pursuant to the cost indices contained in Market Rule 1 Section III.A.21.2 for each relevant cost component. Indices covering the most recent 12 months at the time will be compared against the current values to calculate the appropriate escalation rates.

APPENDIX

Table A.52 below, shows average monthly prices for SEMA for On-Peak and Off-Peak hours for the forecast period 2021 to 2040.

Table A.52: Average Monthly On-Peak and Off-Peak SEMA LMPs (nominal $/MWh)

Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)	Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)
Jan-21	65.73	57.15	**Oct-23**	52.05	43.39
Feb-21	64.75	55.23	**Nov-23**	58.88	51.67
Mar-21	54.53	45.85	**Dec-23**	63.48	55.69
Apr-21	45.76	39.68	**Jan-24**	70.47	60.87
May-21	45.29	38.72	**Feb-24**	69.54	60.14
Jun-21	50.31	39.49	**Mar-24**	60.40	51.01
Jul-21	67.62	43.30	**Apr-24**	49.97	43.71
Aug-21	58.57	41.06	**May-24**	50.02	42.41
Sep-21	48.61	41.05	**Jun-24**	54.38	43.55
Oct-21	47.74	40.25	**Jul-24**	72.53	47.84
Nov-21	55.06	47.10	**Aug-24**	65.53	46.24
Dec-21	59.38	50.80	**Sep-24**	55.21	44.65
Jan-22	66.32	58.85	**Oct-24**	51.89	43.82
Feb-22	65.41	56.70	**Nov-24**	61.12	52.87
Mar-22	57.13	47.32	**Dec-24**	66.23	57.79
Apr-22	46.33	40.14	**Jan-25**	72.44	63.02
May-22	46.12	39.42	**Feb-25**	70.14	61.67
Jun-22	51.93	40.28	**Mar-25**	61.41	52.67
Jul-22	70.65	44.74	**Apr-25**	51.00	44.81
Aug-22	60.70	41.76	**May-25**	49.94	42.62
Sep-22	51.52	42.02	**Jun-25**	55.36	44.22
Oct-22	52.16	42.18	**Jul-25**	72.54	48.11
Nov-22	58.05	50.67	**Aug-25**	64.75	46.53
Dec-22	61.12	53.46	**Sep-25**	55.39	45.31
Jan-23	68.40	60.05	**Oct-25**	55.34	45.66
Feb-23	66.91	58.19	**Nov-25**	62.83	55.17
Mar-23	57.44	48.05	**Dec-25**	66.69	58.46
Apr-23	47.39	41.44	**Jan-26**	73.36	64.52
May-23	48.07	40.75	**Feb-26**	72.05	63.44
Jun-23	53.16	41.55	**Mar-26**	62.19	52.66
Jul-23	70.89	45.97	**Apr-26**	51.31	45.03
Aug-23	61.17	43.51	**May-26**	50.85	42.74
Sep-23	53.36	43.56	**Jun-26**	56.31	45.32
Aug-26	64.74	47.96	**Nov-29**	69.53	61.26

Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)	Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)
Sep-26	57.00	46.14	Dec-29	75.29	67.00
Oct-26	55.13	46.70	Jan-30	81.90	71.48
Nov-26	64.42	56.37	Feb-30	81.99	71.83
Dec-26	68.76	60.29	Mar-30	70.23	61.26
Jan-27	76.13	67.22	Apr-30	61.28	53.95
Feb-27	75.79	65.36	May-30	60.63	52.86
Mar-27	64.43	54.49	Jun-30	66.40	54.27
Apr-27	53.52	47.41	Jul-30	86.98	58.35
May-27	53.69	46.16	Aug-30	76.09	55.86
Jun-27	58.55	46.93	Sep-30	66.53	55.27
Jul-27	74.88	50.80	Oct-30	64.26	54.54
Aug-27	66.79	48.75	Nov-30	74.31	65.14
Sep-27	57.38	47.67	Dec-30	78.89	70.17
Oct-27	55.85	47.69	Jan-31	86.32	76.09
Nov-27	65.74	57.56	Feb-31	86.51	75.63
Dec-27	69.93	61.67	Mar-31	75.91	65.91
Jan-28	77.50	67.60	Apr-31	64.58	57.53
Feb-28	76.36	66.19	May-31	63.11	55.25
Mar-28	66.57	56.85	Jun-31	69.04	57.03
Apr-28	55.59	49.34	Jul-31	88.27	61.59
May-28	55.11	46.62	Aug-31	77.36	59.19
Jun-28	61.14	48.74	Sep-31	69.68	58.44
Jul-28	77.40	52.65	Oct-31	68.27	58.13
Aug-28	67.29	49.95	Nov-31	78.23	68.92
Sep-28	58.95	49.84	Dec-31	82.43	73.55
Oct-28	60.67	50.33	Jan-32	90.24	79.68
Nov-28	68.20	60.54	Feb-32	90.08	78.27
Dec-28	72.69	64.40	Mar-32	79.16	68.92
Jan-29	80.04	69.98	Apr-32	67.58	60.47
Feb-29	79.58	69.58	May-32	67.43	58.70
Mar-29	69.00	59.18	Jun-32	74.22	60.81
Apr-29	57.95	50.62	Jul-32	93.22	65.96
May-29	56.85	47.91	Aug-32	80.70	63.14
Jun-29	62.28	51.04	Sep-32	74.86	62.68
Jul-29	78.79	54.87	Oct-32	72.86	62.07
Aug-29	72.30	52.79	Nov-32	82.98	72.49
Sep-29	64.28	52.49	Dec-32	86.07	76.94
Oct-29	61.36	51.61	Jan-33	94.66	83.72
Feb-33	95.28	83.38	May-36	85.02	74.87
Mar-33	81.15	71.87	Jun-36	89.29	75.52

Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)	Month	Average On-Peak SEMA LMP ($/MWh)	Average Off-Peak SEMA LMP ($/MWh)
Apr-33	71.92	64.51	Jul-36	107.04	79.67
May-33	72.04	63.67	Aug-36	95.28	77.88
Jun-33	78.19	64.58	Sep-36	91.05	77.42
Jul-33	93.91	69.39	Oct-36	89.63	77.34
Aug-33	84.03	66.87	Nov-36	100.38	90.07
Sep-33	77.20	66.39	Dec-36	106.41	96.34
Oct-33	76.93	66.85	Jan-37	117.06	105.71
Nov-33	86.88	76.97	Feb-37	115.90	103.09
Dec-33	91.04	82.23	Mar-37	101.01	91.25
Jan-34	100.23	89.04	Apr-37	89.06	81.08
Feb-34	99.65	88.03	May-37	88.56	78.61
Mar-34	86.29	76.94	Jun-37	93.97	79.56
Apr-34	75.47	68.61	Jul-37	109.47	83.13
May-34	75.63	66.54	Aug-37	98.08	81.67
Jun-34	81.92	67.86	Sep-37	94.01	81.56
Jul-34	97.27	72.20	Oct-37	95.65	82.74
Aug-34	86.13	69.86	Nov-37	106.90	94.64
Sep-34	80.72	69.27	Dec-37	111.41	101.11
Oct-34	80.37	69.61	Jan-38	123.71	111.74
Nov-34	91.49	81.37	Feb-38	120.94	108.02
Dec-34	94.80	85.93	Mar-38	104.83	95.00
Jan-35	105.11	92.51	Apr-38	91.13	83.19
Feb-35	105.71	92.80	May-38	93.71	82.53
Mar-35	89.88	81.04	Jun-38	99.88	84.96
Apr-35	79.14	71.71	Jul-38	115.11	89.58
May-35	79.18	69.45	Aug-38	105.13	86.99
Jun-35	84.85	71.70	Sep-38	100.79	87.24
Jul-35	101.64	76.12	Oct-38	100.79	88.30
Aug-35	93.18	73.66	Nov-38	110.34	98.16
Sep-35	87.00	73.90	Dec-38	115.40	104.79
Oct-35	84.89	72.96	Jan-39	130.40	116.65
Nov-35	93.11	83.95	Feb-39	126.71	113.72
Dec-35	99.79	90.17	Mar-39	109.52	98.48
Jan-36	109.07	96.92	Apr-39	96.07	87.27
Feb-36	108.63	95.68	May-39	100.99	88.69
Mar-36	93.59	84.93	Jun-39	106.63	90.89
Apr-36	83.28	74.98	Jul-39	123.98	95.87
Aug-39	110.20	92.33	May-40	108.83	93.90
Sep-39	105.73	91.93	Jun-40	114.96	97.57
Oct-39	104.92	92.31	Jul-40	129.88	102.72

Month	Average On-Peak SEMA LMP *($/MWh)*	Average Off-Peak SEMA LMP *($/MWh)*	Month	Average On-Peak SEMA LMP *($/MWh)*	Average Off-Peak SEMA LMP *($/MWh)*
Nov-39	117.57	104.50	**Aug-40**	116.63	98.91
Dec-39	122.58	112.02	**Sep-40**	111.49	96.63
Jan-40	136.99	122.63	**Oct-40**	113.47	97.64
Feb-40	131.52	117.95	**Nov-40**	121.16	107.53
Mar-40	117.86	106.23	**Dec-40**	124.80	113.44
Apr-40	106.89	95.22			

Plant additions and retirements from the Aurora simulation are shown below. For each year, the amount of capacity added and/or retired is aggregate and includes the total change for each category in that year. Behind-the-meter resources are excluded.

Table A.53: Total Plant Additions and Retirements by Year (MW)

Year	Addition	Retirements
2021	772	560
2022	0	556
2023	386	547
2024	0	827
2025	386	354
2026	436	0
2027	326	0
2028	0	0
2029	50	330
2030	386	1,247
2031	386	0
2032	0	0
2033	772	0
2034	0	0
2035	0	876
2036	386	0
2037	436	0
2038	0	0
2039	0	0
2040	0	0

The load forecast used in the Aurora simulations is shown below in Table A.54 and Table A.55. As discussed above, the load forecast is based on the CELT report published by ISO-NE.

Table A.54: ISO New England Projected Load (GWh)

Year	1	2	3	4	5	6	7	8	9	10	11	12	Annual
2021	11,325	9,926	10,280	9,226	9,626	10,696	13,214	11,913	10,126	9,619	9,780	10,963	126,693
2022	11,301	9,862	10,210	9,132	9,637	10,740	13,136	11,901	10,022	9,564	9,767	10,910	126,182
2023	11,315	9,813	10,140	9,036	9,677	10,776	13,123	11,844	9,904	9,544	9,750	10,866	125,790
2024	11,208	10,268	10,142	9,116	9,445	10,281	13,161	11,979	10,067	9,536	9,507	10,757	125,467
2025	11,266	9,875	10,122	9,101	9,442	10,383	13,202	11,905	10,071	9,528	9,513	10,804	125,212
2026	11,230	9,826	10,098	9,047	9,396	10,465	13,221	11,825	10,016	9,460	9,536	10,808	124,927
2027	11,183	9,780	10,077	8,988	9,385	10,542	13,183	11,807	9,941	9,380	9,576	10,802	124,644
2028	11,155	10,055	9,963	8,824	9,476	10,653	13,100	11,756	9,737	9,337	9,577	10,728	124,362
2029	11,146	9,848	10,099	8,958	9,281	10,175	13,116	12,030	10,001	9,404	9,388	10,638	124,082
2030	11,159	9,808	10,002	8,944	9,268	10,171	13,188	11,943	9,947	9,365	9,357	10,654	123,805
2031	11,159	9,761	9,948	8,894	9,229	10,248	13,207	11,836	9,920	9,322	9,331	10,672	123,529
2032	11,095	9,992	9,901	8,781	9,176	10,411	13,164	11,720	9,781	9,172	9,398	10,663	123,255
2033	11,092	9,635	9,882	8,734	9,247	10,514	13,127	11,760	9,721	9,169	9,440	10,662	122,982
2034	11,121	9,593	9,819	8,641	9,305	10,568	13,126	11,711	9,604	9,161	9,435	10,627	122,712
2035	11,041	9,740	9,934	8,753	9,070	10,038	13,122	11,976	9,855	9,201	9,209	10,506	122,443
2036	11,029	10,013	9,776	8,691	9,022	10,112	13,197	11,759	9,769	9,121	9,151	10,538	122,176
2037	11,039	9,619	9,785	8,668	9,010	10,236	13,242	11,700	9,741	9,083	9,212	10,575	121,911
2038	10,991	9,571	9,767	8,609	9,002	10,324	13,203	11,683	9,662	9,000	9,261	10,573	121,648
2039	10,991	9,522	9,714	8,527	9,045	10,404	13,140	11,698	9,568	8,965	9,273	10,540	121,386
2040	10,998	9,792	9,556	8,409	9,134	10,467	13,147	11,594	9,315	8,971	9,261	10,482	121,126

Table A.55: ISO New England Projected Peak Load (MW)

Year	1	2	3	4	5	6	7	8	9	10	11	12	Annual
2021	19,795	19,095	17,656	15,612	16,679	22,230	26,355	21,704	19,510	16,412	17,972	19,152	26,355
2022	19,789	18,610	17,486	15,423	16,900	22,242	26,405	21,714	19,068	16,376	17,949	19,141	26,405
2023	19,795	18,460	17,414	15,389	17,304	22,269	26,472	21,738	19,066	16,350	17,939	19,142	26,472
2024	19,778	19,055	17,573	15,861	16,565	20,042	26,544	21,750	19,485	16,293	17,424	18,779	26,544
2025	19,825	19,097	17,605	15,715	16,591	20,630	26,636	21,810	19,529	16,317	17,455	18,819	26,636
2026	19,846	19,111	17,604	15,606	16,580	20,796	26,722	21,851	19,546	16,304	17,937	19,173	26,722
2027	19,879	19,135	17,612	15,449	16,573	22,441	26,818	21,899	19,570	16,297	17,949	19,201	26,818
2028	19,885	18,629	17,376	15,247	17,255	22,474	26,904	21,927	19,107	16,258	17,931	19,199	26,904
2029	19,915	19,156	17,714	15,817	16,550	20,181	26,987	22,362	19,603	16,270	17,452	18,870	26,987
2030	19,937	19,171	17,608	15,801	16,540	20,204	27,076	22,019	19,622	16,258	17,452	18,882	27,076
2031	19,961	19,188	17,609	15,609	16,531	20,803	27,166	22,062	19,641	16,248	17,452	18,896	27,166
2032	19,964	19,179	17,581	15,311	16,488	22,648	27,254	22,088	19,637	16,203	17,937	19,252	27,254
2033	20,024	18,709	17,462	15,178	16,798	22,718	27,356	22,158	19,205	16,234	17,982	19,309	27,356
2034	20,049	18,561	17,402	15,159	17,268	22,766	27,448	22,203	19,221	16,224	17,989	19,328	27,448
2035	20,061	19,256	17,731	15,728	16,498	20,328	27,532	22,643	19,724	16,207	17,457	18,956	27,532
2036	20,065	19,249	17,593	15,493	16,456	20,938	27,623	22,268	19,722	16,164	17,429	18,946	27,623
2037	20,112	19,291	17,625	15,413	16,481	21,135	27,719	22,330	19,767	16,188	17,998	19,372	27,719
2038	20,151	19,320	17,636	15,243	16,478	22,959	27,821	22,384	19,795	16,183	18,014	19,405	27,821
2039	20,180	18,789	17,473	15,064	16,763	23,010	27,917	22,433	19,306	16,179	18,025	19,428	27,917
2040	20,187	18,609	17,383	15,012	17,448	23,046	28,010	22,465	18,670	16,235	18,007	19,428	28,010

Attachment 2

AFFIDAVIT OF DANIELLE S. POWERS

1. My name is Danielle S. Powers. I am a Senior Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is an employee-owned management consulting and financial advisory firm focused on the North American energy industry specializing in utility regulation, finance and mergers and acquisitions, energy markets, management and operations support, as well as civil litigation and dispute resolution. Concentric is headquartered in Marlborough, Massachusetts. My office address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

2. I have over 25 years of experience in wholesale electric market design and operations, power generation, and energy consulting fields. I have been with Concentric for over 10 years. I am also a former employee of ISO New England Inc., where I was a Principal Analyst working on the design, implementation, and operation of the Forward Capacity Market. Prior to working at ISO New England Inc., I was a Senior Engagement Manager at Navigant Consulting from December 1999 to February 2003, where I managed asset sale transactions. From October 1997 to December 1999, I was employed at XEnergy, Inc. working on negotiating retail power supply contracts with large commercial and industrial customers.

3. I began my career in the energy industry in April of 1989, joining New England Power Company as a production engineer at Brayton Point Generating Station in Somerset, Massachusetts with responsibility for the design and operation of all environmental control equipment. I worked at New England Power Company until October 1997, over which time I worked in the transmission marketing, generation marketing and supply chain management departments.

4. I hold a B.S. in Mechanical Engineering from the University of Massachusetts, Amherst, and an M.B.A. from Bentley University.

I, in cooperation with Keith Paul of Mott MacDonald, was responsible for preparing the ISO-NE CONE and ORTP Analysis (referred to as the "CEA Report") and the information contained in that report is true and correct to the best of my knowledge.

Danielle S. Powers

Danielle S. Powers
January 13, 2017

Subscribed and sworn to before me
this 13th day of January 2017.

LAUREEN G. SASSEVILLE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
October 19, 2023

Laureen Sasseville
Notary Public

My commission expires: 10/19/2023

Attachment 3

AFFIDAVIT OF KEITH PAUL

1. My name is Keith Paul. I am a Senior Consulting Engineer at Mott MacDonald, Inc. ("Mott MacDonald") at their Boston office. Mott MacDonald is an engineering, management and development consultancy operating in 150 countries, through over 16,000 local experts in 180 principal offices. Mott MacDonald operates in the following sectors: Buildings, Communications, Defense, Education, Environment, Health, International development, Industry, Mining, Oil and gas, Power, Transport, Urban development, Water and wastewater. Mott MacDonald provides services to customers to plan, design, procure and deliver projects on any scale; provide management consultancy built on technical know-how, shape and implement development policies and programs; and advance sustainability. Our portfolio ranges from small projects worth thousands of dollars to the world's largest multidisciplinary, multi-billion dollar programs.

2. I have over 20 years of consulting, design, and development experience of power generation systems and subsystems on plants located around the world. My experience includes power plant design, engineering, operations, and project development. My consulting experience includes the development of project power cycles, site arrangements and detailed design documentation, development of project financial capabilities, and documentation of plant performance criteria to ensure target performance and financial goals.

3. I have been with Mott MacDonald since December 2015 in support of projects across the globe. Prior to joining Mott MacDonald, I worked for InterGen from 2012 to 2015, from 2009 to 2012 at Stone & Webster Management Consultants, from 2006 to 2009 at Power Advocate, from 1997 to 2006 at the Shaw Group and Stone & Webster Engineering Corporation, from 1995 to 1997 at TODD Combustion, from 1992 to 1995 New England Power, and from 1990 to 1992 at Narragansett Electric.

4. I hold a B.S. in Mechanical Engineering from Northeastern University and an M.B.A. from F.W. Olin Graduate School of Business at Babson College.

I, in cooperation with Danielle S. Powers of Concentric Energy Advisors, Inc, was responsible for preparing the ISO-NE CONE and ORTP Analysis (referred to as the "CEA Report") and the information contained in that report is true and correct to the best of my knowledge.

Keith Paul
January 12, 2017

Subscribed and sworn to before me
this 12th day of January 2017.

Notary Public

My commission expires: March 30, 2023

JEAN DILLON
MY COMMISSION EXPIRES MAR. 30, 2023
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

  (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

  (i) that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, and also shall publish the quantity of capacity from Demand Resources by type at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero, and;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-

TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the cleared amount of capacity determined by the System-Wide Capacity Demand Curve. If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or, if applicable, the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, Permanent De-list Bid, or Retirement De-List Bid shall clear based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, ~~2018~~ 2021 is $11.35/kW-month~~$14.04/kW-month~~.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, ~~2018~~ 2021 is $8.04/kW-month~~$11.08/kW-month~~.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e)~~, except that the energy and ancillary services offset will be adjusted using publicly available data for Mass Hub On-Peak electricity futures through the commitment period of the FCA and will not be adjusted based on natural gas prices~~. Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource’s Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

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

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability

Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity

Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III. III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export

Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market

Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***. This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market

Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;
(ii) Conduct and market outcomes that are inconsistent with competitive markets;
(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
(iv) Actions in one market that affect price in another market;
(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and
(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective.

Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant’s submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or
(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

  i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

  ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
    (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
    (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of

operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
(b) Costs must be documented.
(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.
(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be

calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor’s determination of a Resource’s marginal costs shall include an assessment of the Resource’s incremental operating costs in accordance with the following formulas,

Incremental Energy:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits; and,
(c) other operating permits that limit production of energy.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price) + no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

(a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.

(b) Competitiveness Evaluation of Energy Offer At Low Load.

  (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

  (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

(c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

(d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:

   i. The Start-Up Fee (cold start);

   ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and

iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{real\ time} / LMP_{day\ ahead}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed

Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.
Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.
If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.
Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
- (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
- (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
- (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
- (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
- (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Ninth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the <u>twelfth</u> ~~ninth~~ Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, ~~2018~~<u>2021</u>) shall be as follows:

Generation Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	<u>$6.503</u>~~$13.424~~
combined cycle gas turbine	<u>$7.856</u>~~$8.866~~
on-shore wind	<u>$11.025</u>~~$10.320~~

Demand Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	<u>$1.008</u>~~$1.145~~
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	~~$7.094~~ <u>$7.559</u>

previously installed Distributed Generation	~~$1.145~~$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the new Demand Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For new Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For new Demand Resources other than Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than Demand Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)"

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices ~~from the time of the update through the end of the Capacity Commitment Period associated with the relevant FCA,~~ and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021 ~~and the Algonquin City Gates natural gas prices for the 12 months following the time of the update~~, as published by ICE~~the CME Group~~.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.2.4, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Demand Resource, the resource's costs shall
include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response provider and end-use customers to acquire the Demand Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Demand Resource, and expected costs avoided by the end-use customer as a direct result of the installation or implementation of the Demand Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

(i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and

(ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and
(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant’s annual capacity revenue from the Lead Market Participant’s total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant’s total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant’s annual capacity revenue from the Lead Market Participant’s total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant’s total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be bid into the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

   (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits), or;

   (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

   (i) that interface's approved capacity transfer limit (net of tie benefits), or;

   (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price, and also shall publish the quantity of capacity from Demand Resources by type at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero, and;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the export-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and the quantity of capacity in the Capacity Zone from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-

TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the cleared amount of capacity determined by the System-Wide Capacity Demand Curve. If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or, if applicable, the administratively-determined payment rate (due to “Inadequate Supply” or “Insufficient Competition”) that applies to certain resources for Forward Capacity Auctions conducted prior to June 2015, paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. A Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, Permanent De-list Bid, or Retirement De-List Bid shall clear based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $8.04/kW-month.

CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the bid has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated if either of the following conditions is met in the initial auction clearing process: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation); or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation) and the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price. The second run of the auction-clearing process: (i) excludes all Proxy De-List Bid(s), (ii) includes the offers and bids of resources that did not receive a Capacity Supply Obligation in the first run of the auction-clearing process, and (iii) includes the capacity of resources, or portion thereof, that received a Capacity Supply Obligation in the first run of the auction-clearing process. The second run of the auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) that receive a Capacity Supply Obligation as a result of the first run of the auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. **Static De-List Bids and Export Bids**.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. **Dynamic De-List Bids.**

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. **Administrative Export De-List Bids**.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. **Reliability Review**.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid to determine whether the capacity associated with that de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station.. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. De-list bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) Where a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction.

(c) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject the de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability. Resources that submitted Permanent De-List Bids or Retirement De-List Bids shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii)).

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

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability

Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity

Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the Capacity Commitment Period for which the Retirement De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: submitted a Retirement De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III.13.1.2.3.1.5(d); elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction; or, for a resource, or portion thereof, that submitted a Permanent De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a) and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the Capacity Commitment Period for which its Permanent De-List Bid was submitted, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: submitted a Permanent De-List Bid that was not included in the Forward Capacity Auction pursuant to Section III. III.13.1.2.3.1.5(d); was subject to conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export

Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A
MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(c) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant’s submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,
(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,
(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or
(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;
(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO’s Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource’s available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.5 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.
Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.
A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.
A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.
If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.
Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 "General Threshold Energy Mitigation" or III.A.5.5.2 "Constrained Area Energy Mitigation" is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

   i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

   ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 "Constrained Area Energy Mitigation"), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 "Manual Dispatch Energy Mitigation" is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource's Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 "General Threshold Commitment Mitigation", III.A.5.5.5 "Constrained Area Commitment Mitigation", or III.A.5.5.6 "Reliability Commitment Mitigation" is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 "Start-Up Fee and No-Load Fee Mitigation" is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource’s Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource’s Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Supply Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of a Supply Offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;

(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,

(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.

(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.

(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.

(d) For any Operating Day for which, during the previous 90 days:

(i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

(ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(iii) The Market Participant submits a fuel price pursuant to Section III.A.3.4.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

    i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits; and,
(c) other operating permits that limit production of energy.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price) + no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. Determination of Offer Competitiveness During Shortage Event.

The Internal Market Monitor shall evaluate the competitiveness of the Supply Offer of each Resource with a Capacity Supply Obligation that is off-line during a Shortage Event, as described below. The evaluation for competitiveness shall be performed on Supply Offers in the Day-Ahead Energy Market and on Supply Offers in the Real-Time Energy Market. For purposes of these evaluations, Reference Levels are calculated using the cost-based method specified in Section III.A.7.5. The Real-Time Energy Market evaluation uses the final Supply Offer in place for the hour.

(a) Hours Evaluated. For Supply Offers in the Day-Ahead Energy Market, competitiveness is evaluated for all hours of the Operating Day during which a Shortage Event occurs. For Supply Offers in the Real-Time Energy Market competitiveness is evaluated for the last hour that the Resource could have been committed to be online at its Economic Minimum Limit at the start of the Shortage Event, taking into account the Resource's Start-Up Time and Notification Time.

(b) Competitiveness Evaluation of Energy Offer At Low Load.

  (i) If the Resource is not in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

  (ii) If the Resource is in a constrained area as determined under Section III.A.5.2.2, then the Supply Offer is not competitive if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

(c) Competitiveness Evaluation of Energy Offer Above Low Load. If a Supply Offer evaluated for competitiveness pursuant to Section III.A.8 (b) above is competitive for an hour, then the energy price parameter for each incremental Supply Offer block above the Resource's Economic Minimum Limit shall be evaluated for competitiveness using the thresholds identified in Section III.A.5.5.1.2, for Resources not in a constrained area, and the thresholds identified in Section III.A.5.5.2.2, for Resources in a constrained area, in order of lowest energy price to highest energy price. If any Supply Offer block is non-competitive, then that block and all blocks above it shall be non-competitive, and all blocks below it shall be competitive.

(d) Low Load Cost test. Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit for its Minimum Run Time, is calculated as the sum of:

  i. The Start-Up Fee (cold start);
  ii. The sum of the No Load Fees for the Resource's Minimum Run Time; and
  iii. The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Resource's Minimum Run Time.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer Block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer Block.

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor Demand Resources as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England

Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.
Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Filing Right.
If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, despite having submitted a Supply Offer at the Energy Offer Cap,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the hours of the Operating Day during which the Supply Offer was mitigated or during which the Resource was operated at the Energy Offer Cap, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having submitted a Supply Offer at the Energy Offer Cap, costs incurred for the duration of the period of time for which the Resource was operated at the Energy Offer Cap.

III.A.15.2. Contents of Filing.
Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating

the Resource exceeded the costs as reflected in the Supply Offer at the Energy Offer Cap; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.

III.A.15.4. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully

challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of reported demand levels.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets (“authorized government agencies”). With respect to state regulatory bodies and state attorneys general (“authorized state agencies”), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the

Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Ninth Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generation Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$6.503
combined cycle gas turbine	$7.856
on-shore wind	$11.025

Demand Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.559

previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources

All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the new Demand Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For new generation resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For new Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for new generation resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For new Demand Resources other than Demand Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for new generation resources, except that the model discounts cash flows over the contract life. For Demand Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources (other than Demand Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"
steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit

	Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the ninth FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included in the capital budgeting model for the ninth FCA will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO’s web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.2.4, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.2.4, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a new Demand Resource, the resource's costs shall
include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred by the Demand Response provider and end-use customers to acquire the Demand Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the Demand Resource, and expected costs avoided by the end-use customer as a direct result of the installation or implementation of the Demand Resource.

(iii) For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in

Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.21.3. Special Treatment of Certain Out-of-Market Capacity Resources in the Eighth Forward Capacity Auction.

For the eighth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2017), the provisions of Sections III.A.21.1 and III.A.21.2 shall also apply to certain resources that cleared in the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2015) and/or the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2016), as follows:

(a) This Section III.A.21.3 shall apply to: (i) any capacity clearing in the sixth or seventh Forward Capacity Auction as a New Generating Capacity Resource or New Import Capacity Resource designated as a Self-Supplied FCA Resource; and (ii) any capacity clearing in the sixth or seventh Forward Capacity Auction from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at prices found by the Internal Market Monitor to be not consistent with either: (a) the resource's long run average costs net of expected net revenues other than capacity revenues for a New Generating Capacity Resource and a New Demand Resource or (b) opportunity costs for a New Import Capacity Resource.

(b) For the eighth Forward Capacity Auction, the capacity described in subsection (a) above shall receive Offer Review Trigger Prices as described in Section III.A.21.1 and New Resource Offer Floor Prices as described in Section III.A.21.2. These values will apply to such capacity in the conduct of the eighth Forward Capacity Auction as described in Section III.13.2.3.2.

(c) For the eighth Forward Capacity Auction, the Project Sponsor or Lead Market Participant for such capacity may be required to comply with some or all of the qualification provisions applicable to new resources described in Section III.13.1. These requirements will be determined by the ISO on a case-by-case basis in consultation with the Project Sponsor or Lead Market Participant.

(d) For any capacity described in subsection (a) above that does not clear in the eighth Forward Capacity Auction:

> (i) any prior election to have a Capacity Clearing Price and Capacity Supply Obligation continue to apply for more than one Capacity Commitment Period made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 shall be terminated as of the beginning of the Capacity Commitment Period associated with the eighth FCA (beginning June 1, 2017); and
>
> (ii) after the eighth Forward Capacity Auction, such capacity will be deemed to have never been previously counted as capacity, such that it meets the definition, and must meet the requirements, of a new capacity resource for the subsequent Forward Capacity Auction in which it seeks to participate.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources in the Rest-of-Pool Capacity Zone;
(b) For each modeled import-constrained Capacity Zone, the greater of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;
(c) For each modeled export-constrained Capacity Zone, the lesser of: (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources within the export-constrained Capacity Zone plus, for each external interface connected to the export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and; (2) the Maximum Capacity Limit of the export-constrained Capacity Zone, and;
(d) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(e) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Resources located within the import-constrained Capacity Zone; and

(f) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import

Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

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